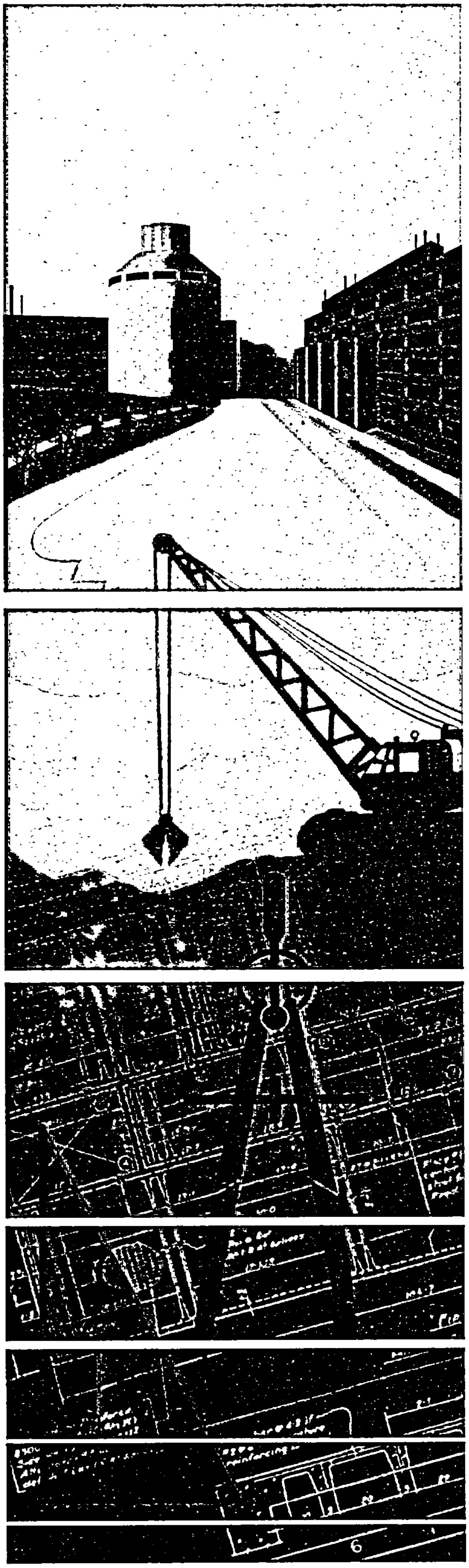

Final Safety Evaluation Report

Related to Certification of the AP1000 Standard Design

Volume 2

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation

September 2004

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ABSTRACT

This final safety evaluation report documents the technical review of the AP1000 standard nuclear reactor design by the U.S. Nuclear Regulatory Commission (NRC). Westinghouse Electric Company submitted the application for the AP1000 design on March 28, 2002, in accordance with Title 10 of the Code of Federal Regulations (10 CFR) Part 52, Subpart B, "Standard Design Certifications," and 10 CFR Part 52, Appendix O, "Standardization of Design: Staff Review of Standard Designs."

The AP1000 nuclear reactor design is a pressurized water reactor with a power rating of 3415 megawatts thermal (MWt) and an electrical output of at least 1000 megawatts electric (MWe). The AP1000 design contains many features that are not found in current operating reactors. For example, a variety of engineering and operational improvements provide additional safety margins and address the Commission's severe accident, safety goal, and standardization policy statements. The most significant improvement to the design is the use of safety systems that employ passive means, such as gravity, natural circulation, condensation and evaporation, and stored energy, for accident mitigation. These passive safety systems perform safety injection, residual heat removal, and containment cooling functions.

Some features of the AP1000, compared to currently operating reactors, include a longer reactor core design, a larger pressurizer, an in-containment refueling water storage tank, an automatic depressurization system, a revised main control room design with a digital microprocessor-based instrumentation and control system, hermetically sealed canned reactor coolant pump motors mounted to the steam generator, and increased battery capacity. In addition, the facility is designed for a 60-year life, which exceeds the projected 40-year combined operating license period, and employs structural modules.

On the basis of its evaluation and independent analyses, as set forth in this report, the NRC staff concludes that Westinghouse's application for design certification meets the requirements of 10 CFR Part 52, Subpart B, that are applicable and technically relevant to the AP1000 standard design. Appendix G includes a copy of the report by the Advisory Committee on Reactor Safeguards, as required by 10 CFR 52.53.

TABLE OF CONTENTS

Page

Page

Page

Page

Page

Page

Page

Page

Page

Page

Page

Page

Page

Page

Page

Page

APPENDICES

FIGURES

TABLES

Page

10. STEAM AND POWER CONVERSION SYSTEM

10.1 Introduction

The steam and power conversion system is designed to convert the heat energy generated by the reactor into electric power. The AP1000 Design Control Document (DCD) Tier 2, Chapter 10, "Steam and Power Conversion," describes the steam and power conversion system for the AP1000 design. This system generates electricity by using the main steam system to drive a turbine generator unit. Two steam generators produce steam from the heat energy generated by the reactor to supply the turbine for the main steam system.

The turbine exhaust steam is condensed and deaerated in the main condenser. A closed-loop circulating water system (CWS) removes the heat rejected in the main condenser. The condensate pumps take suction from the condenser and deliver the condensate water through heaters to the suction of the main feedwater booster pump. The water is next discharged to the suction of the main feedwater pumps, which then discharge the feedwater through feedwater heaters to the two steam generators.

Steam from each of the two steam generators enters the high-pressure turbine through four stop valves and four governing control valves. Crossties are provided upstream of the turbine stop valves to equalize pressure. The turbine bypass system provides the capability to relieve a combined capacity of 40 percent of total full-power steam flow to the condenser during startup, hot shutdown, cooldown, and step-load reductions in generator loads.

The protective features for the steam and power conversion system include the following:

- loss of external electrical load and/or turbine trip protection
- main steamline overpressure protection
- loss of main feedwater flow protection
- turbine overpressure protection
- turbine missile protection
- radioactivity protection
- erosion-corrosion protection

Spring-loaded safety valves are provided on both main steamlines for overpressure protection, in accordance with Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). The pressure relief capacity of the safety valves allows the energy generated at the high-flux reactor trip setting to be dissipated through this system. The design capacity of the main steam safety valves equals or exceeds 105 percent of the design steamflow of the nuclear steam supply system (NSSS) at an accumulation pressure not exceeding 110 percent of the design pressure of the main steam system.

DCD Tier 2, Section 10.1, and Table 10.1-1 provide a description of the steam and power conversion system, as well as its design features and performance characteristics.

10.2 Turbine Generator

The staff reviewed the design of the turbine generator in accordance with Section 10.2 of the Standard Review Plan (SRP). The design of the turbine generator system is acceptable if its integrated design meets the requirements of Part 50 of Title 10 of the Code of Federal Regulations (10 CFR Part 50). Specifically, the design must meet the requirements of Appendix A to 10 CFR Part 50, General Design Criteria for Nuclear Power Plants (GDC) 4, "Environmental and Dynamic Effects Design Bases," as they relate to the protection of the structures, systems, and components (SSCs) that are important to safety from the effects of turbine missiles. GDC 4 provides for a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generation of turbine missiles. SRP Section 10.2.11 describes the specific criteria necessary to meet the requirements of GDC 4.

The turbine generator converts the thermal energy into electric power. The turbine generator is designated as Model TC6F with a 137 centimeter (cm) (54 inch (in.)) last-stage blade unit. The AP1000 turbine generator has a heat balance output value of 1,199,500 kilowatts (kW) for the NSSS-rated thermal power of 3,415 megawatts thermal (MWt).

DCD Tier 2, Table 10.2-1 identifies the design parameters of the turbine generator. DCD Tier 2, Figure 10.3.2-2 provides the piping and instrumentation diagram (P&ID) containing the stop, governing control, intercept, and reheat valves. The turbine generator consists of a double-flow, high-pressure turbine and three double-flow, low-pressure turbines. Other related system components include a turbine generator bearing lubrication oil system, a digital electrohydraulic (DEH) control system, a turbine steam sealing system, overspeed protective devices, turning gear, a generator hydrogen and seal oil system, a generator carbon dioxide system, an exciter cooler, a rectifier section, and a voltage regulator.

The turbine generator foundation is designed as a spring-mounted support system. The springs dynamically isolate the turbine generator deck from the remainder of the structure in the range of operating frequencies.

Steam from each of the two steam generators enters the high-pressure turbine through stop valves and governing control valves. After expanding through the high-pressure turbine, exhaust steam flows through two external moisture separator/reheaters. The reheated steam flows through separate reheat stop and intercept valves leading to the inlets of the three low-pressure turbines. Turbine steam is supplied to feedwater heaters.

10.2.1 Overspeed Protection

The overspeed protection control of the DEH control system and the emergency trip system (ETS) protect the turbine against overspeed.

The overspeed protection control of the DEH control system opens a drain path for the hydraulic fluid in the overspeed protection control header, if the turbine speed exceed 103 percent of the rated speed. The loss of fluid pressure in the header causes the control and intercept valves to close. Following these valve closures, if the turbine speed falls below the rated speed and the header pressure is reestablished, the control and intercept valves are reopened and the unit resumes speed control. Section 10.2.2 of this report provides additional discussion of the DEH control system. In addition, an emergency trip system is provided to trip the turbine in the event that speeds exceed the overspeed protection control trip setpoint of 110 percent of the rated speed. Section 10.2.4 of this report provides additional discussion of the ETS.

10.2.2 Digital Electrohydraulic Control System

The turbine generator is equipped with a DEH control system. The DEH control system has two modes of operation to protect the turbine from overspeeding. The first mode is the speed control that functions to maintain the desired speed; the second mode is the overspeed protection control which operates if the normal speed control should fail or upon a load rejection.

The DEH control system combines the capabilities of redundant processors and high-pressure hydraulics to regulate steam flow through the turbine. The control system provides the functions of speed control, load control, and automatic turbine control (ATC). Section 10.2.3 of this report discusses the ATC. Valve opening actuation in the DEH control system is provided by a hydraulic system; closing actuation is provided by springs and steam forces upon reduction or relief of fluid pressure. A trip signal is sent to fast acting solenoid valves. Energizing these solenoid valves releases the hydraulic fluid pressure in the valve actuators, allowing springs to close each valve. The system is designed so that a loss of fluid pressure leads to valve closure and consequent turbine trip. Steam valves are provided in series pairs. A stop valve is tripped by the overspeed trip system; the control valve is modulated by the governing system and actuated by the trip system.

10.2.3 Automatic Turbine Control

The ATC regulates turbine speed and acceleration through the entire speed range. When the operator selects ATC, the programs both monitor and control the turbine.

The ATC is capable of automatically performing the following activities:

- changing speed
- changing acceleration
- generating speed holds
- changing load rates
- generating load holds

10.2.4 Turbine Protective Trips

The turbine protective trips are independent of the electronic control system and cause tripping of the turbine stop and control valves when initiated. The protective trips include the following:

- low bearing oil pressure
- low electrohydraulic fluid pressure
- high condenser back pressure
- turbine overspeed
- thrust bearing wear
- remote trip that accepts external trips

The ETS discussed in Section 10.2.1 of this report is designed for the turbine overspeed trip. The ETS can detect undesirable operating conditions of the turbine generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the corrective actions. The ETS consists of an emergency trip control block, trip solenoid valves, a mechanical overspeed device, three test trip blocks with pressure sensors and test solenoid valves, rotor position pickups, speed sensors, and a test panel.

The ETS utilizes a two-channel configuration which permits online testing with continuous protection afforded during the test sequence. A trip of the ETS opens a drain path for the hydraulic fluid in the auto stop emergency trip header. The loss of fluid pressure in the trip header causes the main stop and reheat stop valves to close. Also, check valves in the connection to the overspeed protection control header open to drop the pressure and cause the control and intercept valves to close. The control and intercept valves are redundant to the main stop and reheat stop valves respectively. DCD Tier 2, Section 10.2.2.8 states that major system components are readily accessible for inspection and are available for testing during normal plant operation. In addition, turbine trip circuitry is tested prior to unit startup.

The NRC staff reviewed the above information, as described in DCD Tier 2, Sections 10.2.1 through 10.2.3, to confirm that there is sufficient redundancy to ensure turbine overspeed protection. The staff determined that the AP1000 turbine generator design conforms to Acceptance Criteria II.1 and II.4 of Section 10.2 of the SRP.

The mechanical overspeed trip device consists of a spring-loaded trip weight mounted in the rotor extension shaft. The mechanical overspeed and manual trip header can be tripped manually via a trip handle mounted on the governor pedestal. The electrical overspeed trip system has separate, redundant speed sensors and provides backup overspeed protection utilizing the trip solenoid valves in the emergency trip control block to drain the emergency trip header. The speed control and overspeed protection function of the DEH control system, combined with the ETS electrical and mechanical overspeed trips, provides a sufficient level of redundancy and diversity.

10.2.5 Valve Control

Criterion II.2 of Section 10.2 of the SRP states that turbine main steam stop and control valves and reheat steam stop and intercept valves should be provided to protect the turbine from exceeding set speeds, as well as to protect the reactor system from abnormal surges. To assure that turbine overspeed is controlled within acceptable limits, the reheat stop and intercept valves should be capable of closure concurrent with the main steam stop valves or of sequential closure within an appropriate time limit. The valve arrangements and valve closure times should ensure that a failure of any single valve to close will not result in an excessive turbine overspeed in the event of a turbine generator system trip signal.

DCD Tier 2, Section 10.2.2.4.3 states that the flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. Each stop valve is controlled by an electrohydraulic actuator so that the stop valve is either fully open or fully closed. The stop valves shut off the steam flow to the turbine, when required. The stop valves fully close within 0.3 seconds of actuation of the ETS devices, which are independent of the electronic flow control unit.

The turbine control valves are positioned by electrohydraulic servo actuators in response to signals from their respective flow control units. The flow control unit signal positions the control valves for wide-range speed control through the normal turbine operating range, as well as for load control after the turbine generator unit is synchronized.

The reheat stop and intercept valves, located in the hot reheat lines at the inlet to the low-pressure turbines, control steam flow to the low-pressure turbines. During normal operation of the turbine, the reheat stop and intercept valves are wide open. The intercept valve flow control unit positions the valves during startup and normal operations, and closes the valves rapidly upon loss of turbine loads. The reheat stop valves close completely upon a turbine overspeed and turbine trips. Quick closure of the steam valves prevents a turbine overspeed. The valve closure time for both the reheat stop valves and intercept valves is 0.3 seconds. Because redundancy is built into the overspeed protection systems, the failure of a single valve will not disable the trip functions.

On the basis of the above discussion, the staff concludes that the AP1000 design conforms to Criteria II.2 and II.3 of Section 10.2 of the SRP with respect to the availability and adequacy of the control valves.

10.2.6 Turbine Missiles

The turbine generator and associated piping, valves, and controls are located completely within the turbine building. No safety-related systems or components are located within the turbine building. The orientation of the turbine generator is such that a high-energy missile would be directed at a 90-degree angle away from safety-related SSCs. Failure of the turbine generator equipment does not preclude a safe shutdown of the reactor. Section 3.5.1.3 of this report addresses the issue of turbine missiles.

10.2.7 Access to Turbine Areas

Criterion II.6 of Section 10.2 of the SRP states that unlimited access to all levels of the turbine area should be provided under all operating conditions. Radiation shielding should be provided as necessary to permit access.

Under operating conditions, access is available to the turbine generator components and instrumentation associated with a turbine generator overspeed protection. Major system components are readily accessible for inspection, and are available for testing during normal plant operation.

Since the steam generated in the steam generators is not normally radioactive, no radiation shielding is provided for the turbine generator and associated components. Radiological considerations do not affect access to system components during normal conditions.

Based on the above discussion, the staff concludes that the turbine generator design conforms to Criterion II.6 of Section 10.2 of the SRP. Furthermore, Criterion II.7 of Section 10.2 of the SRP states that connection joints between the low-pressure turbine exhaust and the main condenser should be arranged to prevent adverse effects on any safety-related equipment in the turbine room in the event of rupture (it is preferable not to locate safety-related equipment in the turbine room). Criterion II.7 is satisfied because the turbine building does not house any safety-related equipment.

10.2.8 Turbine Rotor Integrity

GDC 4 requires that SSCs important to safety shall be appropriately protected against environmental and dynamic effects, including the effects of missiles, that may result from equipment failure. Because turbine rotors have large masses and rotate at relatively high speeds during normal reactor operation, failure of a rotor may result in the generation of high-energy missiles and excessive vibration of the turbine rotor assembly. The staff reviewed the measures taken by the applicant to ensure turbine rotor integrity and reduce the probability of turbine rotor failure.

The staff used the guidelines of SRP Section 10.2.3, "Turbine Disk Integrity," to review and evaluate the information submitted by the applicant to maintain turbine rotor integrity and a low probability of turbine rotor failure with the generation of missiles. SRP Section 10.2.3 provides criteria to ensure that the turbine rotor materials have acceptable fracture toughness and elevated temperature properties. In addition, these criteria will ensure that the rotor is adequately designed and will be inspected prior to service, as well as receiving inservice inspections (ISIs) at approximately 10-year intervals during plant shutdowns.

The applicant provided its evaluation on turbine disk integrity which addressed all technical areas specified in SRP 10.2.3, including materials selection, fracture toughness, preservice inspection (PSI), turbine disk design, and ISI. For this evaluation, the applicant relied on the turbine missile methodology and analytical results documented in Westinghouse Commercial Atomic Power (WCAP)-15783, "Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines," and WCAP-15785, "Probabilistic Evaluation of Turbine Valve Test Frequency," for this evaluation. Section 3.5.1.3 of this report includes a description of the analyses and the staff's evaluation and acceptance of WCAP-15783 and WCAP-15785. Since high-pressure turbines have disks of smaller radius and lighter blades (less stresses) and are operated at a higher temperature (higher fracture toughness), the LP turbine results on missile generation bound the HP turbine results. SRP 10.2.3 addresses LP turbines only, and WCAP-15783 provides information on LP turbines accordingly.

DCD Tier 2, Section 10.2.3 provides information concerning the turbine rotor material. AP1000 turbine rotors are made from a vacuum-melted, deoxidized alloy steel (Ni-Cr-Mo-V) by processes which maximize steel cleanliness and provide adequate fracture toughness. DCD Tier 2, Section 10.2.3 indicates that the turbine rotors are made from forgings that meet the requirements of materials specification ASTM A470, Class 5, 6, and 7, with strict limits being imposed on phosphorous, aluminum, antimony, tin, argon, and copper. This is a typical material used for Westinghouse turbine rotors and its performance in service has been found acceptable. The staff also finds this specification acceptable because use of this specification limits these impurities in the turbine rotor. The use of this materials specification is necessary to assure an appropriate level of fracture toughness.

The applicant stated in DCD Tier 2, Section 10.2.3.1, "Materials Selection," that the turbine materials have the lowest fracture appearance transition temperature(FATT) and the highest Charpy V-notch (C_V) properties obtainable from water-quenched Ni-Cr-Mo-V material of the size and strength level used, thus indicating that suitable material toughness is obtained through the use of these types of material. The applicant's response to request for additional information (RAI) 251.023 resolved the NRC staff's concern about FATT and the ni-ductility temperature (NDT). The applicant's response to RAI 251.024 dated March 25, 2003, clarified their fracture toughness requirements. This response indicated that the fracture toughness of the rotor materials will be at least 220 MPa$\sqrt{}$m (200 ksi$\sqrt{}$in.), and the ratio of fracture toughness to the maximum applied stress intensity factor for rotors at speeds from normal to design overspeed will be at least 2. The staff finds these toughness and margin criteria to be acceptable because they are consistent with criteria approved for other applications involving assumed flaws, such as the pressure-temperature limits for the reactor pressure vessel. However, this criterion for fracture toughness of the rotor material was not consistent with the second design criterion of DCD Tier 2, Section 10.2.3.4, which states that "[t]he tangential stresses will not cause a flaw that is twice the corrected ultrasonic examination reportable size to grow to critical size in the design life of the rotor." This was draft safety evaluation report (DSER) Open Item 10.2.8-1.

In a letter dated July 7, 2003, the applicant provided a response to this open item by revising DCD Tier 2, Section 10.2.3.4. This revision explicitly connects the applied stress intensity factor for an ultrasonic testing (UT) reportable flaw to fracture toughness of the rotor material. Since the applicant has removed the conflict between the criteria, Open Item 10.2.8-1 is resolved.

In DCD Tier 2, Section 10.2.3.2, "Fracture Toughness," the applicant discusses, in general terms, the maximum initial flaw size and crack growth rates. Section 3.5.1.3 of this report discusses the staff's evaluation of the application of nondestructive examination (NDE), initial flaw size, and crack growth rates with respect to the probability aspects of turbine missile generation. To ensure that the maximum applied stress intensity factor for rotors at various speed was derived appropriately, the NRC staff reviewed DCD Tier 2, Section 10.2.3.2.1, "Brittle Fracture Analysis," and requested additional information in RAIs 251.025, 251.026, and 251.027 to resolve certain concerns about the applicant's analysis.

DCD Tier 2, Section 10.2.3.2.1 describes a brittle fracture analysis in terms of the design duty cycle stresses, number of cycles, ultrasonic examination capability, and growth rate of potential flaws. In its response to RAI 251.025 regarding the conservative factors of safety that were included in estimating the above-mentioned parameters, the applicant referred to the low cycle fatigue (LCF) crack analysis of WCAP-15783. (WCAP-15783 is used to support the NRC staff's review of turbine missiles presented in DCD Tier 2, Section 3.5.1.3, as well as its review of the turbine rotor integrity presented in DCD Tier 2, Section 10.2.3.) WCAP-15783 describes completely the brittle fracture analysis discussed in DCD Tier 2, Section 10.2.3.2.1. The staff considers this response appropriate because the limiting dimension (radius) of a rotor shaft is much larger than the limiting dimension (disk thickness) of turbine disks, which makes the operational stresses in the shaft much lower than the operational stresses in the disks, and makes the disks more limiting than the shaft. Hence, the WCAP-15783 analyses for disks are sufficient for assessing overall rotor integrity.

In Revision 2 of WCAP-15783, the applicant replaced an unreasonable stress intensity factor (K_{IC}) value used in the LCF analysis, as identified in RAI 251.025, with a proprietary value the staff considers reasonable for the design material. In its response to RAI 251.026, dated March 25, 2003, regarding the vibratory stresses, the applicant referred to WCAP-15783 and stated that

> (t)he vibratory stress when passing through critical speeds during startups and shutdowns is not included in the evaluation of low cycle fatigue. This is because the bending stress for this condition is greatest on the surface of the rotor and negligibly small on the rotor bore surface, which is the point where maximum stress of low cycle fatigue appears.

The NRC staff considers this to be appropriate because the vibratory stress occurred at a location different from where the LCF effect is evaluated. However, the response did not adequately justify the conclusion that rotor resonant stresses resulting from passing through rotor critical speeds are insignificant. This was DSER Open Item 10.2.8-2.

In response to DSER Open Item 10.2.8-2 dated June 24, 2003, the applicant provided quantitative information regarding rotor resonant stresses resulting from passing through rotor critical speeds. This new information indicates that (1) the reported rotor resonant stresses are about one quarter of those associated with high cycle fatigue (HCF), as discussed in WCAP-15783, and (2) the duration of the rotor resonant stresses is short as opposed to the cyclic nature of HCF, making the contribution of the rotor stresses to HCF or LCF negligible at its critical speeds. Therefore, DSER Open Item 10.2.8-2 is resolved.

In its response to RAI 251.027 regarding the K_{IC} value, its associated safety factor, and the assumed initial flaw depth that was used in the fatigue crack growth analysis, the applicant stated that the requested information can be found in WCAP-15783. Further, the applicant addressed the issue regarding the assumed initial crack depth in its response to RAI 251.002(a) on undetected and reported indications. The crack growth analysis and results due to LCF have been evaluated and accepted in the staff's evaluation of DCD Tier 2, Section 3.5.1.3, related to turbine missiles; however, RAI 251.002 addresses the determination of an initial flaw depth. The closure of DSER Open Item 3.5.1.3-1 in Section 3.5.1.3 of this report further addresses this issue.

In RAI 251.028, the NRC staff discussed concerns about the uncertainties involved in using the results from the mechanical property tests, such as FATT, C_V, and yield strength, to verify the fracture toughness of rotor materials. In its response to RAI 251.028, dated March 25, 2003, regarding the assumed K_{IC} value of 220 MPa$\sqrt{m}$ (200 ksi$\sqrt{in}$) and the use of plant-specific rotor test data provided by the combined license (COL) applicant to support this assumed value, the applicant states that the assumed fracture toughness for LCF evaluations is based on the design curves for fracture toughness of 3.5 percent Ni-Cr-Mo-V steel. The fracture toughness curves provided reflect Mitsubishi Heavy Industry's (MHI) test data and experience and include a 20 percent margin. The applicant further states "[t]he minimum allowable fracture toughness for the AP1000 LP rotor at temperature will be 220 MPa$\sqrt{m}$ = 200 ksi$\sqrt{in}$." This expected fracture toughness is supported by approximately 190 actual toughness values for MHI rotors calculated using the Rolfe-Novak-Barsom correlation formula. The staff determined that there is ample margin between the assumed K_{IC} value used in the LCF evaluations and the expected K_{IC} value of 220 MPa$\sqrt{m}$ (200 ksi$\sqrt{in}$) for an actual rotor, especially when the assumed K_{IC} value includes a 20 percent margin. However, as required by DCD Tier 2, Section 10.2.6, the COL applicant referencing the AP1000 design will have available plant-specific turbine rotor test data and calculated toughness curves to confirm the material property assumptions in the turbine rotor analysis. (See Section 10.5 of this report, COL Action Item 10.5-2.)

DCD Tier 2, Section 10.2.3.4, "Turbine Rotor Design," indicates that the AP1000 turbine rotor design will be a solid-forging, fully-integral rotor rather than disks shrunk on a shaft. The current practice employed by some turbine manufacturers for the large, low-pressure, fully-integral rotors is to bore the center to remove metal impurities and permit internal inspection. The fully-integral, forged rotors will not be as susceptible to stress-corrosion cracking (SCC) as the shrunk-on disks due to the reduction of surfaces susceptible to SCC and the elimination of interference fits which induce higher stresses. The nonbored design of the high-pressure rotors provides increased design margins because of inherently lower centerline stress. The use of solid rotor forgings was qualified by an evaluation of the material removed from center-bored rotors used in fossil power plants. This evaluation demonstrated that the material at the center of the rotors meets the requirements of the materials specification. Further, DCD Tier 2, Section 10.2.3.4 states that only suppliers that have been qualified based on bore materials performance will supply forgings for high-pressure rotors. Therefore, both the nonbored design of the high-pressure turbine element and the bored design of the low-pressure turbine element is acceptable.

DCD Tier 2, Section 10.2.3 also states that the maximum tangential stress resulting from centrifugal forces does not exceed 65 percent of the 0.2 percent offset yield strength at design temperature and speed. The DCD also states that the tangential stresses will not cause a flaw that is twice the corrected UT reportable size to grow to critical size in the design life of the rotor. The first criterion is not consistent with the stress limit criterion of SRP 10.2.3, which stipulates that the combined stresses of a low-pressure turbine disk at design overspeed due to centrifugal forces, interference fit, and thermal gradients not exceed 0.75 of the minimum specified yield strength of the material. This was DSER Open Item 10.2.8-3. In its letter of

July 7, 2003, the applicant responded to this open item by revising the first design criterion of DCD Tier 2, Section 10.2.3.4, to be consistent with the stress limit criterion of SRP 10.2.3. Hence, DSER Open Item 10.2.8-3 is resolved.

DCD Tier 2, Section 10.2.3.5, "Preservice Tests and Inspections," states that the PSI will include a 100 percent volumetric (ultrasonic) examination of each finished machined rotor and a surface visual and magnetic particle examination. Every subsurface ultrasonic indication is either removed or evaluated to ensure that it will not grow in size and thus compromise the integrity of the turbine during service. All finished machined surfaces are subjected to a magnetic particle examination with no flaw indications permissible in bores or other highly stressed areas. Each turbine rotor assembly is spin tested at 120 percent of its rated speed. The proposed preservice tests and inspections, as well as the acceptance criteria for the examination results are more restrictive than those specified for Class 1 components in Section III and V of the ASME Code. Therefore, the staff finds them acceptable.

DCD Tier 2, Section 10.2.3.6, "Maintenance and Inspection Program Plan," states that the ISI for the AP1000 turbine assembly includes the disassembly of the turbine and complete inspection of all normally inaccessible parts, such as couplings, coupling bolts, low-pressure turbine blades, and low-pressure and high-pressure rotors. During plant shutdown, turbine inspections will be performed at intervals of approximately 10 years for low-pressure turbines and about 8 years for high-pressure turbines. At least one main steam stop valve, one main steam control valve, one reheat stop valve, and one intercept valve will be dismantled and inspected by visual and surface examinations approximately every 3 years during scheduled refueling or maintenance shutdowns. Turbine valve testing will be performed at quarterly intervals.

In RAI 251.029, the NRC staff requested justification for the inspection and testing intervals for the turbine system and valves. In its response to RAI 251.029, the applicant stated that "the turbine inspection interval of assembly and valves is determined based on not only the probability of turbine missile generation but also operating experience of similar equipment and inspection results." The response further clarified that the turbine inspection intervals are supported by WCAP-15783 and WCAP-15785, while the quarterly testing frequency for valves is supported by WCAP-15785 alone. WCAP-15783 demonstrates that except for the destructive overspeed mechanism, the probability of turbine missile generation does not exceed 10^{-5} per reactor-year, even after a running time between inspections of several times longer than 10 years. Section 3.5.1.3 of this report discusses the NRC staff's review and acceptance of WCAP-15783, which is related to the resolution of Open Items 3.5.1.3-1 and 3.5.1.3-2.

WCAP-15785 complements WCAP-15783 by using detailed nuclear turbine failure data to assess the total risk of turbine missile ejection at destructive overspeed and at lower overspeeds as a function of valve test interval. WCAP-15785 contains detailed information regarding the method for calculating the probability of destructive overspeed using historical failure data pertinent to the operating experiences of MHI nuclear steam turbines. This WCAP report also outlines the use of this failure data to calculate failure rates for various components. The NRC staff's review determined that the method described above is acceptable because the failure rate calculation methodology for valves and control systems is consistent with industry practice that has resulted in satisfactory performance. In addition, the probability of failure calculation methodology is a bounding approach. WCAP-15785 presents the total probability of turbine missile generation at destructive overspeed as a function of the turbine valve test interval and demonstrates that the probability of turbine missile generation with quarterly valve tests is 10^{-5} per reactor-year, less than the NRC criterion of 10^{-4} per reactor-year (as discussed in Section 3.5.1.3 of this report). Hence, the staff finds these inspection intervals acceptable. However, as required by DCD Tier 2, Section 10.2.6, the COL applicant referencing the AP1000 design must submit a turbine maintenance program to the NRC for review and approval within 3 years of obtaining a COL. (See Section 10.5 of this report, COL Action Item 10.5-2.)

10.2.9 Conclusions

Based on the above evaluation, the staff concludes that the AP1000 design is acceptable and meets the requirements of GDC 4 with respect to the protection of SSCs important to safety from the effects of turbine missiles. The applicant has met these requirements by providing a turbine overspeed protection system to control the turbine action under all operating conditions. This system also assures that a full-load turbine trip will not cause the turbine to overspeed beyond acceptable limits, thus resulting in turbine missiles.

With the resolution of DSER Open Items 10.2.8-1, 10.2.8-2, 10.2.8-3, and 3.5.1.3-1, the staff concludes that the integrity of the turbine rotor is acceptable and meets the relevant requirements of GDC 4 of Appendix A to 10 CFR Part 50. This conclusion is based upon the ability of the applicant to demonstrate that its design meets the requirements of GDC 4 with respect to the use of materials with acceptable fracture toughness, adequate design, and the requirements for PSIs and ISIs. The applicant has also described its program for assuring the integrity of low-pressure turbine rotors, which includes the use of suitable materials of adequate fracture toughness, conservative design practices, PSI and ISI, and valve testing. This provides reasonable assurance that the probability of failure due to missile generation is low during normal operation, including transients up to design overspeed.

10.3 Main Steam Supply System

10.3.1 Main Steam Supply System Design

The staff reviewed the design of the main steam supply system (MSSS) in accordance with Section 10.3 of the SRP. Acceptability of the design of the MSSS is based on meeting the following:

- GDC 4 with respect to the ability of the safety-related portions of the system to withstand the effects of external missiles and internally generated missiles, pipe whip, and jet impingement forces associated with pipe breaks

- GDC 5, "Sharing of Structures, Systems, and Components," with respect to the ability of the shared systems and components important to safety to perform required safety functions

- GDC 34, "Residual heat removal," as related to the system function of transferring residual and sensible heat from the reactor system in indirect cycle plants

The NRC staff review also considers the following guidance:

- SRP Branch Technical Position (BTP) RSB 5-1 with respect to the design requirements for residual heat removal

- Issue 1 in NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976, Memorandum From Director, NRR, to NRR Staff," which specifies the allowable credit that can be taken for valves downstream of the main steam isolation valve (MSIV) to limit blowdown of a second steam generator in the event of a steamline break upstream of the MSIV

The MSSS includes components of the AP1000 steam generator system (SGS), main steam system, and main turbine system. The function of the MSSS is to transport steam from the steam generators to the high-pressure turbine over the entire operating range. The system provides steam to the moisture separator/reheater and the steam seal system for the main turbine. The system removes heat generated by the NSSS by means of a steam dump to the condenser through the turbine bypass system or to the atmosphere through power-operated atmospheric relief valves or spring-loaded main steam safety valves, when either the turbine generator or condenser is unavailable.

DCD Tier 2, Section 10.3.1.1, and DCD Tier 2, Table 3.2-3, "Steam Generator System (SGS)," identify all safety-related mechanical equipment in the MSSS and list the associated ASME Code class. The following MSSS components are classified as safety-related:

- the main steamline piping from the steam generator up to the pipe restraint located on the wall between the auxiliary building and the turbine building, including the main steam isolation valve and the main steam isolation bypass valves

- the inlet piping from the main steamline to the main steam safety valve discharge piping and vent stacks and to the power-operated relief line piping, including block valve and power-operated relief valves

- the instrumentation tubing up to, and including, the main steamline pressure instrument root valves

- the vent line and nitrogen connection on the main steamline up to, and including, the first isolation valve

- the main steam drain condensate pot located upstream of the main steam isolation valves, as well as the drain piping up to, and including, the first isolation valve
- the condensate drain piping from the outlet of the isolation valve to the restraint on the wall between the auxiliary building and the turbine building

The remainder of the MSSS is non-safety-related.

As stated in the DCD, the safety-related portion of the MSSS complies with the quality assurance (QA) requirements of Appendix B to 10 CFR Part 50 and is designed to the requirements discussed in DCD Tier 2, Sections 3.11 and 9.5 for environmental design and fire protection, respectively. The DCD also states that no single failure coincident with loss of offsite power compromises the safety functions of the MSSS.

Provision III.5.f of SRP Section 10.3 states that in a postulated safe-shutdown earthquake, the design includes the capability to operate atmospheric dump valves remotely from the control room so that cold shutdown can be achieved using only safety-grade components, assuming a concurrent loss of offsite power. In the AP1000 design, the passive residual heat removal (PRHR) system (see Section 5.4.14 of this report), which can be initiated automatically without requiring the control of steamline pressure, provides the capability of safety-grade decay heat removal. The power-operated atmospheric relief valves provide a non-safety-related means for plant cooldown to the point that the normal residual heat removal system can be initiated to remove the decay heat. The relief valves are automatically controlled by steamline pressure, with remote manual adjustment of the pressure setpoint from the control room. If the relief valve for an individual main steamline is unavailable because of the loss of its control or power supply, the respective spring-loaded safety valves, which are safety-related, will provide overpressure protection. The safety valves are designed to AP1000 Class B; ASME Code, Section III, Class 2; and seismic Category I requirements. Therefore, the staff concludes that the AP1000 design meets the position in BTP RSB 5-1 as it relates to the design requirements for residual heat removal.

Following a main steamline break, the main steam isolation system is designed to limit blowdown to one steam generator so that the fuel design limits and containment design pressure can be maintained. The MSIVs and the MSIV bypass valves on each main steamline are designed to isolate the secondary side of the steam generators to prevent the uncontrolled blowdown of more than one steam generator and to isolate non-safety-related portions of the system. The MSIV automatically closes upon receipt of either of two main steam isolation signals associated with independent Class 1E electrical divisions. Redundant power supplies and power divisions operate the MSIVs and the MSIV bypass valves. The isolation valve is a part of the containment isolation boundary and therefore is specified as Class 1E, active, ASME Code, Section III, Class 2. The conditions that initiate automatic closure of the MSIVs and MSIV bypass valves are high containment pressure, low steamline pressure, high steamline pressure negative rate, and low reactor coolant inlet temperature. The MSIVs are gate valves controlled by a pneumatic/hydraulic operator. The energy required to close the valves is stored in the form of compressed nitrogen in one end of the actuator cylinder. High-pressure hydraulic fluid maintains the values in an open position. For emergency closure, redundant Class 1E solenoid valves are energized, causing the high-pressure hydraulic fluid to be dumped to a fluid reservoir and the valves to close. The backup isolation valves (such as the turbine stop valves) receive signals derived from the protection and safety monitoring system (PMS) to actuate the valves.

In DCD Tier 2, Section 3.6.1.1, the applicant stated that turbine stop valves, moisture separator/reheater stop valves, and turbine bypass valves (which are not safety-related) are credited in single-failure analyses to mitigate postulated steamline ruptures. These valves are included as non-safety-related equipment, and are evaluated for pipe whip protection as part of the evaluation of the affected system, as required by GDC 4. Based on the design alternatives identified in Issue 1 of NUREG-0138 relative to utilizing the turbine stop valves to provide redundancy for safety-related equipment, the turbine stop valves and control valves are credited for demonstrating that the design will preclude the blowdown of more than one steam generator, assuming a concurrent single active failure. The staff concluded in NUREG-0138 that in accidents involving spontaneous failures of secondary system piping, reliance on non-safety-grade valves in the postulated accident evaluation is permitted based on the reliability of these valves. The MSIV technical specification (TS) includes control for the turbine stop valves, moisture separator/reheater stop valves, and turbine bypass valves. Based on the conclusions in NUREG-0138, the staff finds that the AP1000 MSSS meets the requirements of GDC 34, as they relate to limiting blowdown of a second steam generator in the event of a steamline break upstream of the MSIV. Further, based on meeting the relevant acceptance criteria specified in the SRP, the staff concludes that the MSSS meets the requirements of GDC 34, as they relate to the system function of transferring residual and sensible heat from the reactor system.

Compliance with GDC 2, "Design Bases for Protection Against Natural Phenomena," is based on meeting the relevant acceptance criteria specified in the SRP to ensure that the safety-related portions of the system are capable of withstanding the effects of natural phenomena such as earthquakes, tornados, hurricanes, and floods. The design should also meet, the positions of Regulatory Guide (RG) 1.29, "Seismic Design Classification," as they relate to the seismic design classification of system components, and RG 1.117, "Tornado Design Classification," as they relate to the protection of SSCs important to safety from the effects of tornado missiles.

The AP1000 piping and valves from the steam generators up to, and including, each MSIV are designed in accordance with ASME Code, Section III, Class 2, and seismic Category I requirements. The branch lines up to, and including, the first valve (including a safety or relief valve) that is either normally closed or capable of automatic/remote manual closure are also designed to these requirements. Piping and valves downstream of the MSIVs and the valves identified above are designed in accordance with ASME Code, Section III, Class 3, and seismic Category I up to, and including, pipe anchors located at the auxiliary building wall. The power supplies and controls necessary for safety-related functions of the MSSS are designated Class 1E.

In DCD Tier 2, Sections 10.3.1.1 and 10.3.3, the applicant stated that the safety-related portion of the system is designed to withstand the effects of a safe-shutdown earthquake, is protected from the effects of natural phenomena, and is capable of performing its intended function following postulated events. The safety-related portion of the MSSS is located in the containment and auxiliary buildings, which are designed to withstand the effects of earthquakes, tornados, hurricanes, floods, external missiles, and other appropriate natural phenomena. The components of the safety-related MSSS are qualified to function in normal, test, and accident environmental conditions. Section 3.4.1 of this report describes the staff's evaluation of flood protection. The safety-related mechanical equipment in the MSSS is identified in DCD Tier 2, Table 3.2-3, and described in DCD Tier 2, Section 10.3.1.1. Based on its review, the staff concludes that the safety-related portion of the system meets the requirements of GDC 2 of Appendix A to 10 CFR Part 50 with respect to the ability of the structures housing the safety-related portion of the system and the safety-related portions of the system to withstand the effects of natural phenomena.

Compliance with GDC 4 is based on meeting the relevant requirements specified in the SRP to ensure that the safety-related portions of the system are capable of withstanding the effects of external missiles, internally generated missiles, pipe whip, and jet impingement forces associated with pipe breaks and Position C.1 of RG 1.115, "Protection Against Low-Trajectory Turbine Missiles," as it relates to the protection of SSCs important to safety from the effects of turbine missiles. In addition, the SRP states that the system design should adequately consider steam hammer and relief valve discharge loads to assure that system safety functions can be achieved and should assure that operating and maintenance procedures include adequate precautions to avoid steam hammer and relief valve discharge loads. The system design should also include protection against water entrainment.

Steam hammer prevention is addressed by appropriate precautions in the operating and maintenance procedures, which include system operating procedures that caution against using the MSIVs except when necessary, as well as operating and maintenance procedures that emphasize proper draining. The applicant also stated that the stress analyses for the safety-related portion of the MSSS piping and components include the dynamic loads from rapid valve actuation of the MSIVs and the safety valves. Design features that prevent water formations in the MSSS include the use of drain pots and the proper sloping of lines.

DCD Tier 2, Sections 3.6.1 and 3.6.2 discuss high-energy pipe break locations and evaluate the effects of such breaks, including pipe whip and jet impingement forces. DCD Tier 2, Section 10.3.2.2.1 states that the main steamlines between the steam generator and the containment penetration are designed to meet the leak-before-break (LBB) criteria. DCD Tier 2, Section 3.6.3 discusses the LBB application and criteria. Section 3.6.1 through 3.6.3 of this report provides the staff's evaluation of this issue. Leakage detection for the purpose of LBB is discussed in Section 3.6.3 of this report.

Section 3.5 of this report includes an evaluation of the protection provided by the AP1000 design against externally- and internally-generated missiles. Sections 3.5 and 3.6 of this report evaluates the conformance of the design in this area with the requirements of GDC 4.

Although the AP1000 design can be used at either single-unit or multiple-unit sites, DCD Tier 2, Section 3.1.1 states that the AP1000 design is a single-unit plant. Further, if more than one unit were built on the same site, none of the safety-related systems would be shared. Should a multiple-unit site be proposed, the COL applicant must apply for the evaluation of the units' compliance with the requirements of GDC 5, "Sharing of Structures, Systems, and Components," with respect to the capability of shared SSCs important to safety to perform their required safety functions.

As described above, the staff has reviewed the MSSS in accordance with Section 10.3 of the SRP and finds that the system design conforms to the requirements of GDC 2, 4, 5, and 34. Therefore, the design of MSSS is acceptable.

10.3.2 Steam and Feedwater System Materials

The staff reviewed DCD Tier 2, Section 10.3.6, "Steam and Feedwater System Materials," in accordance with Section 10.3.6, "Steam and Feedwater System Materials," of the SRP. The materials selection, fabrication, and fracture toughness of ASME Code Class 2 and 3 pressure boundary components in the steam and feedwater system are acceptable if they meet the relevant requirements of 10 CFR 50.55a, "Codes and Standards": Appendix A to 10 CFR Part 50, GDC 1, "Quality Standards and Records," and GDC 35, "Emergency Core Cooling System"; and Appendix B to 10 CFR Part 50, "Quality Assurance Criteria."

GDC 1 requires, in part, that SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. This requirement is satisfied when the requirements of 10 CFR 50.55a are met.

GDC 35 requires, in part, that suitable interconnection, leak detection, isolation, and containment capabilities be provided to assure that the safety system function (i.e., emergency core cooling) can be provided assuming a single failure. For ferritic pressure-retaining components of a critical nature, the containment capability is assured, in part, by requiring minimum fracture toughness performance of the materials form which they are fabricated.

Appendix B to 10 CFR Part 50 establishes QA requirements for the design, construction, and operation of SSCs that are important to safety.

The specific acceptance criteria necessary to meet these requirements are as follows:

- The fracture toughness properties of the ferritic materials of Class 2 and 3 components are acceptable if they meet the requirements of NC-2300, "Fracture Toughness for Materials (Class 2)" and ND-2300, "Fracture Toughness for Materials (Class 3)" of Section III of the ASME Code.

- The materials specified for use in Class 2 and 3 components are acceptable if they conform to Appendix I of Section III of the ASME Code, and to Parts A, B, and C of Section II of the Code. Materials acceptable to the staff are also specified in RG 1.85, "Materials Code Case Acceptability—ASME Section III, Division 1."

- The materials specified for use in Class 2 and 3 components are acceptable if the regulatory positions of RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," are met. This guide describes methods acceptable to the staff for prevention of intergranular stress-corrosion cracking (IGSCC)of austenitic stainless steel and nickel-based alloy components.

- The materials specified for use in Class 2 and 3 components are acceptable, provided the acceptance criteria of ASME Section III, Paragraphs NB/NC/ND 2550 through 2570 for nondestructive examination of tubular products are followed.

- The materials specified for use in Class 2 and 3 components are acceptable if welds located in areas of restricted direct and visual accessibility are welded by personnel qualified consistent with the guidance of RG 1.71, "Welder Qualification for Areas of Limited Accessibility." This guide describes methods acceptable to the staff for providing better control of welder technique in production welding.

DCD Tier 2, Section 10.3.6, "Steam and Feedwater System Materials," indicates that the material specifications for pressure-retaining materials in the safety-related portions of the main steam and feedwater systems meet the fracture toughness requirements of Section III of the ASME Code, Articles NC-2300 and ND-2300, for Quality Group B and Quality Group C components. Pipe, flanges, fittings, valves, and other piping material conform to the referenced standards of ASME, the American Society for Testing and Materials (ASTM), the American National Standards Institute (ANSI), or the Manufacturer Standardization Society—Standard Practice Code. No copper or copper-bearing materials are used in the steam and feedwater system. Materials selection and fabrication requirements for ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems are consistent with the requirements for ASME Class 2 and 3 systems and components outlined in DCD Tier 2, Sections 6.1.1.1 and 6.1.1.2, for engineered safety feature (ESF) components. DCD Tier 2, Table 10.3.2-3 list the material specifications for the main steam and feedwater systems. DCD Tier 2, Section 1.9.1 describes conformance with the applicable RGs. DCD Tier 2, Section 6.6.5 addresses nondestructive inspection of ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems.

The staff's evaluation of the materials used in the main steam and feedwater systems is divided into the following three sections:

(1) Fracture Toughness: DCD Tier 2, Section 10.3.6.1 indicates that the fracture toughness properties of the materials of the main steam and feedwater systems will meet the requirements of Section III of the ASME Code, Articles NC-2300 and ND-2300 for Quality Group B and C components, respectively. The fracture toughness requirements of the Code provide reasonable assurance that the materials will have adequate margins against the possibility of nonductile behavior or rapidly propagating fracture. This satisfies, in part, the requirements of 10 CFR 50.55a, GDC 1, and GDC 35.

(2) Material Selection and Fabrication: Carbon steel piping in steam and feedwater systems has experienced wall thinning due to single-phase or two-phase erosion-corrosion. DCD Tier 2, Section 10.1.3 indicates that erosion-corrosion resistant materials are used in steam and power conversion systems for components exposed to single-phase or two-phase flow where significant erosion can occur. The applicant stated that it considered system piping and component configuration and geometry, water chemistry, piping and component material, fluid temperature, and fluid velocity in its evaluation of erosion-corrosion. In addition to material selection, pipe size and layout may also be used to minimize the potential for erosion-corrosion in systems containing water or two-phase flow. Carbon steel with only carbon and manganese alloying agents will not be used for applications subject to erosion-corrosion. In addition, the steam and feedwater systems are designed to facilitate inspection and erosion-corrosion monitoring programs. The COL applicant will perform pipe wall thickness inspections to monitor the presence of excessive wall thinning.

An industry-sponsored computer program developed for nuclear and fossil power plant applications is used to evaluate the rate of wall thinning for components and piping potentially susceptible to erosion-corrosion. The engineering models are the result of research and development in the fields of material science, water chemistry, fluid mechanics, and corrosion engineering. The COL applicant will prepare an erosion-corrosion monitoring program for the carbon steel portions of the steam and power conversion systems that contain water or wet steam. This monitoring program will address industry guidelines and the provisions included in GL 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning." This is COL Action Item 10.3.2-1.

DCD Tier 2, Section 10.3.6.2 indicates that material selection and fabrication requirements for ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems are consistent with either the requirements for ASME Class 2 and 3 components or with the staff positions in RG 1.85. Since the materials meet the criteria of SRP 10.3.6, and since erosion/corrosion is addressed by selection of resistant materials and by inservice monitoring, the applicable requirements of GDC 1 are satisfied and thus the staff finds the material selection acceptable.

DCD Tier 2, Section 10.3.6.2 indicates that conformance with applicable RGs is described in DCD Tier 2, Section 1.9.1. The staff noted that in DCD Tier 2, Appendix 1A, "Compliance with Regulatory Guides," the applicant stated that the AP1000 design provides an alternative to RG 1.71. Section 5.2.3 of this report includes the staff's evaluation of this alternative. DCD Tier 2, Section 1.9.1 indicates that the AP1000 design will comply with RG 1.37 with respect to the prevention of IGSCC in components fabricated from austenitic stainless steel and nickel-based alloys. Since the AP1000 design conforms with these RGs, the applicable requirements of GDC 1 and Appendix B to 10 CFR Part 50 are satisfied.

(3) Nondestructive Inspection: DCD Tier 2, Section 10.3.6.2 indicates that DCD Tier 2, Section 6.6.5 addresses the nondestructive inspection of ASME Code, Section III,

Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems. DCD Tier 2, Section 6.6, indicates that the rules for fabrication examinations found in Section III of the ASME Code will be followed. Section 6.6 of this report evaluates this section of the DCD. Therefore, the fabrication of the materials specified for use in Class 2 and 3 components will comply with the acceptance criteria of Section III of the ASME Code, Paragraphs NB/NC/ND 2550 through 2570 for nondestructive examination of tubular products. These criteria are in accordance with SRP 10.3.6 and satisfy, in part, the requirements of 10 CFR 50.55a and GDC 1. Therefore, they are acceptable to the staff.

The staff concludes that the AP1000 steam and feedwater system materials will be acceptable since they meet the acceptance criteria of SRP 10.3.6 and satisfy the applicable requirements of 10 CFR 50.55a; Appendix A to 10 CFR Part 50, GDC 1 and 35; and Appendix B to 10 CFR Part 50.

10.4 Other Features

10.4.1 Main Condenser

The staff reviewed the design of the main condenser in accordance with Section 10.4.1 of the SRP. The acceptability of the system design is contingent upon meeting the requirements of GDC 60, "Control of Releases of Radioactive Materials to the Environment," as they relate to the design of the system to ensure that failures do not result in excessive releases of radioactivity to the environment, do not cause unacceptable condensate quality, and do not flood areas housing safety-related equipment.

DCD Tier 2, Section 10.4.1 describes the main condenser system of the AP1000 design; DCD Tier 2, Figure 10.4.7-1 depicts this design. DCD Tier 2, Table 10.4.1-1, "Main Condenser Design Data," lists the design parameters of the condenser (such as heat transfer capability, surface area, design operating pressure, shell-side pressure, circulating water flow, tube-side inlet temperature, tube-side temperature rise, condenser outlet temperature, condenser tube material, etc.).

The main condenser system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine system. When the system functions as the steam cycle heat sink, it receives and condenses exhaust steam from the main turbine and the turbine bypass system. The main condenser is designed to receive and condense the full-load main steam flow exhausted from the main turbine. It also serves as a collection point for vents and drains from various components of the steam cycle system. Upon actuation of the turbine bypass system, the main condenser is designed to receive and condense steam bypass flows of up to 40 percent of the plant's full-load steam flow without either reaching the condenser overpressure turbine trip setpoint or exceeding the allowable exhaust temperature. In the event of high condenser pressure or a trip of both circulating water pumps, the turbine bypass valves are prohibited from opening. If the main condenser is unavailable to receive this flow, the steam is discharged to the atmosphere through the main steam power-operated relief valves or the spring-loaded safety valves.

The main condenser is a non-safety-related and nonseismic component located in the turbine building. The failure of the main condenser and the resultant flooding will not preclude operation of any essential system because safety-related equipment is not located in the turbine building. In addition, water cannot reach the safety-related equipment located in Category I plant structures. Therefore, the staff finds that the requirements of GDC 60 are met with respect to preventing flooding of areas housing safety-related equipment due to system failures.

The main condenser has no significant inventory of radioactive contaminants during normal operation and plant shutdown. Radioactive contaminants can be obtained through primary-to-secondary system leakage resulting from steam generator tube leaks. Early detection of concentrated levels of radioactivity is provided by the MSSS and steam generator blowdown system (BDS) radiation devices. In addition to this monitoring, radioactive effluent monitoring equipment is provided in the turbine island vents, drains, and relief system (TDS) at the combined exhaust of the condenser air removal system (CMS) and the turbine gland seal system (GSS). The plant operator may secure the discharge of the radioactive effluent upon detection of a high radioactivity level. Although the design has radioactivity monitors in the system to detect leakage into and out of the main condenser during normal operation, startup, and shutdown, the main condenser has no radioactive contaminants inventory. Because the above systems continuously monitor and detect the radioactivity leakage into and out of the condenser, GDC 60 is met with respect to failures in the system design that could result in excessive releases of radioactivity to the environment. Section 11.5 of this report discusses the radiological monitoring capabilities of the AP1000 design.

The main condenser is not subject to ISI testing. The condenser water boxes are hydrostatically tested after erection. Condenser shells are tested by the fluorescent tracer method in accordance with ASME Performance Test Code 19.11. Tube joints are leak tested during construction and prior to startup.

The system is provided with the following instrumentation and control features to determine and verify the proper operation of the main condenser:

- the main condenser hotwell level control devices
- control room indicators and alarms of water levels in the condenser hotwell
- control room indicators and alarms of condenser pressure
- a turbine trip on high turbine exhaust pressure
- temperature indicators for monitoring condenser performance

The main condenser interfaces with the secondary sampling system to permit sampling of the condensate in the hotwell to determine in-leakage from the circulating water system. Each tube sheet is also provided with a grab sampling capability. This information helps to identify the leaking tube bundle. The steps that may be taken to repair a leaking tube bundle include

(1) isolate the circulating water system from the affected water box while at reduced plant power, (2) drain the water box, and (3) repair or plug the affected tubes.

The condensate polishing system (CPS) removes corrosion products and ionic impurities from the condensate system. This allows for continued operation with a "continuous" condenser tube leakage of 0.004 liters per minute (L/min) (0.001 gallons per minute (gpm)) or a "faulted" leak of 0.4 L/min (0.1 gpm) until repairs can be made or until an orderly shutdown is achieved. DCD Tier 2, Table 10.3.5-1 provides secondary cycle chemistry guidelines. DCD Tier 2, Section 10.3.5.5 discusses action levels for abnormal secondary cycle chemistry. Therefore, the staff finds that the requirements of GDC 60 are met with respect to condenser failures that do not result in unacceptable condensate quality.

As discussed above, the staff reviewed the design of the main condenser in accordance with Section 10.4.1 of the SRP. On the basis of this review, the staff concludes that the main condenser system is acceptable and meets the requirements of GDC 60 with respect to the prevention of excessive releases of radioactivity to the environment resulting from failures in the system design. The AP1000 design meets this requirement by providing radioactive monitors in the system to detect leakage into and out of the main condenser.

10.4.2 Main Condenser Evacuation System

The condenser air removal system (CMS) is responsible for the evacuation of the main condenser. The staff reviewed the design of the CMS in accordance with Section 10.4.2 of the SRP. Acceptability of the design of the CMS is based on meeting the following GDC as described in the SRP:

- GDC 60, as it relates to the CMS design for the control of releases of radioactive materials to the environment

- GDC 64, "Monitoring Radioactivity Releases," as it relates to the CMS design for the monitoring of releases of radioactive materials to the environment

The SRP includes RG 1.33, "Quality Assurance Program Requirements (Operation)," and RG 1.123, "Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants," in the acceptance criteria. In addition, the requirements of GDC 60 and 64 may be met by using the guidance contained in the following RGs and industrial standards:

- RG 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," as it relates to the CMS quality group classification that may contain radioactive materials but is not part of the reactor coolant pressure boundary and is not important to safety

- RGs 1.33 and 1.123 as they relate to the QA programs for the CMS components that may contain radioactive materials

- The Heat Exchanger Institute's "Standards for Steam Surface Condensers," 6th Edition, as they relate to the CMS components that may contain radioactive materials

The CMS is a non-safety-related system located in the turbine building. All piping is designed to ANSI B31.1 standards and, consistent with the guidance in RG 1.26, the CMS is in Quality Group D as listed in DCD Tier 2, Table 3.2-3. Using liquid ring vacuum pumps, the system establishes and maintains a vacuum in the condenser during startup and normal operation. It also removes noncondensable gases and air from the two condenser shells of the main condenser during plant startup, cooldown, and normal operation and exhausts them into the atmosphere.

The applicant indicated in WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," that the CMS will conform with eighth edition of the Heat Exchanger Institute's "Standards for Steam Surface Condensers." In DCD Tier 2, Section 10.4.2.4, the applicant stated that a performance test will be conducted on each pump in accordance with the "Heat Exchanger Institute Performance Standard for Liquid Ring Vacuum Pumps."

WCAP-15799 stated that RG 1.33 is not applicable, and that RG 1.123 has been withdrawn. RG 1.33 applies only to the operational phase of nuclear power plants. Therefore, the staff will review COL applications to ensure their conformance with RG 1.33 or an acceptable alternative. A COL applicant referencing the AP1000 certified design should demonstrate compliance with RG 1.33 or an acceptable alternative. The applicant includes this COL action as a part of the overall plant QA program for operation, which is discussed in DCD Tier 2, Section 17.4. This approach to QA for operation is similar to the approach taken for QA in the radwaste systems (see Sections 11.2 and 11.3 of this report) because radioactive contaminants can be introduced to the CMS through primary-to-secondary system leakage resulting from steam generator tube leakage. The staff agrees with the applicant that RG 1.123 has been withdrawn and is therefore not applicable to the AP1000 CMS.

Provisions 3 and 5 of the specific acceptance criteria in the SRP recommend a discussion on the potential for explosive mixtures and provide specific guidance for the system if the potential exists. DCD Tier 2, Section 10.4.2.2.1, states that the potential for explosive mixtures within the CMS does not exist.

The MSSS and steam generator BDS radiation devices provide early detection of concentrated levels of radioactivity. In addition to this monitoring, the TDS provides radioactive effluent monitoring equipment at the combined exhaust of the CMS and the GSS. The plant operator may secure the discharge of the radioactive effluent upon detection of a high radioactivity level. Although the design has radioactivity monitors in the system to detect leakage into and out of the main condenser during normal operation, startup, and shutdown, the main condenser has no radioactive contaminants inventory. Radioactive contaminants can only be obtained through primary-to-secondary system leakage resulting from steam generator tube leaks. Because the above systems continuously monitor and detect the radioactivity leakage into and out of the condenser and the operator can control the discharge, GDC 60 and 64 are met with respect to the control and monitoring of radioactivity releases to the environment. Section 11.5 of this report discusses the radiological monitoring capabilities of the AP1000 design.

As discussed above, the NRC staff reviewed the design of the CMS in accordance with Section 10.4.2 of the SRP, and finds the system conforms to GDC 60 and 64 and is therefore acceptable.

10.4.3 Turbine Gland Seal System

The staff reviewed the design of the GSS in accordance with Section 10.4.3 of the SRP, "Turbine Gland Sealing System." Acceptability of the design of the GSS is based on meeting the following GDC as described in the SRP:

- GDC 60, as it relates to the GSS design for the control of releases of radioactive materials to the environment

- GDC 64, as it relates to the GSS design for the monitoring of releases of radioactive materials to the environment

The SRP includes RGs 1.33 and 1.123 in the acceptance criteria. In addition, the requirements of GDC 60 and 64 may be met by using the guidance contained in the following RGs:

- RG 1.26, as it relates to the CMS quality group classification that may contain radioactive materials but is not part of the reactor coolant pressure boundary and is not important to safety

- RGs 1.33 and 1.123, as they relate to the QA programs for the CMS components that may contain radioactive materials

The GSS is a non-safety-related system designed to prevent air leakage into and steam leakage out of the casings of the turbine generator. The system returns condensed steam to the condenser and exhausts noncondensable gases into the atmosphere. The system is designed to detect the presence of radioactive contamination in the gas exhaust. The system consists of a steam supply header, steam drains/noncondensable gas exhaust header, two motor-driven gland steam condenser blowers, gland seal condenser, vent and drain lines, and associated piping, valves, and controls. The GSS serves no safety-related function and, consistent with the guidance in RG 1.26, is in the Quality Group D, as listed in DCD Tier 2, Table 3.2-3.

During the initial startup phase of turbine generator operation, steam is supplied to the GSS from the auxiliary steam header supplied from the auxiliary boiler. At times other than initial startup, GSS steam is supplied from either the auxiliary steam system or from the main steam system. The GSS is tested in accordance with written procedures during the initial testing and operation program. The turbine vendor provides testing procedures for the system in its equipment instruction manuals. During normal operation, the monitoring of essential parameters will demonstrate the satisfactory operation of the system components. Pressure and temperature indicators with alarms are provided for monitoring the operation of the system. A pressure controller is provided to maintain steam-seal header pressure by providing signals to the steam-seal feed valve. The gland seal condenser is monitored for shell-side pressure and internal liquid level. The TDS provides a radiation detector with an alarm.

WCAP-15799 stated that RG 1.33 is not applicable, and that RG 1.123 has been withdrawn. RG 1.33 applies only to the operational phase of nuclear power plants. Therefore, the staff will review COL applications to ensure their conformance with RG 1.33 or an acceptable alternative. A COL applicant referencing the AP1000 certified design should demonstrate compliance with RG 1.33 or an acceptable alternative. The applicant includes this COL action as a part of the overall plant QA program for operation, which is discussed in DCD Tier 2, Section 17.4. This approach to QA for operation is similar to the approach taken for QA in the radwaste systems (see Sections 11.2 and 11.3 of this report) because radioactive contaminants can be introduced to the GSS through primary-to-secondary system leakage resulting from steam generator tube leakage. The staff agrees with the applicant that RG 1.123 has been withdrawn and is therefore not applicable to the AP1000 GSS.

The mixture of noncondensable gases discharged from the gland steam condenser blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage resulting from a steam generator tube leak, it is possible for the mixture discharged to be radioactively contaminated. The discharge line vents to the TDS, which contains a radiation monitor for the detection of radioactivity. Upon detection of unacceptable levels of radiation, operating procedures are implemented. Section 11.5 of this report discusses the radiological monitoring capabilities of the AP1000 design. Because the above systems continuously monitor and detect the radioactivity, and because operating procedures may be implemented to control unacceptable levels of radiation, GDC 60 and 64 are met with respect to the control and monitoring of radioactivity releases to the environment.

As discussed above, the staff reviewed the design of the GSS in accordance with Section 10.4.3 of the SRP. The system conforms to GDC 60 and 64 and is therefore acceptable.

10.4.4 Turbine Bypass System

The staff reviewed the design of the turbine bypass system in accordance with Section 10.4.4 of the SRP. The acceptability of the system design is based on meeting the following GDC as described in the SRP:

- GDC 4, as it relates to the system being designed such that a failure of the system (due to a pipe break or system malfunction) does not adversely affect safety-related systems or components

- GDC 34, as it relates to the ability to use the turbine bypass system for shutting down the plant during normal operations by removing residual heat without using the turbine generator

The turbine bypass system, which is also called the steam dump system, provides the capability to direct main steam in a controlled manner from the steam generators bypassing the turbine to the main condenser to dissipate heat and to minimize transient effects on the reactor coolant system (RCS) during startup, hot shutdown, cooldown, and step-load reductions in generator loads.

The turbine bypass system consists of a manifold connected to the main steamlines located upstream of the turbine stop valves and lines from the manifold, with regulating valves, to each condenser shell. The turbine bypass valves are globe valves and are electropneumatically operated. The bypass valves will fail to a closed position upon loss of air or electrical signal. A modulating position responds to the electrical signal from the control system and provides the appropriate air pressure to the valve actuator for modulating the valves open.

Solenoid valves located in the air line to each bypass valve actuator open and close the bypass valve and serve as protective interlocks for bypass valve actuation for tripping the valve open or closed. Two of the blocking solenoid valves for each turbine bypass valve are redundant and prevent bypass valve actuation upon low RCS average temperature (T_{avg}). This minimizes the possibility of excessive RCS cooldown. However, the a low T_{avg} block can be manually bypassed for two of the bypass valves to allow operation during plant cooldown. Another blocking solenoid valve prevents actuation of the bypass valve when the condenser is not available.

The turbine bypass system has two modes of operation, (1) T_{avg} control and (2) pressure control modes. DCD Tier 2, Section 10.4.4.3 discusses the system operation. The design basis of the turbine bypass system is to eliminate challenges to the main steam power-operated relief valves, main steam safety valves, and pressurizer safety valves during a reactor trip from 100 percent power or a 100 percent load rejection, or a turbine trip from 100 percent power without a reactor trip. The turbine bypass system meets its power generation design basis with its ability to bypass 40 percent of the full-load main steam flow to the main condenser. The system's total flow capacity, in combination with bypass valve response time, RCS design, and reactor control system response, is sufficient to meet its design basis.

For load rejections greater than 10 percent but less than 50 percent, or a turbine trip from 50 percent power or less, the turbine bypass system operates with the NSSS control systems to meet the design-basis requirements for heat removal. For power changes less than or equal to a 10 percent change in electrical load, the turbine bypass system is not actuated. The total power change is handled by the power control, the pressurizer level and pressure control, and the steam generator level control systems. Therefore, the staff concludes that the system is designed to enable sufficient steam to be bypassed to the main condenser so that the plant can be shutdown during normal operation without using the turbine generator. The system therefore meets GDC 34 of Appendix A to 10 CFR Part 50 with respect to the ability to use the system for shutting down the plant during normal operations.

In DCD Tier 2, Section 10.4.4.5, the applicant stated that the turbine bypass valves will be tested for operability and the system will by hydrostatically tested to confirm leak tightness before the turbine bypass system is placed in service. The bypass valves may be tested while the unit is in operation. System piping and valves are accessible for inspection. The turbine bypass system except for the turbine bypass valves does not require ISI and testing.

The failure of a turbine bypass high-energy line will not disable the turbine speed control system. The turbine speed control system is designed such that its failure will cause a turbine trip. If the bypass valves fail open, an additional heat load is placed on the condenser. If this load is great enough, the turbine is tripped on high condenser pressure. Turbine rupture discs provide ultimate overpressure protection for the condenser. If the bypass valves fail closed, the power-operated relief valves permit a controlled cooldown of the reactor. DCD Tier 2, Chapter 15 addresses the effects of credible single failures of the turbine bypass system on the NSSS.

The high-energy lines of the turbine bypass system are located in the turbine building, which is a nonseismic category building. No safety-related equipment is located within the turbine building or near the turbine bypass system. Therefore, the staff concludes that the turbine bypass system complies with the requirements of GDC 4 regarding the adverse effects of a pipe break or malfunction on those components of the system necessary for shutdown or accident prevention or mitigation because such components do not exist in the turbine building.

The turbine bypass system includes all components and piping from the branch connection at the main steam system to the main condensers. The scope of review of the turbine bypass system for the AP1000 design included layout drawings, P&IDs, and descriptive information for the turbine bypass system and the auxiliary supporting systems that are essential to its operation.

The basis for accepting the design, design criteria, and design bases of the turbine bypass system is their conformance to GDC 4 and 34 of Appendix A to 10 CFR Part 50 as explained below:

- The AP1000 design meets the requirements of GDC 4 with respect to the system's ability to allow a safety shutdown despite a failure of the turbine bypass system.

- The AP1000 design meets the requirements of GDC 34 with respect to the ability to use the turbine bypass system to shut down the plant during normal operations. The turbine bypass system is designed such that sufficient steam can be bypassed to the main condenser so that the plant can be shutdown during normal operations without using the turbine generator.

Based on the above, the staff concludes that the design of the turbine bypass system conforms to Section 10.4.4 of the SRP and meets the requirements of GDC 4 and 34.

10.4.5 Circulating Water System

The NRC staff reviewed the CWS in accordance with Section 10.4.5 of the SRP. Acceptability of the system as described in the DCD, is based on meeting the requirements of GDC 4, as they relate to provisions in the AP1000 design to accommodate the effects of discharging water that may result from a failure of a component or piping in the CWS. Compliance with GDC 4 is based on meeting the relevant acceptance criteria specified in the SRP, such as the following requirements:

- means to prevent, detect, and control flooding of safety-related areas due to leakage from the CWS

- means to prevent adverse effects of malfunction or failure of CWS piping on functional capabilities of the safety-related systems or components

- control of water chemistry, corrosion, and organic fouling in the CWS

The CWS is a non-safety-related system designed to provide a continuous cooling water supply to the main condenser, the heat exchangers of the turbine building closed cooling water system (TCS), and heat exchangers for the condenser vacuum pump seal water under all modes of power operation and design weather conditions. The system consists of three, $33^1/_3$-percent-capacity circulating water (CW) pumps (mounted in an intake structure), one hyperbolic natural-draft cooling tower, and associated valves, piping, and instrumentation. Since the design of the CWS may vary from site to site, DCD Tier 2, Section 10.4.5.2.1 states that the CWS and cooling tower are subject to site-specific modification or optimization. The COL applicant will determine the final system configuration. DCD Tier 2, Table 10.4.5-1 provides CWS design data based on a conceptual design.

The DCD states that the reference design has been evaluated to verify that postulated CWS failures have no adverse impact on any safety-related SSCs. A postulated CWS line break in the yard area or a failure of the cooling tower basin has no detrimental effect on safety-related SSCs. The cooling tower will be located sufficiently distant from the nuclear island structures so that its postulated collapse does not affect equipment, components, or systems required for safe shutdown of the plant. The site is graded to drain water away from the seismic Category I structures. The seismic Category I structures below grade are protected from flooding by waterproofing systems and water stops. The COL applicant is responsible for determining the system configuration and may modify the design to meet site-specific requirements.

The cooling tower, which serves as a heat sink for the CWS, is site specific in its description; the DCD provides a reference design using a hyperbolic natural draft structure. The cooling tower cools circulating water by discharging the water over a network of baffles in the tower. The water then falls through fill material to the basin beneath the tower, so that heat is rejected to the atmosphere. The cooling tower basin serves as a storage facility for the circulating water inventory and allows the cooling tower to be bypassed during cold weather operations. The bypass is used only during plant startup in cold weather, or to maintain the CWS temperature above 4.4 °C (40 °F) while operating at partial load during periods of cold weather. The raw water system supplies makeup water to the cooling tower basin for the water losses in the CWS. The makeup and blowdown control valves regulate the makeup to and blowdown from the CWS.

In DCD Tier 2, Table 10.4.5-1, the applicant specifies that the circulating water temperature from the cooling tower to the condenser is 32.2 °C (90 °F) when the wet bulb temperature is at 26.7 °C (80 °F) during limiting site conditions. Because the water temperature in the cooling tower varies with weather conditions, the circulating water temperature to the condenser will change accordingly. Higher circulating water temperature results in increased pressure in the condenser due to a decreased rate of steam condensation. Site-specific analysis will accommodate specific site conditions that exceed the wet bulb temperature of 26.7 °C (80 °F) and will be used to adjust cooling system capability.

Three CW pumps take suction from the CW intake structure and circulate the water through the TCS, the condenser vacuum seal water heat exchangers, and the tube side of the main condenser and discharge to the cooling tower. The underground portion of the CWS piping is concrete pressure pipe; the rest is carbon steel pipe that is coated with a corrosion preventive compound inside the pipe. DCD Tier 2, Section 10.4.5.2.2 states that the CWS piping, expansion joints, butterfly valves, condenser water boxes, and tube bundles are designed for a maximum pump discharge pressure of 414 kPa (60 pounds per square inch gauge (psig)).

The effects of flooding due to a CWS failure, such as a rupture of an expansion joint, will not result in detrimental effects on safety-related equipment because the turbine building does not house safety-related equipment. A small CWS leak in the turbine building will drain into the waste water system. A large CWS leak due to pipe failure will be indicated in the control room by a gradual loss of vacuum in the condenser shell. The base slab of the turbine building is located at grade elevation. Water from a system rupture will run out of the building through a relief panel in the west wall of the turbine building reference plant before the water level could rise high enough to cause damage.

Circulating water chemistry is maintained by the turbine island chemical feed system and controlled by the cooling tower blowdown and chemical addition. The chemicals can be divided into six categories based on whether they are a biocide, algicide, pH adjustor, corrosion inhibitor, scale inhibitor, or a silt dispersant. Site water conditions will determine the use of these specific chemicals. The COL applicant will determine the use of the specific chemicals in the CWS chemistry control. (See Section 10.5 of this report for COL action items.)

In DCD Tier 2, Section 10.4.5.2.3, the applicant states that when the condenser is not available due to a malfunction of the CW pumps, cooling tower, or the CW piping, cooldown of the reactor may be accomplished by using the power-operated atmospheric steam relief valves or safety valves, rather than the turbine bypass system. The staff concurs with this alternate cooldown method because the turbine bypass system will not function during accident conditions and the CWS is not required for safe shutdown following an accident.

On the basis of its review, the staff concludes that the design of the CWS meets the requirements of GDC 4, with respect to the effects of discharging water that may result from a failure of a component or piping in the CWS. Acceptance is based on the following design provisions:

- The CWS is designed to prevent flooding of safety-related areas so that the intended safety function of a system or component will not be precluded due to leakage from the CWS.

- The CWS is designed to detect and control flooding of safety-related areas so that the intended safety function of a system or component will not be precluded due to leakage from the CWS.

- Malfunction of a component or piping of the CWS, including an expansion joint, will not have unacceptable adverse effects on the functional performance capabilities of safety-related systems or components.

Therefore, the staff concludes that the design of the CWS meets the guidelines of SRP 10.4.5.

10.4.6 Condensate Polishing System

The staff reviewed DCD Tier 2, Section 10.4.6, "Condensate Polishing System," in accordance with Section 10.4.6, "Condensate Cleanup System," of the SRP. The condensate polishing system (CPS) is acceptable if it prevents adverse chemistry conditions that could degrade the primary coolant boundary integrity. The CPS does not perform any safety-related function.

The CPS is used to remove corrosion products and ionic impurities from the condensate system during plant startup, hot standby, power operation with abnormal secondary cycle chemistry, safe shutdown, and cold shutdown operations.

The major components of the CPS include the following:

- deep bed mixed resin polisher
- resin trap
- spent resin trap
- resin addition hopper and eductor

One-third of the condensate is directed to one of two polishing vessels which are piped in parallel. A second polisher is on standby or in the process of being cleaned, emptied, or refilled. The two polishing vessels contain mixed-bed, ion exchange resin with a strainer installed downstream of each vessel. The strainers are used to prevent the release of resin beads into the feed system.

The staff evaluated the design and operational requirements of the CPS and concluded that it meets the intended function of maintaining secondary coolant quality by including the necessary components to remove dissolved and suspended impurities which may be present in the condensate during normal operation and anticipated operational occurrences.

The staff's review has determined that while the CPS does not serve any safety-related function, its design is acceptable in meeting the intended function of maintaining secondary coolant quality by including the necessary components to remove dissolved and suspended impurities which may be present in the condensate.

10.4.7 Condensate and Feedwater System

The staff reviewed the condensate and feedwater system (CFS) in accordance with Section 10.4.7, "Condensate and Feedwater System," of the SRP. Conformance with the acceptance criteria of the SRP forms the basis for concluding that the CFS satisfies the following criteria:

- GDC 2, with respect to withstanding the effects of natural phenomena (such as earthquakes, tornados, and floods)
- GDC 4, with respect to withstanding the effects of possible fluid flow instabilities (such as water hammers)
- GDC 44, "Cooling Water," with respect to the capability to transfer heat loads from the reactor system to a heat sink under both normal operating and accident conditions
- GDC 45, "Inspection of Cooling Water System," with respect to permitting periodic ISI of systems, components, and equipment
- GDC 46, "Testing of Cooling Water System," with respect to design provisions to permit functional testing of the system and components for structural integrity and leaktightness

The CFS provides a continuous feedwater supply to the steam generators and is composed of piping and components from the condensate system, main feedwater system, and portions of the steam generator system. The condensate system collects condensed steam from the condenser and pumps the condensate to a deaerator. The deaerator removes dissolved gases from the condensate to provide a source of high-quality heated feedwater supply. A main feedwater line takes suction from the deaerator and supplies heated feedwater to each of the two steam generators during all modes of plant operation.

The CFS contains three, 50-percent-capacity motor-driven condensate pumps and three motor-driven feedwater pumps. Two condensate pumps are required during power operation. The spare condensate pump will start automatically upon loss of one of the normally running condensate pumps and/or low condensate header discharge pressure. The three main feedwater pumps take suction from the associated feedwater booster pumps which draw water from the deaerator storage tank. Westinghouse states in the DCD that the feedwater pump, condensate pump, and the pump control systems are designed so that loss of one booster/main feedwater assembly or one condensate pump does not result in a trip of the turbine generator or reactor.

The safety-related isolation function of the CFS is accomplished by redundant means. A single active component failure of the safety-related portion of the system does not compromise the safety function of the system. DCD Tier 2, Table 10.4.7-1 provides the failure analysis results for those occurrences that lead to reduced heat transfer in the steam generators. DCD Tier 2, Section 15.3 evaluates the loss of all feedwater.

Each main feedwater line to the steam generator contains a feedwater flow element, a main feedwater isolation valve (MFIV), a main feedwater control valve (MFCV), and a check valve. The MFIVs, installed in each of the two feedwater lines outside the containment, are used to prevent uncontrolled blowdown from the steam generators in the event of a feedwater line break. The MFCVs (located in the auxiliary building) are used to control feedwater flow rate to the steam generator during normal operation and to provide a backup isolation to limit high-energy fluid addition through the broken loop in the event of a main steamline break. The feedwater check valves (located outside the containment) provide backup isolation to prevent reverse flow from the steam generators whenever the feedwater pumps are tripped. The check valves prevent blowdown from more than one steam generator in the event of a feedwater line break, while the ESF signal is generated to isolate the MFIV and MFCV.

On the basis of the above discussion, the staff finds that the CFS is capable of supplying sufficient feedwater to the steam generators as required during normal operation. The AP1000 design also incorporates appropriate redundancy for containment and feedwater isolation.

The feedwater system does have a connection with the startup feedwater system, but does not have the safety function to transfer heat under accident conditions and, therefore, GDC 44 is not applicable.

During normal plant operation, as well as during plant upset or accident conditions, possible fluid flow instabilities in the feedwater piping that could occur when flow is entering the steam generator may cause water hammer in the system piping. Generic Safety Issue (GSI) A-1 was raised after the occurrence of various incidents of water hammer in operating plants that involved steam generator feedrings and feedwater piping. The staff reviewed the dynamic effects associated with possible water hammers in the feedwater piping for compliance with the requirements of GDC 4. Acceptance is based on meeting the guidance contained in BTP ASB 10-2, "Design Guidelines for Avoiding Water Hammer in Steam Generators," with respect to feedwater-control-induced water hammer. Specifically, BTP ASB 10-2 recommends that the CFS be designed to achieve the following provisions:

- prevent or delay water draining from the feedring following a drop in steam generator water level
- minimize the volume of feedwater piping external to the steam generator which could pocket steam using the shortest horizontal run of inlet piping to the feedring
- perform tests, acceptable to the NRC, to verify that unacceptable feedwater hammer will not occur and provide test procedures for staff approval
- implement pipe refill flow limits where practical

The applicant states in the DCD that the potential for water hammer in the feedwater line would be minimized by the improved design and operation of a feedwater delivery system with the following features:

- The main feedwater pipe connection on each of the steam generators is the highest point of each feedwater line downstream of the MFIV, and the feedwater lines contain no high point pockets that could trap steam.

- The feedwater enters the steam generator at an elevation above the top of the tube bundle through a feedwater nozzle and below the normal water level by a top discharge feedring.

- The feedwater enters a feedring via a welded thermal sleeve connection and leaves it through nozzles attached to the top of the feedring.

- The feedwater line connected to the steam generator is a short, horizontal or downward sloping feedwater pipe at the steam generator inlet which will help keep the feedring full of water.

- Operational limitations on flow to recover steam generator levels and on early feedwater flow into the steam generator to maintain the feedring full of water will minimize the potential for water hammer occurrence.

DCD Tier 2, Section 5.4.2.2 states that these features will prevent the formation of steam pockets during steam generator low level conditions and will minimize the potential for trapping pockets of steam that could lead to water hammer events. The top discharge of the feedring, through the nozzles, will help to reduce the potential for vapor formation in the feedring. The heated feedwater will reduce the potential for water hammer in the feedwater piping or steam generator feedrings.

The staff reviewed the DCD using the guidance of BTP ASB 10-2 and finds that the cited design features would minimize, but not necessarily eliminate, water hammer occurrence in the AP1000 feedwater system design. DCD Tier 2, Section 14.2 describes the initial test program which includes flow testing to detect possible feedwater hammer in the feedwater piping.

The staff concludes that the CFS design meets the requirements of GDC 4 with respect to testing for water hammer occurrence. Sections 3.5 and 3.6 of this report provides the staff's evaluation of the CFS to conform to GDC 4 with respect the effects of missile and high-energy line breaks on the system.

The staff reviewed the CFS for compliance with the requirements of GDC 2. Compliance with the requirements of GDC 2 is based on adherence to Position C.1 of RG 1.29, for the safety-related portion of the system, and Position C.2 for the non-safety-related portion of the system. The DCD indicates that the CFS is non-safety-related and serves no safety function except for that portion of the feedwater piping routed into containment that requires containment and feedwater isolation. The portion of the feedwater system from the steam generator inlets outward through the containment and up to, and including the MFIVs is safety-related and performs the following safety-related functions:

- automatically isolates the main feedwater flow to the steam generators when it is required to mitigate the consequences of a steamline or feedwater line break

- provides a barrier against the release of containment atmosphere during a loss-of-coolant accident

- serves as a boundary for ensuring that steam generator levels can be maintained when the main feedwater pumps are not available

The safety-related portion of the CFS is required to remain functional after a design-basis accident to provide containment and feedwater isolation. This portion of the system will be designed and tested in accordance with the requirements of Section III of the ASME Code for Class 2 components. This requires the CFS to be seismic Category I and to be protected from wind, tornado, missile, and dynamic effects. The non-safety-related portion of the CFS, from the MFIV inlets to the piping restraints at the interface between the auxiliary building and the turbine building, is designed in accordance with the requirements of Section III of the ASME Code for Class 3 components. This portion is seismic Category I. Therefore, the CFS design is consistent with the guidance of RG 1.29, Position C.1, for safety-related portions and Position C.2 for non-safety-related portions of the system. Based on this review, the staff concludes that the CFS design satisfies the guidance in the SRP for meeting the requirements of GDC 2, as they relate to protecting the system against natural phenomena.

The AP1000 design can be used at either single-unit or multiple-unit sites. Criterion 5 of DCD Tier 2, Section 3.1.1, states that the AP1000 design is a single-unit plant. If more than one unit were built on the same site, none of the safety-related systems would be shared. Should a multiple-unit site be proposed, the COL applicant must apply for the evaluation of the units' compliance with the requirements of GDC 5 with respect to the capability of shared systems and components important to safety to perform their required safety functions. A COL applicant must comply with GDC 5 for a multiple-unit site; therefore, the staff finds that the requirements of GDC 5 are satisfied as they relate to whether shared SSCs important to safety are capable of performing required safety functions.

The DCD states that both the safety-related and non-safety-related portions of the feedwater system are designed and configured to accommodate ISI in accordance with Section XI of the ASME Code. Therefore, GDC 45 is satisfied with respect to permitting periodic ISI of system components and equipment. The DCD also states that the feedwater system is designed so that the active components are capable of limited testing during plant operation. Therefore, GDC 46 is satisfied with respect to design provisions to permit appropriate functional testing of the system and components to assure structural integrity and leak tightness. Section 6.6 of this report provides the NRC staff's evaluation of the CFS with respect to periodic ISI of the system's components and equipment.

On the basis of its review, the staff concludes that the design of the CFS meets the NRC regulations set forth in GDC 2, 4, 44, 45, and 46 and is, therefore, acceptable. The following provides the basis for this conclusion:

- The AP1000 meets the requirements of GDC 2 with respect to the system's ability to withstand the effects of earthquakes by meeting RG 1.29, Position C.1, for the safety-related portion of the system, and RG 1.29, Position C.2 for the non-safety-related portion of the system.

- The AP1000 meets the requirements of GDC 4 with respect to the dynamic effects associated with possible fluid flow instabilities by designing and testing the feedwater system in accordance with the guidance contained in BTP ASB 10-2, thereby eliminating or reducing the possibility of water hammers in the feedwater system.

- The AP1000 does not have to meet the requirements of GDC 44 because the design does not have a safety-related auxiliary feedwater system to provide flow to the steam generator via the feedwater system during accident conditions for decay heat removal.

- The AP1000 meets the requirements of GDC 45 and GDC 46 because the safety-related portions of the system are accessible for inspection and the active components are capable of limited testing during power operation in accordance with the plant's TS.

10.4.8 Steam Generator Blowdown System

The staff reviewed DCD Tier 2, Section 10.4.8, "Steam Generator Blowdown System," in accordance with Section 10.4, "Steam Generator Blowdown System," of the SRP. The steam generator blowdown system (SGBS) is acceptable if it satisfies the following requirements:

- GDC 1, as it relates to the quality standards for system component design, fabrication, erection and testing

- GDC 2, as it relates to the design of system components to withstand the effects of natural phenomena such as earthquakes (i.e., seismic Category I requirements)

- GDC 14, "Reactor Coolant Pressure Boundary," as it relates to the use of secondary water chemistry control to maintain the integrity of the primary coolant boundary material

GDC 1 is met through RGs 1.26 and 1.143, "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants."

DCD Tier 2, Section 3.7, "Seismic Design," discusses the safety-related portion of the SGBS associated with high-energy pipe break location and evaluation. The corresponding section in this report evaluates this portion of the SGBS against GDC 2, ensuring that it is classified as seismic Category I and designed to withstand a safe-shutdown earthquake as delineated in RGs 1.29 and 1.143.

The primary function of the SGBS is to remove secondary-side impurities of the steam generator, thus assisting in maintenance of acceptable secondary-side water chemistry in the steam generators. DCD Tier 2, Section 9.3.4, "Secondary Sampling System," discusses the portion of the SGBS related to secondary water chemistry control. Section 9.3.4 of this report evaluates this portion of the SGBS against GDC 14, ensuring that secondary water chemistry is maintained to avoid corrosion-induced failure of the reactor coolant pressure boundary (RCPB) and that the probability of leakage from a rapidly propagating failure of the RCPB does not increase during the life of the plant.

The SGBS consists of two blowdown trains, one for each SG. A crosstie is provided to process blowdown from both SGs through both heat exchangers during high-capacity blowdown from one SG. The blowdown water is extracted from each SG from a location just above the tubesheet. The blowdown from each SG is cooled by a regenerative heat exchanger, and flow is controlled and pressure reduced by a blowdown flow control valve. To recover the thermal energy, the condensate system provides cooling for the heat exchangers. To recover the blowdown fluid, each blowdown train has an electrodeionization (EDI) demineralizing unit which removes impurities from the blowdown flow. Downstream, two trains combine into a common header that contains a relief valve for overpressure protection for the low-pressure portion of the system. A backpressure control valve maintains pressure in the system between the flow control valve and the backpressure control valve. A pump is provided to drain the secondary side of the SG and for recirculation during low-pressure SG wet layup and cooling operations. System isolation under normal operating and transient conditions is accomplished by two isolation valves which close on actuation of the passive residual heat removal system, containment isolation, or high blowdown system radiation, temperature, or pressure.

During normal operation, the blowdown flowrate varies from a minimum of 0.06 percent to a maximum of about 0.6 percent of the maximum steaming rate. During this time, when impurities are low, the expected blowdown rate is approximately 0.1 percent of the maximum steaming rate (about 114 L/min (30 gpm) total or 57 L/min (15 gpm) per SG), which maximizes the detection sensitivity for condenser tube leakage. In the event of main condenser tube leakage, when the concentration of impurities is high, the blowdown rate is increased to a maximum of approximately 0.6 percent of the maximum steaming rate (about 643 L/min (170 gpm) total or 322 L/min (85 gpm) per SG). Normal operation is to recover the blowdown flow through the condensate system. However, blowdown with high levels of impurities can be discharged to the waste water system.

The staff also reviewed the SGBS as it relates to water chemistry control (i.e., its ability to remove particulate and dissolved impurities from the secondary side of the SG). The components within this system and the continuous high-flow blowdown are designed to control the concentration of impurities. In addition, Section 9.3.4 of this report discusses the NRC staff's evaluation of the secondary sampling system (SSS) further.

Based on the discussion provided by the applicant and the staff evaluation in Section 9.3.4 of this report, the staff determined that the design of the SGBS ensures that secondary water chemistry will be controlled to avoid corrosion-induced failure of the RCPB. In addition, the staff determined that sufficient blowdown flow exists to maintain secondary coolant chemistry during normal operation and anticipated operational occurrences.

Since the SGBS is considered an extension of the primary containment, this system is classified as seismic Category I and Quality Group B from its connection to the SG inside the primary containment, up to, and including, the first isolation valve outside the containment, in accordance with RGs 1.26 and 1.29. In addition, the SGBS downstream of the outer containment isolation valves, up to and including, the piping anchors located at the auxiliary building wall, are designed in accordance with the requirements of Class 3 of Section III of the ASME Code and seismic Category I requirements. Piping downstream of the auxiliary wall anchors is not safety-related and not seismic Category I; nevertheless, the piping and components of this system meet the quality standards of Position C.1.1 of RG 1.143 because (1) the components are designed and tested to the requirements set forth in the codes and standards listed, (2) the materials are compatible with the chemical, physical, and radioactive environment during normal conditions and anticipated operational occurrences, and (3) the foundations and walls housing these components are designed to the criteria for natural phenomena and internal and external man-induced hazards. The NRC staff concludes that by meeting the regulatory positions in RGs 1.26, 1.29, and 1.143, the AP1000 design satisfies GDC 1 and 2 with respect to maintaining the system pressure boundary. Further, the staff determined that the design of the SGBS includes the appropriate components, in addition to an adequate blowdown flow rate, to control the concentration of impurities during normal operation and anticipated operational occurrences. This satisfies GDC 14.

10.4.9 Startup Feedwater System

The AP1000 plant does not have a safety-related auxiliary feedwater system. Instead, a non-safety-related startup feedwater system (SFS) is used to supply feedwater to the steam generators during startup, hot standby, cooldown, and the unavailability of main feedwater pumps. The SFS is not required to supply feedwater under accident conditions, but the system is expected to be available as a non-safety-related first line of defense to provide a source of feedwater in loss of feedwater events. The safety-related passive core cooling system (PXS) will provide safety-grade protection for such events. Therefore, the operation of the SFS will not be credited to mitigate a design-basis accident, as described in DCD Tier 2, Chapter 15.

Because the passive design philosophy departs from current licensing practice, the NRC staff may not require the non-safety-related active SFS to meet all the safety-related criteria specified in Section 10.4.9, "Auxiliary Feedwater System," of the SRP. However, the availability of the system must be ensured when needed for its defense-in-depth roles. Consequently, regulatory oversight measures are considered for those significant non-safety active systems. The staff's review considered whether the design of the startup feedwater system:

- has sufficient redundancy to ensure defense-in-depth functions

- has electric supplies from both normal station alternating current (ac) and onsite non-safety-related ac power supplies that are separated to the extent practicable
- is designed and arranged for conditions or an environment anticipated during and after events to ensure operability, maintenance accessibility, and plant recovery
- is protected against internal flooding and other in-plant hazards, including the effects of pipe ruptures, jet impingement, fires, and missiles
- can withstand the effects of natural phenomena (e.g., earthquakes, tornados, and floods) without the loss of capability to perform required functions
- has an associated QA program
- is included in the design reliability assurance program (DRAP) and is under the scope of the Maintenance Rule (10 CFR 50.65) to ensure proper and effective maintenance, surveillance, and inservice inspection and testing
- has graded safety classifications and graded requirements for instrument and control systems based on the importance to safety of their function and their ability to meet reliability availability missions
- has proper administrative controls for shutdown configurations
- is consistent with guidance in RG 1.29, BTP ASB 10-1, and BTP SRXB 5-1 concerning seismic classification, power diversity, and design of residual heat removal systems
- is consistent with guidance in NUREG-0737, "Clarification of TMI Action Plan Requirement," and NUREG-0611 concerning generic improvements to the startup feedwater system design, TS, and SFS reliability

The SFS has two trains that share common suction and discharge piping. Two parallel startup feedwater pumps are provided with a single pump capable of satisfying the SFS flow demand for decay heat removal. Each of the two trains contains a 100-percent capacity, motor-driven startup feedwater pump.

During normal startup and shutdown operations, the two startup feedwater pumps take suction from the condensate storage tank to supply feedwater to the two steam generators. In the event of loss of offsite power that results in a loss of main feedwater supply, the SFS automatically supplies feedwater to the steam generators to cool down the reactor under emergency shutdown conditions. The startup feedwater pumps automatically start following the loss of main feedwater flow in conjunction with an intermediate low steam generator level setpoint. The startup feedwater flow transmitters also provide a redundant indication of startup feedwater and automatic safeguards actuation input on low flow coincident with a low, narrow-range steam generator level.

Each of the two startup feedwater pumps and their associated instruments and electric valves are powered by the standby source motor control center circuit. The pump discharge isolation valves are motor-operated and are normally closed and interlocked with the startup feedwater pumps. In the event of loss of offsite power, the startup feedwater pumps will be powered by the onsite standby power supply (diesels). If both the normal ac power and the onsite standby ac power are unavailable, these valves will fail "as is." The pump suction header isolation valves are pneumatically actuated. The SFS also has temperature instrumentation in the pump discharge that would permit monitoring of the SFS temperature.

On the basis of the above discussion, the staff finds that the startup feedwater pumps possess diversity in motive power source with an electric supply from both normal station ac and onsite non-safety-related ac power supplies that are separated. Therefore, the staff concludes that the design of the startup feedwater pumps meets the redundancy and power source review criteria.

DCD Tier 2, Chapter 14 describes preoperational testing of the SFS. Each startup feedwater pump is equipped with a recirculation line to the demineralized water storage tank for periodic functional testing. When one pump is being tested, the other pump will remain available for automatic operation. Currently, the standard TS require periodic surveillance tests of the auxiliary feedwater pumps and their associated flow trains for the operation plants. TS 3.7.7 in DCD Tier 2, Section 16.1 was provided for the startup feedwater isolation valves and control valves because they are safety-related. DCD Tier 2, Section 3.9.6 describes the inservice testing program for the SFS.

Item II.E.1.1 of NUREG-0737 recommends that all operating pressurized-water reactors perform auxiliary feedwater system reliability analysis. GSI 124 addresses the use of probabilistic risk assessment (PRA) to evaluate the reliability of the auxiliary feedwater system. SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs," provides the interim position on the reliability assurance program applicable to AP1000 design certification. Accordingly, the applicant performed reliability analysis for the main and startup feedwater systems that was addressed in Appendix C8 of the AP1000 PRA.

The applicant also performed a startup feedwater system component failure analysis, with the results identified in DCD Tier 2, Table 10.4.9-1. This tables list several cases in which startup feedwater flow was not available to the steam generator. The analysis indicates that failure of the startup feedwater supply has no effect on the function of the RCS.

The SFS has no safety-related function other than containment and startup feedwater isolation. The portion of the SFS piping that penetrates the containment from the startup feedwater isolation valve (SFIV) to the connection at the steam generator is safety-related, and is required to perform safety functions, such as containment isolation, steam generator isolation, and feedwater isolation, following a design-basis accident. This portion of the piping is designed in accordance with the requirements of Section III of the ASME Code for Class 2 components and is seismic Category I. The portion of the SFS piping from the SFIV inlets to the pipe restraints at the interface between the auxiliary building and turbine building is non-safety-related and is designed in accordance with Section III of the ASME Code for Class 3 components and is seismic Category I. As specified in DCD Tier 2, Table 3.2-3, other valves and remaining piping of the SFS meet ANSI B31.1 requirements and are classified as Class D.

The startup feedwater line connects directly to the steam generator nozzle rather than via the main feedwater piping. In this design, the main feedwater system and the startup feedwater system are parallel systems. The main feedwater system draws water from the deaerator tank and delivers it to the main feedrings within the steam generator, but the startup feedwater system draws water from the condensate storage tank and delivers it to the startup feedwater nozzle on the steam generator. The design allows main feedwater pumps to deliver water to the startup feed headers but does not allow the startup feed pumps to deliver water to the main feed headers.

The applicant stated that the startup feedwater piping layout includes the same features as the main feedwater piping layout, such as a downward elbow in close proximity to the startup feedwater nozzle on the steam generator; exclusion of high points for limiting void collection; redundant positive isolation to prevent back leakage; and delivery of startup feedwater to the steam generator, independent of feedrings. The startup feedwater system is sized, operated, and has water sources consistent with minimizing the potential for water hammer. The staff finds that Westinghouse considered water hammer prevention in the SFS design change.

Double-valve startup feedwater isolation is provided by the SFIV and the startup feedwater control valve (SFCV) located outside the containment. The SFIV and SFCV are powered from separate Class 1E power sources to provide redundant and independent actuation. DCD Tier 2, Section 10.4.9.1.1 states that the SFCVs and SFIVs are designed to close on an appropriate engineered safety signal (i.e., the startup feedwater isolation signal).

On the basis of its review, the staff concludes that the SFS design meets the review criteria for non-safety systems serving defense-in-depth functions.

10.4.10 Auxiliary Steam System

The auxiliary steam system is a non-safety-related system classified as AP1000 Class E. The system consists of an auxiliary steam system and boiler, pumps, auxiliary boiler deaerator, chemical treatment components, and auxiliary boiler fuel oil components. The current SRP does not include a section specifically addressing the auxiliary steam system. The staff determined that the acceptability of this system will be based on meeting the requirements of GDC 4. In other words, failure of the auxiliary steam system, as a result of a pipe break or malfunction of the system should not adversely affect safety-related systems or components.

The auxiliary steam system supplies steam required by the unit for a cold start of the main steam system and turbine generator. It also provides steam during plant operation for hot water heating. The main steam system supplies the auxiliary steam header during normal operation. The auxiliary boiler provides steam to the header during a plant shutdown. The auxiliary steam boiler has a rated capacity of 49,900 kg/hr (110,000 pounds per hour) of saturated steam at 1,344 kPa (195 psig). The system is protected from overpressure by safety valves on the boiler, boiler deaerator, and auxiliary steam header.

Operational safety features are provided within the system for the protection of plant personnel and equipment. The auxiliary steam system does not interface directly with nuclear process systems. The auxiliary boiler is located in the turbine building, and none of the lines pass through areas where safety-related equipment is located. Therefore, the auxiliary steam system meets the requirements of GDC 4 because failure of the system as a result of a pipe break or malfunction of the system should not adversely affect safety-related systems or components.

Testing of the auxiliary steam system is performed before initial plant operation. Components of the system are monitored during operation to verify satisfactory performance. Testing procedures for the auxiliary steam system are located in the system specification and vendors' equipment instruction manuals, which are not part of the AP1000 design certification review.

On the basis of the above review, the staff finds that the auxiliary steam system meets the requirements of GDC 4 because failure of the auxiliary steam system as a result of a pipe break or malfunction of the system does not adversely affect safety-related systems or components. Therefore, the staff finds the auxiliary steam system acceptable.

10.5 Combined License Action Items

The COL applicant will prepare an erosion-corrosion monitoring program for carbon steel portions of the steam and power conversion systems that contain water or wet steam. This monitoring program will address industry guidelines and the requirements included in GL 89-08. This is COL Action Item 10.5-1.

The COL applicant will submit to the staff for review and approval within 3 years of obtaining a combined license a turbine maintenance and inspection program. Once approved, the COL applicant will then implement this program. The turbine maintenance and inspection program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in DCD Tier 2, Section 10.2.3.6. The COL applicant will have available plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis. This is COL Action Item 10.5-2.

The COL applicant will address the final configuration of the plant circulating water system, including piping design pressure and the cooling tower or other site-specific heat sink. As applicable, the COL applicant will address the acceptable Langelier or Stability Index range; the specific chemicals selected for use in the CWS water chemistry control; and applications of chemical pH adjuster, corrosion inhibitors, scale inhibitors, dispersants, algicides, and biocides to reflect potential variations in site-water chemistry and in micro/macro-biological life forms. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. DCD Tier 2, Section 6.4 addresses the impact of toxic gases on the main control room compatibility. This is COL Action Item 10.5-3.

The COL applicant will address the oxygen scavenging agent and pH adjuster selection for the turbine island chemical feed system. This is COL Action Item 10.5-4.

The COL applicant will address the specific biocide. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. The impact of toxic gases on the main control room compatibility is addressed in Section 6.4. This is COL Action Item 10.5-5.

11. RADIOACTIVE WASTE MANAGEMENT

The AP1000 radioactive waste (radwaste) management systems control the handling and treatment of liquid, gaseous, and solid radwaste. These systems include the liquid radwaste system (WLS), the gaseous radwaste system (WGS), and the solid radwaste system (WSS). The WLS is designed to control, collect, process, store, and dispose of liquid radioactive wastes. The WLS is discussed in Section 11.2 of this report. The WLS contains holdup tanks, process pumps, other processing equipment including monitor tanks, and appropriate instrumentation and controls. Ion exchange is the principal waste treatment process in the WLS.

The WGS collects, processes, and monitors gaseous releases. The WGS is discussed in Section 11.3 of this report. The WGS collects gaseous wastes that are potentially radioactive or hydrogen-bearing (i.e., those wastes resulting from degassing the reactor coolant and the contents of the reactor coolant drain tank (RCDT)), stores them for decay in charcoal delay beds, and subsequently releases them to the environment via the plant vent.

The WSS controls the processing of solid wastes generated during reactor operation, as well as the packaging and storage of such processed wastes before shipment to a licensed disposal facility. The WSS is discussed in Section 11.4 of this report.

The process and effluent radiological monitoring instrumentation and sampling systems, which are discussed in Section 11.5 of this report, detect and measure the radioactive materials in plant liquid and gaseous processes and effluent streams.

11.1 Source Terms

The staff reviewed Design Control Document (DCD) Tier 2, Section 11.1, "Source Terms," in accordance with the guidance and acceptance criteria in Section 11.1, "Source Terms," of the Standard Review Plan (SRP). The following acceptance criteria are provided in Paragraph II of SRP Section 11.1:

- Title 10 of the Code of Federal Regulations (10 CFR) Part 20, as it relates to limits on doses for persons in unrestricted areas

- 10 CFR Part 50, Appendix I, as it relates to the numerical guidelines for design objectives and limiting conditions for operation (LCOs) to meet the "as low as is reasonably achievable" (ALARA) criterion given in Appendix I

- 10 CFR Part 50, Appendix A, General Design Criteria (GDC) 60, as it relates to the radioactive waste management systems' design to control releases of gaseous and liquid radioactive effluents, as well as to handle radioactive solid wastes, produced during normal operation

Use of the following regulatory guides (RGs) meet the requirements of the regulations identified above:

- RG 1.110, as it relates to the cost-benefit analysis for radioactive management systems and equipment

- RG 1.112, as it relates to the method of calculating release of radioactive materials in effluents from nuclear power plants

- RG 1.140, as it relates to the design, testing, and maintenance of air filtration and adsorption units of normal ventilation exhaust systems

The specific criteria sufficient to meet the relevant requirements of 10 CFR Part 20 and 10 CFR Part 50, Appendix I, are as follows:

(1) The parameters used to calculate concentrations of radioactive materials in primary and secondary coolant are consistent with those given in NUREG-0017, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors" (PWR-GALE code).

(2) All normal and potential sources of radioactive effluents delineated in Subsection I of SRP Section 11.1 are considered.

(3) For each source of liquid and gaseous waste considered in Subsection I of SRP Section 11.1, the volumes and concentrations of radioactive material given for normal operation and anticipated operational occurrences (AOOs) are consistent with those given in NUREG-0017.

(4) Decontamination factors (DFs) for in-plant control measures used to reduce gaseous effluent releases to the environment, such as iodine removal systems and high-efficiency particulate air (HEPA) filters for building ventilation exhaust systems and containment internal cleanup systems, are consistent with those given in RG 1.140. The building mixing efficiency for containment internal cleanup is consistent with that in NUREG-0017.

(5) DFs for in-plant control measures used to reduce liquid effluent releases to the environment, such as filters, demineralizers, and evaporators, are consistent with those in NUREG-0017.

(6) Radwaste augments used in the calculation of effluent releases to the environment are consistent with the findings of a cost-benefit analysis and are performed using the guidance of RG 1.110.

(7) Effluent concentration limits at the boundary of the unrestricted area do not exceed the values specified in Table 2 of Appendix B to 10 CFR Part 20.

(8) The source terms result in meeting the design objectives for doses in an unrestricted area, as set forth in Appendix I to 10 CFR Part 50.

(9) The applicant provides in the DCD the relevant information required by 10 CFR 50.34a. This technical information should include all the basic data listed in Appendix B to RG 1.112 needed to calculate the releases of radioactive material in liquid and gaseous effluents. The Gaseous and Liquid Effluent (GALE) computer code, along with the source term parameters given in NUREG-0017, is an acceptable method to perform this calculation.

(10) If the calculational technique or any source term parameter differs from that given in NUREG-0017, the applicant should describe these differences in detail, as well as the bases for the method and parameters used.

In reviewing the AP1000 design against the above criteria, the staff found that some of the above criteria dealt with the source term, which is the subject of this section, while some dealt with the subjects to be discussed in Sections 11.2 through 11.5 of this report. In request for additional information (RAI) 460.002, the staff asked the applicant to identify the relevant DCD sections that address the above criteria. The following are the applicant's responses and the staff's evaluation of these responses:

- The applicant stated that DCD Tier 2, Table 11.1-1, "Parameters Used in the Calculation of Design Basis Fission Product Activities," DCD Tier 2, Table 11.1-7, "Parameters Used to Describe Realistic Sources," and DCD Tier 2, Section 11.1.3 address Criterion 1. The staff reviewed the parameters in these tables and confirmed that they are consistent with those given in NUREG-0017. Therefore, the staff finds Criterion 1 to be satisfied.

- The applicant stated that DCD Tier 2,Table 11.2-6, "Input Parameters for the GALE Computer Code," addresses Criteria 2 through 4. The staff reviewed DCD Tier 2, Table 11.2-6, and DCD Tier 2, Sections 11.2 and 11.3, and found that all sources of radioactive effluents delineated in Subsection I of SRP Section 11.1 were considered, and that the sources are consistent with NUREG-0017. In addition, the DFs used for gaseous effluents and HEPA filter efficiency are consistent with RG 1.140. Therefore, the staff finds that Criteria 2 through 4 are satisfied.

- The applicant stated that DCD Tier 2, Table 11.2-5, "Decontamination Factors," and DCD Tier 2, Table 11.2-6 address Criterion 5. The staff reviewed these two tables and confirmed that the DFs for liquid effluents, such as filters, demineralizers, and evaporators, are consistent with NUREG-0017. Therefore, the staff finds that Criterion 5 is satisfied.

- The applicant stated that Criterion 6 is not applicable to the AP1000 radwaste systems because radwaste augments are not assumed as part of the licensing basis. The staff agrees.

- The applicant stated that DCD Tier 2, Table 11.2-8, "Comparison of Annual Average Liquid Release Concentrations with 10 CFR 20 for Expected Release Effluent Concentration Limits," and DCD Tier 2, Table 11.3-4, "Comparison of Calculated Offsite

Airborne Concentration with 10 CFR 20 Limits," address Criterion 7. Based on the evaluation in Sections 11.2.1 and 11.3.1 of this report, the staff finds the release concentrations acceptable.

- The applicant stated that DCD Tier 2, Sections 11.3.3.1 and 11.3.3.4 address Criterion 8 regarding the doses in an unrestricted area, and meet Appendix I to 10 CFR Part 50. The staff's evaluation is included in Sections 11.2.1 and 11.3.1 of this report. This evaluation led to combined license (COL) Action Items 11.2-2 and 11.3-1.

- The applicant stated that Criterion 9 is met because the GALE computer code is used, and that RG 1.112, Appendix B, is satisfied. Since the GALE code is used, with the NUREG-0017 source terms parameters, as indicated above, the staff finds that Criterion 9 is satisfied.

- The applicant stated that Criterion 10 is not applicable because NUREG-0017 is used for AP1000. The staff agrees.

In Sections 11.2 and 11.3 of this report, the staff evaluated the potential radioactive wastes and the capability of the WLS and WGS to keep radioactive effluents in unrestricted areas ALARA, in accordance with the requirements of 10 CFR Part 50, Appendix I. In addition, Sections 11.2 and 11.3 of this report document the staff's evaluation of compliance with 10 CFR 20.1302, which defines the criteria for radionuclide concentration limits in liquid and gaseous effluents released into unrestricted areas. Sections 11.2 through 11.5 of this report discuss compliance with GDC 60, as it relates to the design of the radioactive waste management systems to control releases of radioactive materials and to conform with the guidance in RGs 1.110 and 1.140. As discussed above, RG 1.112 is satisfied by meeting Criterion 9.

DCD Tier 2, Section 11.1 describes the sources of radioactivity that are generated within the core and have the potential of leaking to the reactor coolant system (RCS) during normal plant operation, including AOOs, by way of defects in the fuel cladding. Two source terms are presented for the primary and secondary coolant. The first is the design-basis source term, which assumes a design-basis fuel defect level of 0.25 percent. Reactor coolant activity is determined based on time-dependent fission product core inventories that are calculated by the ORIGEN code. The first source term serves as a basis for radwaste system design and shielding requirements, and is listed in DCD Tier 2, Tables 11.1-2, 11.1-3, 11.1-5, and 11.1-6. The second source term is a realistic model which represents the expected average concentrations of radionuclides in the primary and the secondary coolant. These values are determined using the model in American National Standards Institute (ANSI)-18.1 and the PWR-GALE code (NUREG-0017, Revision 1). The realistic source term provides the bases for estimating typical concentrations of the principal radionuclides, as listed in DCD Tier 2, Table 11.1-8. This source term model reflects the industry experience at a large number of operating PWR plants.

The NRC staff found that the assumption of a 0.25 percent fuel defect level used for the AP1000 design-basis source term deviates from the fuel defect assumption of 1.0 percent described in SRP Sections 11.2 and 11.3 for the WLS and the WGS. The applicant provided fuel leak data for operating plants in a letter dated June 17, 1997, to demonstrate that the 0.25 percent fuel defect level was an appropriate assumption. The staff independently reviewed the fuel data for the applicant's fuel and found the data were applicable to the AP1000 to justify the 0.25 percent fuel failure assumption. Furthermore, Technical Specification (TS) (LCO) 3.4.11, "RCS Specific Activity," specifies dose limits for iodines and noble gases corresponding to a fuel defect level of 0.25 percent, to ensure that plant operation remains within the limits consistent with the design assumptions. In RAI 460.001, the staff requested the applicant to justify the fuel defect level assumption used specifically for the AP1000. Based on the applicant's response to RAI 460.001, the staff confirmed that the justifications were applicable to the AP1000 fuel.

The staff reviewed the recent fuel data for Westinghouse fuel and compared the data with independent information available to the staff. Based on the results of the comparison, the staff agrees with the applicant that for Westinghouse 17 x 17 Vantage 5 Hybrid (V5H) fuel, the 0.25 percent fuel failure assumption is reasonable. Therefore, the staff finds that the deviation from the fuel defect assumption from the SRP is acceptable for the AP1000.

Based on the above evaluation, the staff finds that the source terms described in DCD Tier 2, Section 11.2 for the AP1000 are acceptable. Sections 11.2 through 11.5 of this report address the issues identified above.

11.2 Liquid Waste Management System

11.2.1 System Description and Review Discussion

The staff reviewed DCD Tier 2, Section 11.2, "Liquid Waste Management System," in accordance with the guidance and acceptance criteria described in SRP Section 11.2. Paragraph II of SRP Section 11.2 provides the following acceptance criteria for the WLS:

- 10 CFR 20.1302, as it relates to limits on doses to persons in unrestricted areas
- 10 CFR 50.34a, as it relates to the inclusion of sufficient design information to demonstrate the design objectives for equipment necessary to control releases of radioactive effluents to the environment
- GDC 60, as it relates to the design of liquid waste management systems to control releases of liquid radioactive effluents
- GDC 61, as it relates to the design of liquid waste management systems to ensure adequate safety under normal and postulated accident conditions

The relevant requirements of the regulations identified above are met by using the regulatory positions contained in the following RGs:

- RG 1.110, as it relates to performing a cost-benefit analysis for reducing cumulative dose to the population by using available technology

- RG 1.143, as it relates to the seismic design and quality group classification of components used in the liquid waste management system and the structures housing this system, as well as the provisions used to control leakages

- 10 CFR Part 50, Appendix I, Sections II.A and II.D, as they relate to the numerical guidelines for dose design objectives and LCOs to meet the ALARA criterion

DCD Tier 2, Section 11.2 describes the WLS design to control, collect, process, store, and dispose of liquid radioactive waste generated as the result of normal operation, including AOOs. The WLS, shown in DCD Tier 2, Figures 11.2-1 and 11.2-2, consists of tanks (effluent holdup tanks, waste holdup tanks, chemical waste tanks, and monitor tanks), pumps, ion exchangers, and filters. The design data for these components are listed in DCD Tier 2, Table 11.2-2.

The WLS processes the following four major categories of radioactively contaminated wastes:

(1) borated waste water from the RCS effluents released through the chemical and volume control system (CVS), primary sampling system sink drain, and equipment leakoffs and drains

(2) floor drains from various building sumps and equipment drains

(3) detergent waste from hot sinks and showers, and some cleanup and decontamination processes

(4) chemical waste from the laboratory and other relatively small volume sources

The WLS does not normally process nonradioactive secondary system effluent. The steam generator (SG) blowdown system, as described in DCD Tier 2, Section 10.4.8, and the turbine building drain system normally handle secondary system effluents. Radioactivity can enter the secondary systems from SG tube leakage. If significant radioactivity is detected in secondary-side systems, blowdown is redirected to the WLS for processing and disposal in a monitored fashion.

The effluent subsystem processes borated and hydrogen-bearing liquid from the RCS through the CVS and the RCDT. There are two effluent holdup tanks, each with a capacity of 105,992 liters (28,000 gallons). Normally, these wastes are processed through a prefilter, ion exchangers, and an after-filter. The processed waste is then collected in one of the effluent waste monitor tanks, sampled, and discharged (if acceptable). Each of the effluent waste monitor tanks has a capacity of 56,781 liters (15,000 gallons). The processed waste may also be recirculated for further processing by the subsystem. The applicant's estimates of the normal generation rate of these wastes can be found in DCD Tier 2, Table 11.2-1.

A set of four ion exchangers connected in series make up the principal process equipment for treating liquid radwaste from the effluent holdup tanks and the waste holdup tanks. The four ion exchangers have a waste prefilter (upstream of the ion exchangers) and a waste after-filter (downstream of the ion exchangers) and consist of the following:

- one specific ion exchanger (containing activated charcoal on a zeolite resin) that acts as a deep-bed filter and removes oil from floor drain wastes
- one cation bed ion exchanger
- two mixed bed ion exchangers.

Design flexibility exists to manually bypass any of these ion exchangers, as well as to interchange the order of the last two mixed beds, to provide complete usage of the resin. The applicant stated that the media for the ion exchangers will be selected by the COL applicant to optimize system performance. A COL applicant referencing the AP1000 certified design should identify the media it plans to use for the cation bed and the mixed bed ion exchangers in the WLS. DCD Tier 2, Section 11.2.5.3 specifies that the COL applicant will identify the types of liquid waste ion exchange and adsorbent media to be used in the WLS, dependent upon developments in ion exchange technology and specific characteristics of the liquid radwaste to be processed. This is COL Action Item 11.2-3, as identified in DCD Tier 2, Table 1.8-2.

Based on DCD Tier 2, Table 11.2-1, the combined normal generation rate of the liquid wastes serviced by both effluent holdup tanks and the waste holdup tank is 7,287 liters/day (1,925 gallons/day). In RAI 460.004, the staff asked the applicant to provide additional information on the process capacity of the WLS. In its response, the applicant stated that the ion exchanger has a processing capability of 40,882 liters/day (10,800 gallons/day) or 284 liters/minute (75 gallons/minute). This information was incorporated into DCD Tier 2, Section 11.2.1.2.1. This provides an adequate margin for processing surges in the generation rates of all wastes serviced by the two subsystems. The subsystem holdup tanks, which have a capacity of 105,992 liters (28,000 gallons) per tank, have an adequate margin for collecting large increases in the generation of wastes.

The WLS piping permits connection of mobile processing equipment. When liquid wastes are processed by mobile equipment, the treated liquid waste is returned to the WLS for eventual discharge to the environs, or to an ultimate disposal point for liquids that are to be removed from the plant site.

The detergent waste subsystem collects wastes that are generally high in dissolved solids, but low in radioactivity, from plant hot sinks and showers and some cleanup and decontamination processes. The detergent wastes are generally not compatible with the ion exchange resins and are collected in the chemical waste tank. The size of the chemical waste tank (33,690 liters or 8,900 gallons) is adequate. Normally, these wastes are sampled. If the detergent waste activity is below acceptable limits, the waste can be discharged without processing. When detergent waste activity is above acceptable limits and processing is necessary, the waste water may be transferred to a waste holdup tank and processed in the same manner as other radioactively contaminated waste water, if onsite equipment is suitable to do so.

If onsite processing capabilities are not suitable for the composition of the detergent waste, processing can be performed using mobile equipment brought into the radwaste building, or the waste water can be shipped offsite for processing. After processing by the mobile equipment, the water may be transferred to a waste holdup tank for further processing or transferred to a monitor tank for sampling and discharge. The applicant estimates, in DCD Tier 2, Table 11.2-1, that the normal generation rate of these wastes will be 908 liters/day (240 gallons/day) and assumes that the waste will be fully discharged to the environs. The capacity of the limiting processing equipment (i.e., ion-exchanger) is 408,824 liters/day (108,000 gallons/day) in this subsystem. This capacity provides an adequate margin for processing a surge in the generation rate of this waste.

Radioactively contaminated chemical wastes are normally generated at a low rate and collected in the chemical waste tank shared with detergent wastes. Chemicals are added to the tank, as needed, for pH or other chemical adjustment. The design includes alternatives for processing or discharge. These wastes may be processed onsite, without being combined with other wastes, using mobile equipment. When combined with detergent wastes, they may be treated like detergent wastes, as described above. If onsite processing capabilities are not suitable, processing can be performed using mobile equipment or the waste water can be shipped offsite for processing.

SG blowdown is normally processed by the SG blowdown treatment system demineralizers, as discussed in DCD Tier 2, Section 10.4.8. In the AP1000 design, SG blowdown does not normally contribute to any liquid radwaste discharge to the environs. Under normal conditions, the processed blowdown is totally recycled in the plant (i.e., discharged to the condenser hot well). However, if the blowdown flow is detected to be excessively radioactive, it will be manually aligned to the inlet of the waste holdup tank for processing before its eventual discharge to the environment.

Process discharge is normally aligned to one of the three monitor tanks. The release of processed liquid waste from any monitor tank to the environs is permitted only when sampling of the subject tank's contents indicates that such a release is permissible. The effluent discharge line includes a radiation monitor. The discharge flow rate for borated wastes should be preset by the COL applicant to limit the boric acid concentration in the circulating water blowdown stream to an acceptable level, in compliance with local requirements. A COL applicant referencing the AP1000 certified design should identify its planned discharge flow rate for borated wastes. DCD Tier 2, Section 11.2.5.4 states that a COL applicant will determine the rate of discharge and the dilution necessary to maintain an acceptable concentration, in compliance with local requirements. This is COL Action Item 11.2-4, as identified in DCD Tier 2, Table 1.8-2.

When the waste discharge flow is diluted by the circulating water blowdown flow of 22,712 liters/minute (6,000 gallons/minute), the discharge flow rate for any waste stream should be restricted, as necessary, to maintain an acceptable concentration level for radionuclides in liquid effluents discharged into any unrestricted area. The above criterion for liquid waste discharge flow ensures compliance with the 10 CFR Part 20, Appendix B, Table 2, Column 2, limits for concentrations of radionuclides in liquid effluents discharged into any unrestricted area. All WLS discharges are made through a single liquid waste discharge line to the circulating water blowdown stream. The dilution factor provided for the activity released is site dependent and will be provided by the COL applicant (COL Action Item 11.2-4).

All WLS releases are monitored by a radiation monitor prior to dilution and discharge. The monitor is located on the common discharge line downstream of the WLS monitor tanks, in compliance with the 10 CFR Part 20, Appendix B, Table 2, Column 2, limits for radionuclide concentrations in liquid effluents discharged into unrestricted areas. These radiation monitors will provide a signal to terminate liquid radwaste releases to unrestricted areas before the discharge concentration in the line exceeds a predetermined setpoint. As discussed above, the radiation monitors are provided for controlling and monitoring release of radioactive materials from liquid effluents to unrestricted areas, as required by GDC 60. The staff will review the operational setpoints of the subject radiation monitors on a plant-specific basis for each COL application. A COL applicant referencing the AP1000 certified design should identify the planned operational setpoints for its WLS radiation monitors in its plant-specific offsite dose calculation manual (ODCM). DCD Tier 2, Section 11.5.7 provides for a COL applicant to develop an ODCM to address operational setpoints for the radiation monitors, as well as programs for monitoring and controlling the release of radioactive material into the environment, thus eliminating the potential for unmonitored and uncontrolled release. This is COL Action Item 11.5-1, as identified in DCD Tier 2, Table 1.8-2.

The applicant calculated the annual liquid effluent releases (shown in DCD Tier 2, Table 11.2-7) using the PWR-GALE code methodology. DCD Tier 2, Table 11.2-6 provides the standard design parameters for running this computer program to calculate expected primary and secondary coolant radionuclide concentrations and liquid effluents. DCD Tier 2, Table 11.2-2 lists the component data for the WLS. Specifically, the table lists the number of WLS holdup tanks, monitor tanks, pumps, filters, and ion exchangers (and their types), and their design capacities or flow rates, whichever is applicable. DCD Tier 2, Table 11.2-1 lists the collection rates and primary coolant activity fractions of the individual liquid waste streams. DCD Tier 2, Table 11.2-5 lists the DFs for different categories of radionuclides provided by the different types of ion exchangers. DCD Tier 2, Figure 11.2-2 lists the WLS piping and instrumentation drawings (P&IDs). DCD Tier 2, Tables 11.2-7, 11.2-8, and 11.2-9 provide the results of the GALE code. SRP Section 11.2 recommends the GALE code methodology. The staff reviewed the input data and found them to be acceptable.

Because demonstration of specific compliance with 10 CFR Part 50, Appendix I, dose guidelines for liquid effluents is not within the scope of the standard design, the staff will review each compliance demonstration for each COL application. RG 1.110 provides guidance for performing a cost-benefit analysis in order to reduce cumulative dose to the population by using available technology. DCD Tier 2, Section 11.2.5.2 states that the COL applicant will provide a site-specific cost-benefit analysis to address the requirements of 10 CFR Part 50, Appendix I, regarding population doses resulting from the release of liquid effluents. The COL applicant will also demonstrate conformance with RG 1.110, as it relates to performing a site-specific cost-benefit analysis for reducing dose. This is COL Action Item 11.2-2, as identified in DCD Tier 2, Table 1.8-2.

The requirements of 10 CFR 20.1302 permit an applicant to demonstrate compliance with applicable dose limits, in part, by showing that the annual average concentrations of radioactive materials in those liquid effluents to be released into an unrestricted area do not exceed the limits specified in the subject table column. DCD Tier 2, Table 11.2-8 demonstrates that the sum of the ratios of the liquid effluent concentrations of radionuclides in any unrestricted area to the liquid effluent concentration limits for the respective radionuclides given in 10 CFR Part 20, Appendix B, Table 2, Column 2, are well below 1.0 percent.

In RAI 460.001, the staff asked the applicant to justify its assumption of a 0.25 percent fuel defect level. This assumption deviates from the fuel defect assumption of 1.0 percent in SRP Section 11.2 for the liquid waste management system. The applicant provided justification for this deviation in its response to RAI 460.001. For the reasons set forth in Section 11.1 of this report, the staff finds this deviation acceptable.

In addition, the applicant explained that for the maximum release concentration, DCD Tier 2, Table 11.2-9 sets forth results, assuming a maximum defined fuel defect level, that correspond to a 1.0 percent fuel defects for all fission product nuclides, except iodine and noble gas. For iodine and noble gas, the TS limits corresponding to a 0.25 percent fuel defect level were assumed. The results in DCD Tier 2, Table 11.2-9 demonstrate that the sum of the ratios of the liquid effluent concentrations of radionuclides in any unrestricted area to the liquid effluent concentration limits for the respective radionuclides given in 10 CFR Part 20, Appendix B, Table 2, Column 2, is 0.53 percent. This value is below 1.0 percent and provides for a sufficient margin before reaching the maximum defined fuel defect level. Therefore, compliance with 10 CFR 20.1302 is demonstrated by the information included in DCD Tier 2, Table 11.2-9. In addition, Criterion 7, which was discussed in Section 11.1 of this report, is met.

The WLS is a non-safety-related system and serves no safety function except system isolation from the containment, when required. The system valves interfacing with the containment, which serve the above safety function, are safety-related and seismic Category I, as shown in DCD Tier 2, Table 3.2-3. In DCD Tier 2, Table 3.2-3, the applicant indicated that the WLS is located in the seismic Category I auxiliary building. All waste collection and waste monitor tanks, the chemical waste tank, and the condensate storage tank are equipped with level indication and provisions for high-level alarms in the control room. Local indication and controls are available on portable displays which may be connected to the data display and processing system.

The staff reviewed DCD Tier 2, Section 11.2 and Appendix 1A for conformance with RG 1.143, "Design Guidance for Radwaste Management Systems, Structures, and Components Installed in Light Water-Cooled Nuclear Power Plants." In Appendix 1A, the applicant committed to comply with all the positions in RG 1.143, with one exception relating to Criterion C.6.2.1. In RAI 460.003, the staff pointed out that the AP1000 conforms with Criterion C.6.2.1 based on DCD Tier 2, Section 3.7.2, which states that the radwaste building of the AP1000 is designed to Uniform Building Code—1977. In response to RAI 460.003, the applicant agreed with the staff and revised DCD Tier 2, Appendix 1A, to be consistent with DCD Tier 2, Section 3.7.2. Therefore, AP1000 conforms to RG 1.143.

The tanks of the WLS (effluent holdup tanks, waste holdup tanks, monitor tanks, and chemical waste tank) are located in the auxiliary building which is designed to seismic Category I criteria. The other components, such as ion exchangers, filters, degasifier, pumps, applicable valves, and heat exchangers, are also in the auxiliary building. All WLS tank overflows are routed to a watertight room within the auxiliary building and drained to the auxiliary building sump, which is pumped to a waste holdup tank. Since the auxiliary building is designed to seismic Category I criteria, the staff finds the WLS to be acceptable with respect to meeting the seismic design guidance specified in RG 1.143.

Components (such as heat exchangers, pumps, tanks, degasifier, ion exchangers, filters, and valves) in the WLS are nonseismic and are classified as AP1000 Class D (i.e., Quality Group D in RG 1.26), as shown in DCD Tier 2, Table 3.2-3. The quality assurance (QA) program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall QA program described in DCD Tier 2, Chapter 17. DCD Tier 2, Section 17.5 states that the COL applicant will address its design phase QA program, as well as its QA program for procurement, fabrication, installation, construction and testing of structures, systems and components in the facility. The evaluation of the overall QA program is in Chapter 17 of this report. As set forth in Chapter 17 of this report, a COL applicant will address these matters pursuant to COL Action Item 17.5-1, and the staff will review them in the context of the COL application. The staff finds the WLS acceptable with respect to meeting the QA guidance specified in RG 1.143, provided that the overall QA program described in any particular COL application is acceptable.

The liquid waste system is designed to handle most liquid effluents and other anticipated events using installed equipment. However, for events occurring at a very low frequency, or producing effluents not compatible with the installed equipment, temporary equipment may be brought into the radwaste building mobile treatment facility truck bays. Connections are provided to and from various locations in the liquid waste system to facilitate connections with mobile equipment. This allows the mobile equipment to be used in series with installed equipment, as an alternative to the treated liquids returning to the liquid waste system, or as an ultimate disposal point. The staff will review any mobile processing equipment that may be used for processing liquid radwaste on a plant-specific basis for particular COL applications using the guidelines of RG 1.143. The COL applicant should discuss how any mobile processing equipment intended for use in the processing of liquid radwaste meets the guidelines of RG 1.143. DCD Tier 2, Section 11.2.5.1 addresses this COL action item. By meeting the guidance in RG 1.143 and RG 1.110, the WLS, with the exception of this COL action item, meets the requirements of GDC 61, as specified in SRP Section 10.2. This is COL Action Item 11.2-1, as identified in DCD Tier 2, Table 1.8-2.

The NRC Inspection Enforcement Bulletin (IEB) 80-05, "Vacuum Condition Resulting in Damage to Chemical Volume Control System (CVCS) Holdup Tanks (sometimes called 'Clean Waste Receiver Tanks')," addresses issues concerning the release of radioactive material or other adverse effects as a result of low-vacuum conditions causing tank buckling. The low-vacuum condition could be created by the cooling of hot water in a low-pressure tank. Except for the RCDT located in the containment building, no other tank in the WLS is exposed to hot water. The RCDT has several design features, including an external design pressure provided in DCD Tier 2, Table 11.2.2, of 204.7 kiloPascals (kPa) (15 pounds per square inch gauge (psig)), which eliminate the possibility of structural collapse of the RCDT resulting from steam condensation. Because of these design features, the RCDT will not collapse even if exposed to a full vacuum. The staff noted that all of the WLS tanks have vents that are adequately sized to prevent tank collapse during drain down. Therefore, the staff finds that the design of the AP1000 WLS adequately addresses the concern identified in IEB 80-05 and is, therefore, acceptable.

11.2.2 Conclusion

For the reasons set forth above, the staff concludes that the design of the WLS is acceptable and meets the requirements of 10 CFR 20.1302; 10 CFR Part 50, Appendix I; 10 CFR 50.34a; GDC 60; and GDC 61. This conclusion is based on the following:

- The AP1000 design has met the dose requirements of 10 CFR 20.1302 by assuring that the annual average concentration of radioactive materials in liquid effluents released into an unrestricted area will not exceed the limits specified in 10 CFR Part 20, Appendix B, Table 2, Column 2.

- The AP1000 design has demonstrate compliance with 10 CFR 50.34a, as it relates to sufficient design information being provided, as set forth in the above discussion.

- A COL applicant referencing the AP1000 certified design will demonstrate compliance with 10 CFR Part 50, Appendix I, requirements for offsite individual doses and population doses resulting from liquid effluents by preparing a site-specific cost-benefit analysis in accordance with RG 1.110 (COL Action Item 11.2-2).

- The AP1000 design has met the requirements of GDC 60 with respect to controlling releases of liquid effluents by radiation monitoring of the WLS releases. All WLS releases are monitored by a radiation monitor, which will generate a signal to terminate liquid radwaste releases before the discharge concentration exceeds a predetermined set point. A COL applicant will identify the operational setpoint for its WLS radiation monitors in its plant-specific ODCM (COL Action Item 11.5-1).

- Compliance with the requirements of GDC 61 is demonstrated by meeting the guidelines of RG 1.143 and RG 1.110 (COL Action Item 17.5-1).

Based on the above review, the staff has determined that the AP1000 WLS design meets the guidelines of SRP Section 11.2 and is therefore acceptable.

11.3 Gaseous Waste Management System

11.3.1 System Description and Review Discussion

The staff reviewed DCD Tier 2, Section 11.3, "Gaseous Waste Management System," in accordance with the guidance and acceptance criteria described in SRP Section 11.3. Paragraph II of SRP Section 11.3 provides the following acceptance criteria for the WGS:

- 10 CFR 20.1302, as it relates to limits on doses to persons in unrestricted areas
- 10 CFR 50.34a, as it relates to providing sufficient design information to demonstrate the effectiveness of design objectives for equipment necessary to control releases of radioactive effluents to the environment
- GDC 3, as it relates to protecting gaseous waste handling and treatment systems from the effects of an explosive mixture of hydrogen and oxygen
- GDC 60, as it relates to the design of radioactive waste management systems to control releases of gaseous radioactive effluents
- GDC 61, as it relates to the control of radioactivity in the WGS and the ventilation systems associated with fuel storage and handling areas
- 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, as they relate to the numerical guidelines for dose design objectives and LCOs necessary to meet the ALARA criterion

The relevant requirements of the regulations identified above are met by using the regulatory positions contained in the following RGs:

- RG 1.140, as it relates to the design, testing, and maintenance of normal ventilation exhaust systems at nuclear power plants
- RG 1.143, as it relates to the seismic design and quality group classification of components used in the gaseous waste management system and the structures housing this system, as well as the provisions used to control leakage
- SRP Branch Technical Position Effluent Treatment Systems Branch (BTP ETSB) 11-5, as it provides guidelines to analyze postulated radioactive releases as a result of postulated leakage or failure of a waste gas storage tank

The WGS controls, collects, processes, stores, and disposes of gaseous radioactive wastes generated during normal operation, including AOOs. The WGS involves the gaseous radwaste system, which deals with potentially hydrogen-bearing and radioactive gases generated during plant operation. Additionally, it involves the management of building ventilation, containment purge, and condenser air removal system exhausts. The AP1000 WGS is a once-through, ambient-temperature, activated carbon delay system. The system includes a gas cooler, a moisture separator, an activated carbon-filled guard bed, and two activated carbon-filled delay beds. The system also includes an oxygen analyzer subsystem and a gas sampling subsystem. The major inputs to the WGS are RCS gases stripped from the CVS letdown flow by the WLS vacuum degasifier during RCS dilution and boration, as well as during degassing prior to a reactor shutdown. Other inputs to the WGS are the gases from the RCDT vent and the gases stripped from the RCDT liquid by the WLS degasifier.

The flow through the WGS consists of hydrogen and nitrogen (as carrier gases), fission gases, and water vapor. Influents to the WGS pass through the following four stages:

(1) a gas cooler, which cools the influent waste gas to 7.2 °C (45 °F) by a chilled water system

(2) a moisture separator, which removes the moisture formed when the gas steam is cooled

(3) a guard bed, which protects the delay beds from abnormal moisture carryover, or chemical contaminants, by removing them from the waste stream

(4) two 100-percent capacity delay beds

The fission gases in the waste gas stream undergo dynamic adsorption by the activated carbon in the delay beds and, therefore, experience significant delay during their transit through the beds. DCD Tier 2, Section 11.3.5.2 states that the COL applicant will identify the types of adsorbent media to be used in the WGS. This is COL Action Item 11.3-2, as identified in DCD Tier 2, Table 1.8-2. Radioactive decay of the fission gases during the delay periods significantly reduces the radioactivity of the gas flow leaving the system. The effluent from the delay bed passes through a radiation monitor and is discharged to the environs via the system ventilation exhaust duct and the plant vent. In response to RAI 460.005(C), the applicant stated that sufficient holdup time is provided by the WGS because the system can be isolated at any time. The system is not normally in operation. It is operated, as necessary, during changes in RCS boron concentration and when reductions in the RCS noble gas inventory are made. Because the anticipated operation in the system provides 61 days holdup of xenon isotopes and over 2 days holdup of krypton isotopes, the staff does not expect that any alteration in the system operation will be necessary due to adverse meteorological conditions. Therefore, the WGS satisfies GDC 60, as it relates to sufficient holdup capacity for retention of radioactive gaseous effluents.

The design data for the WGS are provided in DCD Tier 2, Table 11.3-2. In addition, a list of gaseous radwaste system instrumentation and control items is provided in this table. The system contains provisions for continuously monitoring the moisture level at the inlet of the guard bed. Monitoring the performance of individual components in the system is done by collecting and analyzing grab samples. Connections between the two delay beds allow for the collection of samples at the inlet and outlet of the guard bed, and at the outlet of the second delay bed. The WGS has a radiation monitor that continuously monitors the discharge from the delay beds. The monitor will automatically send a signal to terminate the discharge when the radiation level in the discharge stream reaches a predetermined setpoint. The COL applicant will determine this setpoint. A COL applicant referencing the AP1000 certified design should identify its planned operational setpoint for the WGS radiation monitor in its plant-specific ODCM. DCD Tier 2, Section 11.5.7 states that the COL applicant will identify operational setpoints for the radiation monitors and will identify programs for monitoring and controlling the release of radioactive material to the environment, thus eliminating the potential for unmonitored and uncontrolled release (see COL Action Item 11.5-1).

In addition to the WGS exhaust, the other exhaust released to the environs via the radiation monitored plant vents include:

- the containment purge exhaust
- the auxiliary building exhaust
- the annex building release
- the radwaste building exhaust

The turbine steam sealing (gland seal) system exhaust and the condenser air removal system exhaust, which includes the gland seal exhaust during plant startup, are routed to a common header that discharges the exhausts to the environs via a radiation-monitored turbine building vent. The gland seal system and condenser air removal system exhausts are not filtered prior to their release to the environs, as they are not normally radioactive. However, upon detection of unacceptable levels of radiation in the exhausts, which may occur as a result of a SG tube leak, appropriate corrective actions will be manually performed. The turbine building exhaust is released to the environs via unmonitored turbine building vents, because it is not expected to have detectable radioactivity. In DCD Tier 2, Section 11.3.3.3, the applicant provided release-point characteristics for the plant vent and the turbine building vent, through which the combined discharge of the condenser air removal system and the gland seal system occurs.

Based on the above, suitable control of releases from the WGS is provided by the radiation monitoring system (RMS), as discussed in DCD Tier 2, Section 11.5, which automatically sends a signal to terminate releases from the WGS when a high-activity setpoint is exceeded in the system discharge line. Furthermore, the WGS provides sufficient holdup capacity. Therefore, the WGS design conforms with GDC 60 with regard to the control of radioactive releases to unrestricted areas.

In response to RAI 460.005(D), the applicant discussed compliance with GDC 61. The fuel storage and handling areas for the AP1000 include the fuel handling area of the auxiliary building, which encloses the spent fuel pool (SFP), and the containment building, which encloses the reactor cavity. Based on the calculated radiological releases resulting from a design-basis fuel-handling accident (FHA) in either area, there is no need to provide safety-related isolation or filtration systems to maintain plant safety (see DCD Tier 2, Section 15.7.4).

The ventilation systems serving these plant areas incorporate specific design features to mitigate the potential releases of abnormal (i.e., non-design-basis accident) airborne radioactivity from these areas. In addition to automatic isolation of the fuel handling area or containment purge valves due to a high-radiation signal, the isolation dampers or valves can be manually controlled from the main control room (MCR). The fuel handling area isolation dampers and containment isolation valves are provided with remote position indication. During abnormal airborne radiological conditions, the containment purge valves can be manually opened, through administrative procedures, to override a high-radiation signal, thereby allowing cleanup of the containment atmosphere. DCD Tier 2, Section 9.4.7.4 states that the exhaust air filtration units of the containment air filtration system (VFS) are designed and tested in accordance with American Society of Mechanical Engineers (ASME) Standards N-509-1989 and N-510-1989. These ASME standards discuss the instrumentation necessary for the periodic inspection and verification of system airflow rates, air temperatures, and filter pressure drops. Based on the above, the staff finds that the WGS complies with GDC 61, as it relates to radioactivity control in the WGS and the ventilation systems associated with fuel storage and handling areas.

In DCD Tier 2, Appendix 1A, the applicant provided a discussion of how the VFS meets the guidelines of RG 1.140, "Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants." As shown in DCD Tier 2, Table 9.4-1, the VFS has a 4-inch charcoal absorber and HEPA filters upstream and downstream of the absorber. The staff finds that the applicant has credited filter efficiencies of 90 and 99 percent for removal of iodine and other radionuclides in particulate form, respectively, in its calculation of gaseous effluents from containment purge exhaust. These efficiencies are in accordance with the specified efficiencies for 4-inch charcoal absorber and HEPA filters in RG 1.140. Therefore, the staff agrees with the filter efficiencies credited by the applicant in the calculation of containment purge exhaust effluents.

Although the auxiliary building and annex building exhausts are not normally filtered prior to their release, as stated above, the ventilation systems serving these areas incorporate design features that provide automatic filtration of the exhausts, prior to their release, under certain circumstances. Specifically, a high-radiation signal from any of the monitors in the exhaust ducts of the annex building, the fuel handling area of the auxiliary building, and the radiologically controlled portion of the auxiliary building will result in isolation of the normal supply and (unfiltered) exhaust ducts to the affected area and will connect the VFS exhaust filter and fans to the isolated area. (See DCD Tier 2, Sections 9.4.3.2.3.2 and 9.4.7.2.3.) On the basis of the above discussion and the evaluation presented in Section 9.4 of this report, the staff finds that the WGS meets the guidelines of RG 1.140 as they relate to the normal ventilation exhaust systems for air filtration.

The WGS is a non-safety-related system and has no accident mitigation functions. The WGS and the structures housing this system are designed in accordance with the applicable positions of RG 1.143 with respect to the following guidelines for gaseous radwaste systems:

- general guidelines for design, construction, and testing criteria for radwaste systems
- specific seismic design criteria for the WGS
- general seismic design criteria for structures housing radwaste systems
- general guidelines for providing quality assurance for radwaste management systems

DCD Tier 2, Appendix 1A, pertaining to the AP1000 radwaste management systems' conformance with RG 1.143, provides a discussion of how the design of the WGS and its housing structures meet the applicable guidelines of RG 1.143. DCD Tier 2, Appendix 1A, Criteria Section C.2.3, states that the guard bed and the delay beds, including supports, in the gaseous radwaste system are designed for seismic loads in accordance with RG 1.143. Seismic loads for this equipment were established using one-half of the safe-shutdown earthquake floor response spectra. The loads resulting from this seismic response spectra are equivalent to, or greater than, those resulting from an operating-basis earthquake. The WGS is housed in a seismic Category I structure (the auxiliary building). The QA program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall QA program described in DCD Tier 2, Chapter 17.

In DCD Tier 2, Table 3.2-3, the applicant classified WGS equipment and components such as the gas cooler, sample pumps, guard and delay beds, moisture separator, and applicable valves as AP1000 Class D (i.e., RG 1.26 Quality Group D). The QA program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall QA program described in DCD Tier 2, Chapter 17. DCD Tier 2, Section 17.5 states that the COL applicant will address its design phase QA program, as well as its QA program for procurement, fabrication, installation, construction and testing of structures, systems and components in the facility. The evaluation of the overall QA program is in Chapter 17 of this report. As set forth in Chapter 17 of this report, a COL applicant will address these matters pursuant to COL Action Item 17.5-1, and the staff will review them in the context of the COL application. The staff finds the WGS acceptable with respect to meeting QA guidance specified in RG 1.143, provided that the overall QA program described in any particular COL application is acceptable.

Because the potential exists for a buildup of explosive mixtures of hydrogen and oxygen in the WGS, the system should be designed to either withstand the effects of a hydrogen explosion, or have design features to preclude the formation or buildup of explosive mixtures, in accordance with SRP Section 11.3 guidelines. DCD Tier 2, Section 11.3.1.2.3.1, and the applicant's response to RAI 460.005(B) describe the design features for preventing the formation or buildup of explosive mixtures in the WGS. The WGS operates at a slightly positive pressure to prevent air in-leakage. A continuous purge flow of nitrogen is provided at the outlet of the WGS to prevent back-leakage of air through the discharge check valves. Dual oxygen analyzers are provided for continuous sampling in a side stream taken off the process flow paths. These analyzers sound an alarm, both locally and in the MCR, upon high oxygen levels. The alarm setpoint is at an oxygen concentration level that would allow adequate time for operator action. A hydrogen analyzer is also provided for direct measurement of hydrogen concentration in the sampling side stream. The operator can use the analyzer reading, in conjunction with a flammability chart, to assess the flammability potential during an upset situation in which oxygen enters the system. The entire system is electrically at the same potential, thereby eliminating the buildup of static electricity and sparking. The WGS throttling and isolation valves are packless metal diaphragm types which eliminate leakage into or out of the system through the steam seals. The dual oxygen analyzers are independent such that at an operator selectable oxygen concentration of 4 percent or less, the system automatically provides a signal to isolate oxygen inputs and initiate a nitrogen purge. Based on the above information, the staff finds that the WGS satisfies GDC 3 for protection from the potential effects of an explosive mixture.

The applicant calculated annual gaseous effluent releases using the PWR-GALE code (see DCD Tier 2, Table 11.3-3). DCD Tier 2, Table 11.2-6 provides the standard design parameters for running the computer program, which calculates expected primary and secondary coolant radionuclide concentrations and gaseous effluents. DCD Tier 2, Tables 11.3-1 and 11.3-2 list the design data for the WGS. DCD Tier 2, Figures 11.3-1 and 11.3-2 depict the schematics and the P&ID of the WGS. Demonstration of specific compliance with the requirements of 10 CFR Part 50, Appendix I, for a maximally exposed offsite individual and population doses resulting from gaseous effluents depends on site-specific factors and is, therefore, not within the scope of the AP1000 standard design. The staff will review such matters for each COL application. DCD Tier 2, Section 11.5.7 states that the calculation of offsite individual doses is the responsibility of the COL applicant. In addition, DCD Tier 2, Section 11.3.5.1 states that the COL applicant will provide a site-specific cost-benefit analysis to address the requirements of 10 CFR Part 50, Appendix I, regarding population doses resulting from gaseous effluents. This is COL Action Item 11.3-1, as identified in DCD Tier 2, Table 1.8-2. This COL action item addresses Criterion 8 which was discussed in Section 11.1 of this report. The staff finds this COL action to be acceptable to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix I.

DCD Tier 2, Table 11.3-4 provides the ratios of the airborne concentrations of radionuclides listed in 10 CFR Part 20, Appendix B, Table 2, Column 1, at the site boundary to the concentration limits for these radionuclides. The table shows that the sum of the ratios is 0.33, which is within the criterion of 1.00 set forth in Table 2, Note 4. In response to RAI 460.001, the applicant explained that the assumption used for the maximum release concentrations is based on 1 percent failed fuel with the exception of iodine and noble gases. These are limited by TS to 0.25 percent failed fuel. The staff finds this assumption acceptable because a 1 percent fuel failure rate is consistent with SRP 11.3, and the TS limit governs the fuel failure rate with respect to iodine and noble gases, thus providing a basis for deviating from the SRP guidance for these fission products. On the basis of the results presented in DCD Tier 2, Table 11.3-4, the staff finds that the WGS design complies with 10 CFR 20.1302, and Criterion 7 which was discussed in Section 11.1 of this report.

In its response to RAI 460.005(A), the applicant provided a waste gas system leak or failure analysis, as well as the justification for the assumptions used in that analysis. The analysis was performed to demonstrate that the WGS design meets the applicable guidelines of BTP ETSB 11-5. This BTP stipulates that the total body dose at the exclusion area boundary (EAB), as a result of the release of radioactivity for two hours from a postulated failure of the WGS, calculated in accordance with the BTP assumptions, should not exceed 0.5 rem. The applicant analyzed the accident using a short-term (0–2 hours) χ/Q of 6×10^{-4} seconds per meter-cubed (sec/m^3) at the EAB, a release duration of 1 hour, instead of 2 hours, as suggested by the BTP, and other assumptions consistent with those in the BTP. In the above response, the applicant justified a release duration of 1 hour as consistent with the isolation time of the AP1000 design. The applicant calculated a 0 - 2 hour total body dose within 0.5 rem, which satisfies BTP ETSB 11-5. Based on the above, the staff finds the analysis acceptable.

The staff reviewed all applicable information submitted in DCD Tier 2, Section 11.3 and in the applicant's responses to staff RAIs related to the radwaste management systems for the AP1000. Based on the above information, as discussed in the evaluation, the staff concludes that the WGS meets the requirements of 10 CFR 50.34a, as it relates to the provision of design information sufficient to demonstrate that the design objectives for the equipment necessary to control releases of radioactive effluents to the environment have been met.

11.3.2 Conclusions

Based on the above, the staff concludes that the design of the WGS is acceptable in that it meets the acceptance criteria provided in SRP Section 11.3 and described below:

- The system is capable of maintaining gaseous effluents in unrestricted areas below the limits stated in 10 CFR 20.1302 during periods of fission product leakage at design levels for the fuel.
- The system's design features control the release of radioactive materials to the environs via gaseous effluents in accordance with GDC 60.
- The system's design features comply with GDC 61, as it relates to radioactivity control in the WGS and the ventilation systems associated with fuel storage and handling areas.
- The system's design features comply with GDC 3, as it relates to protecting the WGS from the effects of an explosive mixture of hydrogen and oxygen.
- A COL action Item provides for demonstrating WGS compliance with 10 CFR Part 50, Appendix I, requirements for population doses (COL Action Item 11.3-1).
- The system's design features satisfy RG 1.140 and RG 1.143.
- The capability of the system's design features ensure WGS conformance with BTP ETSB 11-5 guidelines in the analysis of a postulated waste gas system leak or failure.
- The application provides information sufficient to comply with 10 CFR 50.34a, as it relates to demonstrating that the design objectives for the equipment necessary to control releases of radioactive effluents to the environment have been met.

11.4 Solid Waste Management System

11.4.1 System Description and Review Discussion

The staff reviewed DCD Tier 2, Section 11.4, "Solid Waste Management," in accordance with the guidance and acceptance criteria described in SRP Section 11.4. Paragraph II of SRP Section 11.4 provides the following acceptance criteria for the WSS:

- 10 CFR 20.1302, as it relates to radioactive materials released in gaseous and liquid effluents to unrestricted areas. These criteria apply to releases resulting from WSS operation during normal plant operations and anticipated operational occurrences.

- 10 CFR 50.34a, as it relates to providing adequate system design information

- GDC 60, as it relates to the design of the WSS incorporating the means to handle solid wastes produced during normal plant operation, including AOOs

- GDC 63 and 64, as they relate to the design of the radioactive management system to monitor radiation levels and leakage

- 10 CFR Part 61, as it relates to classifying, processing, and disposing of solid wastes

- 10 CFR Part 71, as it relates to packaging of radioactive materials

The relevant requirements listed above are reviewed using the regulatory positions identified in RG 1.143, as they relate to the seismic design and quality group classification of the components used in the WSS and the structures housing this system, as well as the provisions to control leakage.

The WSS consists of equipment and instrumentation to collect, segregate, store, process, sample, and monitor solid wastes. The WSS is designed to collect and accumulate wet solid wastes (e.g., spent ion exchange resins, deep bed filtration media, filter cartridges), dry active wastes (e.g., rugs, paper, clothing, HVAC filters), and mixed wastes for shipment to a licensed waste disposal facility. The system is located in the auxiliary and radwaste buildings. Processing and packaging of wastes are completed by mobile systems in the auxiliary and radwaste buildings. The packaged waste is stored in the auxiliary and radwaste buildings until it is shipped offsite to a licensed disposal facility.

DCD Tier 2, Figure 11.4-1 identifies the flows of wastes through the WSS. DCD Tier 2, Table 11.4-10 lists WSS equipment design parameters. DCD Tier 2, Table 3.2-3 identifies the AP1000 WSS pumps, tanks, filters, and certain valves as Class D. The spent resin system, which is part of the WSS, contains the following major components:

- two spent resin tanks, each with a volume of 8.5 cubic meters (m^3) (300 cubic feet (ft^3))
- a resin mixing pump
- a resin transfer pump
- a resin fines filter
- a resin sampling device

The spent resin tanks provide holdup capacity for spent resin and filter bed media decay before processing. The resin mixing pump fluidizes and mixes the resins in the spent resin tanks, transfers water between spent resin tanks, discharges excess water from the tanks to the WLS for processing and disposal, and flushes the resin transfer lines. The resin transfer pump recirculates spent resins, via either one of the spent resin tanks, for mixing and sampling, for transferring spent resins between tanks, and for blending high- and low-activity resins to meet the specific activity limit for disposal. The resin transfer pump is also used to transfer spent resins to a waste container in the fill stations or in its shipping cask, which is located in the auxiliary building railcar bay. The resin sampling device collects a representative sample of the spent resin either during spent resin recirculation or during spent resin waste container filling operations. The filter transfer cask permits remote changing of filter cartridges, dripless transport to the storage area, transfer of the filter cartridges into and out of the filter storage, and loading of the filter cartridges into disposal containers. The resin dewatering pump, which is a part of the potable dewatering system, removes water from the spent resin disposal container and discharges it to the spent resin tanks. Waste disposal containers are to be selected from available designs that meet the requirements of the U.S. Department of Transportation (DOT) and the NRC.

A filter transfer cask is used to change the high-activity filters of the CVS and spent fuel cooling system. The filter vessel is drained. If recent applicable sample analysis for the filter media is available, the filter cartridge can be loaded directly into a disposal container. However, if analysis is required, the filter cartridge is placed in a high-activity filter storage tube until sample analysis results are available. Upon completion of the analysis, and determination of packaging requirements, a transfer cask is used to retrieve the cartridge from the storage tube and deposit it in the waste container.

DCD Tier 2, Section 11.4 states that the WSS does not handle large, radioactive waste materials, such as core components. In RAI 460.009, the staff requested additional information on how these radioactive materials would be handled. In response, the applicant stated that large and highly radioactive core or primary components will be handled on a specialized basis. In general, these components can be held in the radwaste accumulation area or the SFP for decay, or decontaminated either in place or in the hot machine shop and shipped to offsite facilities. Bays in the radwaste building can also be used as temporary staging and processing areas to decontaminate and package such components.

At the radwaste building, low- and moderate-activity filter cartridges are deposited into disposal or storage drums. The drums are stored within portable shield casks in the shielded accumulation room, which is serviced by the mobile systems facility crane. Depending on dose rates and analysis results, stabilization may or may not be needed. Cartridges not needing stabilization are loaded into standard, 55-gallon shipping drums with absorbent. The drums may be compacted using a mobile system. When stabilization is necessary, the cartridges may be loaded into either high-integrity containers or standard drums. If standard drums are used, mobile equipment is employed to encapsulate the contents of the drums. DCD Tier 2, Section 11.4.2.3.2 provides the details of the spent filter processing operations.

Chemical wastes are accumulated in the chemical waste tank; they are normally processed by mobile equipment to reduce the volume and packaged into drums. The drums are then stored in the packaged waste storage room of the radwaste building. Mixed wastes are collected in suitable containers and brought to the radwaste building. They are normally sent to an offsite facility having mixed waste processing and disposal capabilities.

Normally, the spent resin from the condensate polishing system demineralizers is nonradioactive and is transferred directly to a truck or to the spent resin tank until it can be removed offsite. If the condensate resins are radioactive, they are transferred from the condensate polishing vessels or a spent resin tank to a temporary processing unit. The resins are then dewatered and processed, as necessary, for offsite disposal. The applicant estimates that the condensate polishing spent resins will have negligible radioactivity (see DCD Tier 2, Table 11.4-6). Also, the applicant estimates the maximum generation volume for radioactive condensate polishing resins to be 5.83 m^3 (206 ft^3) per year. In DCD Tier 2, Sections 10.4.6.3 and 11.4.2.1, the applicant stated that nonradioactive spent resins do not need any special packaging, and that radioactive condensate polishing resin will be disposed of in containers, as permitted by DOT regulations. After packaging, the resins may be stored in the radwaste building. DCD Tier 2, Section 10.4.6.3 states that a spill containment barrier is provided to contain spent resin tank or condensate polish vessel contents in the event of a tank failure. The spill containment barrier is a curb surrounding the area containing the spent resin tank and condensate polisher vessel, which has sufficient height to contain the contents of a full tank or vessel.

On the basis of their contact dose rates, dry wastes are segregated by portable shielding into low-activity, moderate-activity, and high-activity wastes. The bags or containers containing these dry wastes are transported to the radwaste building and placed into low-, moderate-, or high-activity storage areas, depending upon their activity levels. High-activity wastes are normally compacted in drums using a mobile compactor system. Moderate-activity wastes are sorted and compacted by mobile equipment. The packaged wastes may be loaded directly into a truck for shipment, or may be stored in the packaged waste storage room until a truck load is accumulated. Low-activity waste generally contains a large amount of nonradioactive material. These wastes will usually be processed through a mobile radiation monitoring and sorting system to remove nonradioactive items for reuse or local disposal. The remaining radioactive wastes are then compacted or packaged for disposal. DCD Tier 2, Section 11.4.2.3.3 and Figure 11.4-1 provide the processing details for dry solid wastes.

DCD Tier 2, Section 11.4.1.3 states that the waste disposal containers are to be selected from available designs that meet (1) the disposal requirements of 10 CFR Part 61, (2) specific criteria of the disposal facility chosen, and (3) the radioactive waste transportation requirements of 10 CFR Part 71 and relevant DOT regulations. The verification of waste characteristics, waste packaging, and waste disposal are within the purview of the COL applicant. Similarly, the staff considers that the COL applicant will control the development of a process control program (PCP), in compliance with 10 CFR Part 61, which identifies the operating procedures (i.e., boundary conditions for a set of process parameters such as settling time, drain time, drying time, etc.) for processing wet solid wastes. Therefore, for each COL application, the staff will review the PCP, including dewatering or solidification (if performed), and determine whether the COL application demonstrates that the WSS complies with the requirements of 10 CFR 61.55, 10 CFR 61.56, 10 CFR Part 71, and relevant DOT regulations. A COL applicant referencing the AP1000 certified design should submit a PCP that identifies the operating procedures for processing wet solid wastes. The mobile system PCP should include a discussion of conformance to RG 1.143, and should address the issues raised in Generic Letters (GLs) 80-009 and 81-039. It should also include a discussion of equipment containing wet solid wastes in the nonseismic radwaste building. In DCD Tier 2, Section 11.4.6, the applicant identified a COL action item to meet the above guidance concerning dewatering or solidification of we wastes. This is COL Action Item 11.4-1, as identified in DCD Tier 2, Table 1.8-2. It is consistent with the guidance in BTP ETSB 11-3.

The liquid and gaseous effluents resulting from the WSS operation are released during normal operation, including AOOs, to unrestricted areas through the WLS, and the monitored plant vent, respectively. The liquids resulting from wet waste processing are routed to the WLS to be processed before release to the environment. Specifically, the excess water from the spent resin tanks is pumped by the resin mixing pump to the WLS through a resin-fines filter. The radwaste and auxiliary buildings contain and drain spillage to the WLS through the radioactive waste drain system. Sloped floors and floor drains are provided to collect and control the release of radioactive materials that could be removed from stored solid waste by water contact.

The primary spent resin tanks are located in the seismic Category I auxiliary building that will retain the maximum liquid and spent resin inventory of the spent resin tanks. The spent resin tank vent and overflow connections have screens to prevent the discharge of spent resins. The WSS has a resin-fines filter to minimize the spread of high-activity resin fines. The liquids and gases that result from WSS operation are monitored by the WLS and WGS radiation monitors before their release to the environs. In Sections 11.2 and 11.3 of this report, the staff evaluated whether the activity of liquid and gaseous effluents is within the release limits of 10 CFR 20.1302 and found the AP1000 design to be acceptable.

In response to RAI 460.006, the applicant identified the system's design features for complying with GDCs 60, 63, and 64. GDC 60 requires that means be provided to handle radioactive solid wastes produced during normal reactor operation, including AOOs. GDC 63 and 64 address the radioactive system being designed for monitoring radiation levels and leakage within the system. DCD Tier 2, Section 11.4 states that the WSS has the capability to handle the applicable categories of solid radwaste. The higher radioactivity solid wastes, such as primary resins and filters, are handled and packaged in specific areas of the auxiliary building. As part of the auxiliary building, the HVAC for these areas is supplied by the radiologically controlled area ventilation system (VAS). The VAS is continuously monitored for radioactivity, and if activity above a predetermined setpoint is detected, the discharge is automatically diverted to the VFS. The VFS provides filtration and additional monitoring before discharge via the plant vent.

Liquid that drains from the auxiliary building is collected in the auxiliary building sump and routed to the WLS for processing and "monitored discharging." An area radiation monitor (ARM) is provided in this area. Lower activity solid wastes are processed and packaged in certain areas of the radwaste building. Ventilation for these areas is supplied by the radwaste building HVAC system, which includes a radiation monitor and alarm before discharge to the plant vent. The floor of the radwaste building is curbed and sloped to ensure all drainage is collected in sumps, which are in turn routed to the auxiliary building sump for processing by the WLS. An ARM is provided in this area. Based on the above discussion, the staff finds that the WSS complies with GDC 60, 63, and 64 with respect to monitoring and controlling solid waste storage and monitoring releases of radioactive materials to the environment, respectively.

The WSS is a non-safety-related system and has no accident mitigation functions. The bulk of the system is located in the radwaste building, which is not a seismic Category I structure. According to DCD Tier 2, Appendix 1A, which pertains to the conformance of the radwaste management systems to RG 1.143, the primary spent resin tanks are located in the auxiliary building, which is a seismic Category I structure. This seismic Category I structure will hold the maximum liquid and spent resin inventory of the spent resin tanks. Thus, the WSS complies with Positions C.3.3 and C.5 of RG 1.143 regarding seismic design criteria for structures housing solid radwaste management systems.

The design of components and subsystems of the mobile systems that are used by contractors to process wet solid wastes and chemical wastes are not within the scope of the AP1000 standard design. The portion of the WSS that is within the scope of the AP1000 standard design is designed in accordance with Positions C.3, C.4, and C.7 of RG 1.143 with respect to specific guidelines for solid radwaste systems; general guidelines for design, construction, and testing criteria for radwaste systems; and general guidelines for providing QA for radwaste management systems. DCD Tier 2, Appendix 1A provides a detailed discussion of how the design of the WSS, and its housing structure, meets the applicable guidelines of RG 1.143. Specifically, the subject Appendix states that the WSS components are designed and tested to the guidelines set forth in the codes and standards listed in Table 1 of RG 1.143.

DCD Tier 2, Table 3.2-3 states that components such as pumps, tanks, filters, and applicable valves of the WSS are designed to AP1000 Class D quality standards, which are equivalent to the Quality Group D standards of RG 1.26. The QA program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall QA program described in DCD Tier 2, Chapter 17. DCD Tier 2, Section 17.5 states that the COL applicant will address its design phase QA program, as well as its QA program for procurement, fabrication, installation, construction and testing of structures, systems and components in the facility. The evaluation of the overall QA program is in Chapter 17 of this report. As set forth in Chapter 17 of this report, a COL applicant will address these matters pursuant to COL Action Item 17.5-1, and the staff will review them in the context of the COL application. The staff finds the WSS acceptable with respect to meeting QA guidance specified in RG 1.143, provided that the overall QA program described in any particular COL application is acceptable.

The staff will review, on a plant-specific basis, the mobile systems facility proposed by the COL applicant (or its contractors) against the guidelines of RG 1.143. A COL applicant referencing the AP1000 certified design should discuss how any mobile processing equipment intended for use in the processing of solid radwaste meets the guidelines of RG 1.143 (see COL Action Item 11.4-1).

Based on the above, the staff finds that the AP1000 design conforms to the relevant guidance of the regulatory positions identified in RG 1.143, as they relate to the seismic design, quality group classification of components used in the WSS and the structures housing the system, and the mobile process equipment.

BTP ETSB 11-3, Position B111, provides the staff's evaluation guidance regarding the characteristics of solid waste storage capacity necessary to allow time for short-lived radionuclides to decay prior to shipping. These characteristics are summarized as follows:

- Tanks accumulating spent resins from reactor water purification systems should be capable of accommodating at least 60-days waste generation at normal generation rates. Tanks accumulating spent resins from other sources, as well as tanks accumulating filter sludges should be capable of accommodating at least 30-days waste generation at normal generation rates.

- Storage areas for solidified wastes should be capable of accommodating at least 30-days waste generation at normal generation rates. These storage areas should be located indoors.

- Storage areas for dry wastes and packaged containment equipment should be capable of accommodating at least one full offsite waste shipment.

In its response to RAI 460.007, Revision 1, the applicant provided the following information:

- The expected spent resin generation rate is 11.33 m^3 (400 ft^3) per year. The AP1000 has two spent resin storage tanks, each with a capacity of 8.5 m^3 (300 ft^3). This storage capacity is capable of accommodating more than 60-days of waste generation.

- AP1000 does not incorporate waste solidification, but packaging of resin into high-integrity containers (HICs) may be considered analogous. A standard HIC provides more than 120-days of storage capacity. Space is available in Room 12374 of the auxiliary building for the storage of the HICs.

- Storage areas for dry wastes and packaged containment equipment in Rooms 50351 and 50352 of the radwaste building have sufficient capacity for more than two offsite shipments.

Based on the above, the staff finds that the AP1000 design has sufficient onsite storage capacity for the anticipated solid waste, consistent with BTP ETSB 11-3, Position B.III.

In GL 81-38, "Storage of Low-Level Radioactive Wastes at Power Reactor Sites," the staff provided guidance to licensees on the addition of onsite storage facilities for low-level radioactive wastes generated onsite. The staff recognizes that the need for additional onsite storage capacity for low-level radioactive wastes, beyond what has been provided in the AP1000 standard design, is a site-specific issue. This need will depend upon the availability of offsite low-level waste storage space for the site's wastes. Therefore, when such a need is identified, the COL applicant should submit the details of any proposed onsite, low-level radioactive waste storage facility to the NRC. The staff will review and evaluate such a proposed additional site-specific facility against the guidelines in GL 81-38, which is similar to the guidance in Appendix 11.4-A to SRP Section 11.4. However, the staff did not find it necessary to create a COL action item regarding the issues raised in GL 81-38 and, instead, asked the applicant, in RAI 460.008, to address them. In response, the applicant revised DCD Tier 2, Section 11.4.6, to identify GL 81-38 as a part of COL Action Item 11.4-1. The staff finds the revision to DCD Tier 2, Section 11.4.6 to be acceptable.

Based on the information in the DCD and RAI responses discussed above, the staff finds that the WSS meets the requirements of 10 CFR 50.34a, as they relate to the adequacy of design information.

11.4.2 Conclusions

Based on the above, the staff concludes that the design of the WSS is acceptable because it meets the acceptance criteria provided in SRP Section 11.4 as described below:

- The system, in conjunction with the WLS and WGS, is capable of maintaining the concentration of any liquid or gaseous effluents in unrestricted areas arising from system operation below the limits of 10 CFR 20.1302.
- Design features have been incorporated into the system to comply with GDC 60, 63, and 64.
- Provisions for onsite storage of processed solid wastes conform to BTP ETSB 11-3, Position B.III.
- Quality group and seismic classification applied to the structures housing the system conform to RG 1.143.
- COL applicants will be responsible for complying with the requirements of 10 CFR Part 61 and 10 CFR Part 71 (part of COL Action Item 11.4-1).
- The applicant provided information sufficient to satisfy the requirements of 10 CFR 50.34a regarding the adequacy of design information.

Based on the above evaluation of the WSS, conducted in accordance with the applicable acceptance criteria of Section 11.4 of the SRP, the staff finds the WSS to be acceptable.

11.5 Process and Effluent Radiological Monitoring and Sampling System

11.5.1 System Description and Review Discussion

The staff reviewed DCD Tier 2, Section 11.5, "Radiation Monitoring," in accordance with the guidance and acceptance criteria provided in SRP Section 11.5. Paragraph II of SRP Section 11.4 provides the following acceptance criteria for the process and effluent radiological monitoring and sampling system:

- 10 CFR 20.1302, as it relates to surveying radioactive effluents released to unrestricted areas

- 10 CFR Part 50, Appendix A, GDC 60, as it relates to controlling the release of radioactive materials to the environment

- GDC 63 and 64, as they relate to monitoring radiation in fuel storage and radioactive waste systems and associate handling areas (GDC 63) and the containment and the plant environs (GDC 64)

- 10 CFR 50.34(f)(2)(xvii) and 10 CFR 50.34(f)(2)(xxvii), as they relate to monitoring radiation and radioactivity levels for routine operating and accident conditions

Specific acceptance criteria for the relevant requirements identified above are as follows:

- The gaseous and liquid process streams, or effluent release points, should be monitored and sampled according to Tables 1 and 2 of SRP Section 11.5.

- The design of systems should meet the provisions of the applicable positions in RG 1.21, RG 1.97, and RG 4.15.

The process and effluent radiological monitoring and sampling system is used to measure, record, and control releases of radioactive materials in plant process streams and effluent streams. The system consists of permanently-installed sampling and monitoring equipment designed to indicate routine operational radiation releases, equipment or component failure, system malfunction or misoperation, and potential radiological hazards to plant personnel or to the general public. The system generates signals to initiate the operation of certain safety-related equipment to control radioactive releases under specified condition, as described below.

In the AP1000 design, radiation monitors are provided for the following processes and effluents:

- the auxiliary building fuel handling area exhaust

- exhaust from the rest of the auxiliary building areas, excluding two electrical penetration rooms and two reactor trip switchgear rooms

- containment air filtration exhaust

- exhaust from the health physics area (in annex building) and the hot machine shop area (annex building)

- exhaust from the rest of the annex building

- radwaste building exhaust

- gaseous radwaste system exhaust

- plant vent exhaust
- containment atmosphere
- turbine island vent discharge
- MCR supply air
- primary sampling gaseous sample
- primary sampling liquid sample
- main steamline
- SG blowdown
- component cooling water system
- service water blowdown
- liquid radwaste discharge
- waste water discharge

DCD Tier 2, Sections 11.5.2.3.1, 11.5.2.3.2, and 11.5.2.3.3, and Table 11.5-1 provide information on the monitored stream, detector type, normal range for the detector, automatic function associated with the monitor, principal monitored radionuclides, and the locations of all liquid and gaseous process systems and effluent radiation monitors. DCD Tier 2, Table 11.5-1 indicates that the radiation monitors at the MCR supply air duct are safety-related and the monitors for the containment atmosphere are seismic Category I.

The exhausts from the diesel generator rooms (located in the stand-alone diesel generator building), personnel areas, the electrical and mechanical equipment rooms of the annex building, and the electrical penetration and reactor trip switchgear rooms of the auxiliary building are not monitored because these areas do not contain any radioactive materials, and they interface only with clean areas, thus precluding transfer of radioactive materials from adjoining areas.

The annex building general area HVAC system normally maintains the personnel areas of the annex building at a slightly positive pressure with respect to adjoining areas. Therefore, the staff finds that the justification for not monitoring the exhausts of those areas mentioned above is acceptable. Additionally, the staff finds that the above mentioned DCD Tier 2 sections and table include all of the applicable gaseous and liquid processes and effluent streams identified in Tables 1 and 2 of SRP Section 11.5.

DCD Tier 2, Tables 11.5-1 and 11.5-2 identify all safety-related monitors, and DCD Tier 2, Section 7.1.4 provides information on the requirements for safety-related monitors. DCD Tier 2, Tables 11.5-1 and 11.5-2 list other radiation monitors which are discussed in DCD Tier 2, Section 11.5.

Based on the above, the staff finds that the effluent monitors comply with GDC 64 with regard to the monitoring of radioactive liquid and gaseous effluents from the plant.

The ARMs monitor the radiation levels in selected areas throughout the plant. These are provided to supplement the personnel and area radiation survey provisions of the AP1000 health physics program. DCD Tier 2, Table 11.5-2 lists the following areas with ARMs, along with the nominal range and type of radiation measured:

- containment high range
- primary sample room
- containment area personnel hatch
- MCR
- chemistry laboratory area
- fuel handling area
- railcar bay area
- liquid and gaseous radwaste area
- technical support center
- radwaste building mobile systems facility
- hot machine shop
- annex staging and storage area

The detectors in these areas are gamma-sensitive Geiger-Muller tubes. These detectors are capable of detecting the types and energies of radiation emitted from fuel and radioactive waste. A local readout and alarm module is located in each area to visually guide personnel before they enter the monitored areas. The containment ARMs and fuel handling ARMs provide an alarm locally and in the MCR. Based on the above information, the staff finds that the process and effluent monitoring and sampling system for the AP1000 standard design provides the needed monitoring for fuel and radioactive waste storage, and thus, complies with GDC 63.

Besides the plant vent accident range monitor and the condenser air removal exhaust monitor, which monitor radioactive gaseous effluents during accidents, the following special-purpose radiation monitors are provided either for monitoring during an accident or triggering an automatic control action:

- Two main steamline radiation monitors, for monitoring radionuclide concentrations in the two main steamlines and using the concentration data for calculating radioactive releases to the environment if the SG safety relief or power-operated relief valves are used to release steam to the atmosphere.

- Four containment high-range radiation monitors, for monitoring gamma radiation intensities inside the containment following an accident and using the data for estimating radioactive material inventory in the containment volume.
- Radiation-level monitors (two particulate detectors, two iodine detectors, and two noble gas detectors), to monitor the radiation level in the air supply to the MCR and to activate the MCR emergency habitability system if the concentrations of radioactive materials exceed predetermined setpoints for the monitors.

DCD Tier 2, Sections 11.5.2.3.1 and 11.5.6.2 state that the MCR radiation monitors and containment high-range monitors are environmentally and seismically qualified in accordance with the guidelines of RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," and RG 1.100, "Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants." These monitors receive Class 1E power. DCD Tier 2, Table 11.5-1 indicates that the steamline radiation monitors are non-safety-related and receive non-Class 1E power. DCD Tier 2, Section 11.5.2.3.1 and Table 11.5-1 provide the nominal range and type of radiation measured, the detector type, the location, and the automatic control features (if provided) for these special purpose radiation monitors.

The staff finds the range provided in DCD Tier 2, Table 11.5-1 for gamma radiation measurement by the high-range containment radiation monitors inside the containment to be acceptable because it meets the range criterion for such monitors specified in NUREG-0737, Three Mile Island (TMI) Item II.F.1, Attachment 3, "Containment High-Range Radiation Monitoring." Therefore, the range complies with the applicable portions of 10 CFR 50.34(f)(2)(xvii). Also, the staff finds the ranges specified in DCD Tier 2, Table 11.5-1, for the steamline and MCR radiation monitors to be acceptable because they are consistent with applicable NRC guidance and industry standards. On the basis of the above discussion, the staff finds that these special-purpose monitors comply with GDC 60 and 64 in terms of their ability to control and monitor the release of radioactive materials to the environment.

The RMS initiates such control actions as reducing or terminating radioactive releases to the environment upon detection of high radiation levels by the monitors in accordance with GDC 60. Specifically, the WGS exhaust monitor and the liquid waste discharge monitor initiate control actions to terminate the applicable discharge upon detection of high radiation levels by the respective monitor. The MCR supply air duct radiation monitor isolates the MCR air intake and exhaust ducts and activates the MCR emergency habitability system upon detection of high radiation levels in the air intake by the MCR radiation monitor. The MCR habitability system is discussed in Section 6.4 of this report. The fuel handling area exhaust radiation monitor, the annex building exhaust radiation monitor, and the auxiliary building exhaust radiation monitor (each located upstream of its respective exhaust air isolation dampers) initiate control actions to automatically divert the exhaust from the applicable area to the VFS upon detection of high radiation levels in the exhaust of the applicable area by its associated radiation monitor. This is accomplished by closure of the affected area supply and exhaust air isolation dampers, opening of the applicable exhaust air isolation dampers of the VFS, and starting the containment air filtration exhaust unit. The turbine island vent discharge radiation monitor facilitates performance of corrective manual actions in a timely manner upon detection of high radiation levels in the subject exhaust. The SG blowdown radiation monitor and the waste water discharge monitor facilitate manual diversion of the applicable stream to the WLS for processing by that system upon the detection of high radiation levels in the applicable stream by the associated radiation monitor. The component cooling water system radiation monitor facilitates manual isolation of the system and timely performance of leak repairs upon detection of radiological leakage into the system. On the basis of the above discussion, the staff finds that the AP1000 design permits control of radioactivity releases to the environs, in accordance with GDC 60.

To comply with the numerical objectives in 10 CFR Part 50, Appendix I, for offsite doses resulting from gaseous and liquid effluents during normal plant operation, including AOOs, COL holders will need to limit annual and quarterly offsite doses. Additionally, if an applicant proposes to use treatment systems (e.g., waste gas treatment by delay beds, demineralizers to treat liquid radwaste, and VFS), the requirements for this design objective will be deemed to have been met if the annual dose is not greater than 5 millirems and the applicant submits an evaluation of the effect of the long-term buildup in the environment of radionuclides with half lives longer than 1 year. The COL applicant will implement the items described above, as specified in a plant controlled document. DCD Tier 2, Section 11.5.7 states that the COL applicant is responsible for addressing the 10 CFR Part 50, Appendix I guidelines for offsite individual doses and population doses via liquid and gaseous effluents. This is COL Action Item 11.5-3, as identified in DCD Tier 2, Table 1.8-2.

Additionally, a COL applicant will be required to limit average annual discharge concentrations from the WGS and WLS to comply with 10 CFR Part 20.1302 which defines the criteria for radionuclide concentration limits in liquid and gaseous effluents. A COL applicant will provide the associated setpoints for the applicable radiation monitors in the plant-specific ODCM. Properly designated setpoints, in conjunction with the automatic control features of the applicable effluent monitors (e.g., termination of the discharge or diversions through the VFS), will ensure that the AP1000 effluent monitors comply with 10 CFR 20.1302. The staff will review the plant-specific radiological effluent TSs, as well as the setpoints listed in the plant-specific ODCM, for each COL application. (Conformance with 10 CFR Part 50, Appendix I, and 10 CFR 20.1302 have been previously identified as COL Action Items 11.2-2, 11.2-4, and 11.3-1.) The COL applicant will develop an ODCM that contains the methodology and parameters used for calculation of offsite doses resulting from gaseous and liquid effluents. The ODCM will include planned discharge flow rates. The COL applicant will address operational setpoints for the radiation monitors, as well as programs for monitoring and controlling the release of radioactive material to the environment, thus eliminating the potential for unmonitored and uncontrolled release (COL Action Item 11.5-1).

The staff reviewed DCD Tier 2, Section 11.5, against the SRP guidelines in Section 11.5, Tables 1 and 2. These tables list provisions for monitoring and sampling gaseous and liquid effluent streams. DCD Tier 2, Sections 11.5.2.3.1 through 11.5.2.3.3, Tables 11.5-1 and 11.5-2, Tables 9.3.3-1 through 9.3.3-3, and Tables 9.3.4-1 and 9.3.4-2 set forth the provisions of the design for monitoring and sampling these effluent streams. The system provides for continuous and representative sampling of airborne particulate and iodine radioactivities for the plant vent discharge which is a major gaseous effluent stream. The system also provides for grab sampling for noble gases, iodines, particulates, and tritium for the gaseous radwaste system discharge. For liquid streams, the system provides grab sampling and analysis capability for gross radioactivity determination, identification of principal radionuclides and alpha emitters, and measurement of their concentration for the following areas:

- the chemical waste tank
- the primary spent resin tank
- the WLS monitor tanks
- the waste holdup tanks

SRP Section 11.5, Paragraph II.3, states that provisions should be made for administrative and procedural control for (1) necessary auxiliary or ancillary equipment, (2) special features for the instrumented radiological monitoring sampling, and (3) analysis of process and effluent streams. In RAI 460.011, the staff requested the applicant to demonstrate that the AP1000 design meets this guidance. In response to the RAI, the applicant stated that SRP Section 11.5, Paragraph II.3 cites RGs 1.21 and 4.15 for meeting this guidance. The AP1000 conforms to this guidance, as demonstrated in DCD Tier 2, Sections 9.3.3 and 11.5, particularly Tables 9.3.3-1 and 9.3.3-2 (which list plant sample points) and Tables 11.5-1 and 11.5-2 (which list radiation monitoring points). All major and potentially significant paths for release of radioactivity are monitored. RG 4.15 provides QA guidance for radiation monitoring programs. The guidelines provided in ANSI N13.1-1969 and RGs 1.21 and 4.15 (dealing with sampling programs, reporting radioactivity measurements, and QA for radiological monitoring programs) apply to operational programs. As such they are not within the scope of the AP1000 standard design. Consequently, the staff will review conformance of the radiological monitoring and sampling programs with the specific guidelines of the above documents on a plant-specific basis for each COL application.

DCD Tier 2, Section 11.5 states that the RMS is designed in accordance with ANSI N13.1-1969. DCD Tier 2, Section 11.5.7 states that the COL applicant is responsible for ensuring that the process and effluent monitoring and sampling program at its site conforms to the guidelines of ANSI-N13.1-1969, RG 1.21, RG 4.15. This is COL Action Item 11.5-2, as identified in DCD Tier 2, Table 1.8-2.

The ranges of the following AP1000 post-accident radiation monitors are consistent with the ranges specified in RG 1.97 for such monitors:

- the main steamline radiation monitors
- high-range radiation monitors
- plant vent accident range radiation monitor
- turbine island vent discharge radiation monitor
- primary sample room monitor

DCD Tier 2, Table 11.5-1 and Section 11.5.2.3.3 provide a discussion of postaccident monitoring and sampling instrumentation, particularly as it relates to the compliance of such instrumentation for plant gaseous effluents with the requirements of 10 CFR 50.35(f)(2)

(NUREG-0737, TMI Item II.F.1, Attachments 1 and 2). Based on a review of the above DCD Tier 2 sections, the staff finds that only the plant vent discharges gaseous effluents directly to the environment. The plant vent has an accident-range effluent monitor to continuously monitor noble gas concentrations in gaseous effluents during and following an accident. Also, the vent is designed to allow for grab samples and analysis of plant gaseous effluents for iodine and particulates during and following an accident. The staff confirmed, from DCD Tier 2, Section 11.5.2.3.3, that the AP1000 design provides a continuous sampling capability and onsite analysis capability for iodines and particulates in the plant vent gaseous effluent during and following an accident.

The turbine island vent discharge has a noble gas effluent monitor which can continuously monitor noble gas concentrations in gaseous effluents through the vent during normal operation, as well as during and following an accident. The upper limits for concentration measurements for the accident-range effluent monitor for the plant vent, the accident- and low-range effluent monitors for the condenser air removal system exhaust vent, and the high-range monitor for the containment area are bounded by the limits specified for such monitors in NUREG-0737, TMI Item II.F.1, Attachments 1 and 2. Accordingly, the staff finds the specified ranges for these monitors acceptable.

Furthermore, the staff reviewed the following information regarding accident monitoring instrumentation:

- procedures and/or methods for converting radiation measurements into release rates of gaseous discharges through the vents
- sampling techniques used to monitor and sample effluent gases to assure that a representative sample is taken
- the sampling system's capability to maintain isokinetic conditions during and following an accident
- collection techniques to extract a representative sample of radioactive iodine and particulates during and following an accident
- calibration frequency and techniques for radiation monitors
- shielding for the sampling systems and the shielding design of the systems to conform with the guidelines of NUREG-0737, TMI Item II.F.1, Attachment 2
- radiation reading capability (readings are continuous)
- location of instrument readouts

Based on its review, the staff finds that the accident monitoring instrumentation provided in the AP1000 design for monitoring noble gases in gaseous effluents, as well as for sampling and analyzing the plant effluent for post-accident releases of radioiodine and particulates, meets the guidelines of NUREG-0737, TMI Item II.F.1, Attachments 1 and 2, regarding accident monitoring instrumentation. Therefore, the design complies with the applicable portions of 10 CFR 50.34(f)(2)(xxvii), which incorporate the subject TMI requirements.

The staff reviewed the AP1000 design regarding the issues identified in NRC Bulletin 80-10, "Contamination of Nonradioactive System and Resulting Potential for Unmonitored, Uncontrolled Release to the Environment." Specifically, the staff reviewed the following AP1000 design features, as identified in DCD Tier 2, Sections 9.2.9, 9.3.5, 9.4.2, and 9.4.10:

- the ability to detect the contamination of nonradioactive systems
- the ability to prevent the potential for unmonitored and uncontrolled release of radioactive material to the environment

On the basis of this review, as discussed in this section and Section 11.2 of this report, the staff finds that the AP1000 design segregates the radioactive systems from the nonradioactive systems, and all radioactive or potentially radioactive effluent pathways are monitored before the effluents are released to the environment. For example, drain systems that carry radioactive wastes generally do not contain piping connections that could allow the inadvertent transfer of radioactive fluid into nonradioactive piping systems. Where such connections do exist, back-flow prevention is provided in the nonradioactive piping. The annex/auxiliary building nonradioactive HVAC system and the diesel generator building HVAC system are segregated from radioactive HVAC systems. The normally nonradioactive secondary coolant system sampling drains and other waste water are diverted to the WLS for processing and monitoring, if detected to be radioactive (a radiation monitor is provided for monitoring the normally nonradioactive waste water discharge). The staff further notes that the applicant considered the issues identified in NRC Bulletin 80-10 regarding contamination of nonradioactive systems as part of the COL surveillance issue (the applicant's submittal dated July 2004, WCAP-15800, Revision 3). On this basis, the staff finds that DCD Tier 2, Sections 9.2.9, 9.3.5, 9.4.2, and 9.4.10 satisfactorily address the concerns raised in NRC Bulletin 80-10. The design features in the AP1000 design are adequate to detect the contamination of nonradioactive systems and to prevent the potential for unmonitored and uncontrolled release of radioactive material to the environment. In addition, the staff expects that the COL applicant will periodically verify that these design features function as intended. A COL applicant referencing the AP1000 certified design should provide details of its proposed program to eliminate the potential for unmonitored and uncontrolled release of radioactive material to the environment. In DCD Tier 2, Section 11.5.7, the applicant stated that the above-requested program will be included in the site-specific ODCM (COL Action Item 11.5-1).

SRP Section 11.5, Paragraph II.2 states that provisions should be made to purge and drain sample streams back to the system of origin or to an appropriate waste treatment system. In RAI 460.010, the staff requested the applicant to explain the provisions in the AP1000 design to address this criterion. In response to the RAI, the applicant stated that AP1000 sample points are listed in DCD Tier 2, Tables 9.3.3-1 and 9.3.3-2 as either "Continuous" or "Grab" sampling.

Continuous sampling provides online monitoring where the sample is not physically removed from its system of origin. Therefore, these continuous sampling streams meet the guidance of the SRP. Grab sampling is discussed in DCD Tier 2, Sections 9.3.3.2.1 (liquid) and 9.3.3.2.2 (gas). As noted in those sections, purge capability is incorporated with the purge flow routed to the effluent holdup tank in the WLS. The samples themselves are carried to an onsite radioactive chemistry laboratory for analysis. This laboratory has provisions for draining radioactive, reactor coolant-grade samples to the WLS effluent holdup tank . Other radioactive samples are drained from the laboratory to the WLS chemical waste tank. A special provision is made in the primary sampling system for containment atmospheric samples, which are purged and pumped to the containment sump. As a contingency, this return connection could also be used for other samples from inside containment. Based on the above, the staff finds that the AP1000 design meets the guidance of SRP Section 11.5, Paragraph II.2, regarding disposition of sample streams.

11.5.2 Conclusions

The staff verified that sufficient information was provided in DCD Tier 2, Section 11.5, and the RAI responses discussed above. For the reasons set forth above, the staff concludes that the process and effluent radiological monitoring instrumentation and sampling systems are acceptable and meet the relevant requirements of 10 CFR 20.1302, 10 CFR 50.34(f)(2)(xvii) and 50.34(f)(2)(xxvii), as well as GDC 60, 63, and 64. This conclusion is based on the following:

- The staff reviewed the provisions proposed in DCD Tier 2, to sample and monitor all plant effluents in accordance with GDC 64. The process and effluent radiological monitoring and sampling systems include instrumentation for monitoring and sampling radioactivity in contaminated liquid, gaseous, and solid waste process and effluent streams. This is demonstrated by the fact that all the processes and effluent streams identified in Section 11.5, Tables 1 and 2, of the SRP are included in DCD Tier 2, Section 11.5.2.3 and DCD Tier 2, Table 11.5-1.

- The staff reviewed the provisions for conducting sampling and analytical programs, in accordance with the guidelines in RG 1.21 and 4.15, as well as the provisions for sampling and monitoring process and effluent streams during postulated accidents in accordance with the guidelines in RG 1.97. These sampling and analytical programs conform to the guidance.

- The staff reviewed the provisions proposed in DCD Tier 2, to provide automatic termination of effluent releases and to ensure control over discharge, in accordance with GDC 60. Section 11.5.1 of this report discusses controlling releases of radioactive materials from WGS exhaust, WLS discharge, MCR air supply, fuel handling area, annex building exhaust, auxiliary building exhaust, turbine island vent discharge, SG blowdown, waste water discharge, and component cooling water. In Section 11.5.1 of this report, the staff reviewed and found the design features aimed at controlling radiation releases acceptable.

As discussed in Section 11.5.1 of this report, the staff review included the provisions proposed in DCD Tier 2, for sampling and monitoring the fuel handling and waste storage areas in accordance with GDC 63.

Based on the above review, the staff has determined that the AP1000 RMS design meets the guidelines of SRP Section 11.5. Therefore, it is acceptable.

12. RADIATION PROTECTION

12.1 Introduction

The AP1000 Design Control Document (DCD) Tier 2, Chapter 12, "Radiation Protection," describes the radiation protection measures of the AP1000 reactor design and operating policies. The U.S. Nuclear Regulatory Commission (the NRC or staff) evaluated this information against the criteria in Chapter 12, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants—LWR Edition" (SRP).

The AP1000 reactor design incorporates radiation protection measures intended to ensure that internal and external radiation exposures to station personnel, contractors, and the general population, resulting from plant conditions, including anticipated operational occurrences (AOOs), will be within regulatory criteria and will be as low as is reasonably achievable (ALARA). Doses to the public under these conditions are discussed in Chapter 11, "Radioactive Waste Management," of this report. As set forth in Chapter 11 of this report, normal operational doses to members of the public meet the requirements of 10 CFR Part 20 that set limits on doses for persons in unrestricted areas. With respect to occupational doses, the applicant's radiation protection design and program features should also be consistent with the guidelines of Regulatory Guide (RG) 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable," Revision 3, dated June 1978, or an acceptable alternative.

Compliance with these criteria provides assurance that doses to workers will be maintained within the limits of Title 10 of the Code of Federal Regulations (CFR) Part 20, "Standards for Protection Against Radiation." The requirements of 10 CFR Part 20 applicable to workers at an NRC-licensed facility limit the sum of the external whole-body dose (deep dose equivalent) and the committed effective equivalent doses resulting from radioactive material deposited inside the body (deposited through injection, absorption, ingestion, or inhalation) to 50 millisievert (mSv) (5 rem) per year with a provision (i.e., by planned special exposure) to extend it to 100 mSv (10 rem) per year with a lifetime dose limit of 250 mSv (25 rem) due to planned special exposures.

The SRP acceptance criteria provide assurance that the radiation doses resulting from exposure to radioactive sources both outside and inside the body can each be maintained ALARA and well within the limits of 10 CFR Part 20. The balancing of internal and external exposure necessary to ensure that their sum is ALARA is an operational concern. An applicant seeking a combined license (COL) must address these operational concerns, as well as programmatic radiation protection concerns.

The staff has received sufficient information from the applicant to conclude that the radiation protection measures incorporated in the AP1000 reactor design offer reasonable assurance that occupational doses during all plant operations will be maintained ALARA and within the limits of 10 CFR Part 20. The following sections present the bases for the staff's conclusions.

12.2 Ensuring That Occupational Radiation Doses Are As Low As Is Reasonably Achievable

The staff reviewed the information in DCD Tier 2, Section 12.1, "Assuring That Occupational Radiation Exposures Are As Low As Reasonably Achievable," to assess adherence to the guidelines in RG 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 3, as well as the criteria in Section 12.1 of the SRP regarding the radiation protection aspects of the AP1000 reactor design. Specifically, the staff reviewed DCD Tier 2, Section 12.1 to ensure that the applicant had either committed to adhere to the criteria of the RGs and staff positions referenced in Section 12.1 of the SRP, or had provided acceptable alternatives. The staff finds that DCD Tier 2, Section 12.1 is consistent with the guidance contained in these RGs and applicable staff positions. Therefore, the staff concludes that the relevant requirements of 10 CFR Part 20 have been met.

12.2.1 Policy Considerations

In DCD Tier 2, Section 12.1.1, "Policy Considerations," the applicant described the design, construction, and operational policies that have been implemented to ensure that ALARA considerations are factored into each stage of the AP1000 design process. The applicant has committed to ensure that the AP1000 plant will be designed and constructed in a manner consistent with the guidelines of RG 8.8. In particular, DCD Tier 2, Section 12.1.1.1, "Design and Construction Policies," states that the applicant has met this commitment by reviewing the plant design during the design phase for ALARA considerations. This ALARA policy is consistent with the guidelines of RG 8.8 and is therefore acceptable.

The requirements of 10 CFR Part 20 specify that all licensees must develop, document, and implement a radiation protection program. Specifically, this program shall encompass the ALARA concept and include provisions for maintaining radiation doses and intakes of radioactive materials ALARA. The detailed policy considerations regarding overall plant operations and implementation of such a radiation protection program are outside the scope of this design certification review. The operational ALARA policy forms the basis for the operating station's ALARA manual. In order to maintain doses to plant personnel ALARA, the applicant stated, in DCD Tier 2, Section 12.1.3, "Combined Licensee Information," that the COL applicant will review all plant procedures and modification plans that involve personnel radiation exposure to ensure that the ALARA policy is applied. In addition, a COL applicant referencing the AP1000 certified design will address operational ALARA concerns and will submit an operational ALARA policy which conforms to the requirements of 10 CFR Part 20 and the recommendations of Revision 2 to RG 1.8, "Qualification and Training of Personnel for Nuclear Power Plants," RG 8.8, and Revision 1-R to RG 8.10, "Operating Philosophy for Maintaining Occupational Radiation Exposure As Low As Is Reasonably Achievable." The staff identified this issue as COL Action Item 12.2.1-1.

12.2.2 Design Considerations

The plant radiation protection design should ensure that individual doses and total person roentgen equivalent man (rem) doses to plant workers and to members of the public are ALARA, and individual doses are maintained within the limits of 10 CFR Part 20. DCD Tier 2, Section 12.1.2, "Design Considerations," describes the objectives for the general design and shielding to minimize the time employees spend in radiation areas and to minimize radiation levels in areas routinely occupied and housing equipment requiring attention by plant personnel. DCD Tier 2, Section 12.1.2 also states that these design considerations are consistent with the guidelines in RGs 8.8 and 8.10. Specifically, DCD Tier 2, Section 12.1.2 states that the basic management philosophy guiding the AP1000 design is to ensure that exposures are ALARA by designing structures, systems, and components to achieve the following objectives:

- Attain optimal reliability and maintainability, thereby reducing maintenance requirements for radioactive components.
- Reduce radiation fields, thereby allowing operations, maintenance, and inspection activities to be performed in reduced radiation fields.
- Reduce access, repair, and equipment removal times, thereby reducing the time spent in radiation fields.
- Accommodate remote and semi-remote operation, maintenance, and inspection, thereby reducing the time spent in radiation fields.

In addition, DCD Tier 2, Section 12.1.2 describes several design features which satisfy the objectives of the plant's radiation protection program:

- The use of highly reliable equipment reduces the frequency of maintenance and associated personnel exposure.
- Except in limited applications where it is necessary for reliability considerations, materials in contact with the reactor coolant system (RCS) have low concentrations of cobalt and nickel. This reduces the amounts of cobalt-60 and cobalt-58 introduced in the RCS. (Cobalt-60 and cobalt-58 are the major sources of radiation exposure during shutdown, maintenance, and inspection activities at light water reactors (LWRs).)
- Adequate spacing and laydown areas facilitate access for maintenance and inspection.
- The amount of time spent in radiation areas is minimized with enhanced servicing convenience for anticipated maintenance or potential repairs, including ease of disassembly and modularization of components for replacement or removal to a lower radiation area for repair.
- Radioactive systems are separated from non-radioactive systems, and high radiation sources are located in separate shielded cubicles.

- Equipment requiring periodic servicing or maintenance (e.g., pumps, valves, and control panels) are separated from sources with higher radioactivity such as tanks and piping.
- Valves located in high radiation areas are equipped with reach rods or motor operators to minimize operator exposure.
- Equipment and piping are designed to minimize the accumulation of radioactive materials.
- Drains are located at low points.
- Piping is seamless, and the number of fittings is minimized, thereby reducing the radiation accumulation at seams and welds.
- Use of flushing connections minimizes the buildup of crud in system components.
- Systems that produce radioactive waste are located close to radwaste processing systems to minimize the length of piping runs carrying highly radioactive material.
- Pipes that carry resin slurries are run vertically as much as possible and large-radius bends are used instead of elbows, thereby minimizing the potential for pipe plugging.

These design considerations incorporate the basic management philosophy guiding the AP1000 design effort and are consistent with the guidelines in RG 8.8. Therefore, the staff finds them to be acceptable.

In addition to the features described above, the AP1000 reactor design incorporates several features that represent improvements over many currently operating plants:

- The AP1000 design accommodates the use of robotic technology to perform maintenance and surveillance in high radiation areas.
- The design reduces the number of components containing radioactive fluids and clearly and deliberately separates clean areas from potentially contaminated areas.
- The design eliminates the need for waste and recycle evaporators and the boron recycle system, which have historically required frequent operational and maintenance attention, exposing plant personnel to substantial levels of radiation.

The design features described in DCD Tier 2, Section 12.1.2 are intended to minimize personnel exposures and comply with the guidelines of RG 8.8. As such, these design features should maintain individual doses and total person-rem doses to plant workers and to members of the public ALARA, while maintaining individual doses within the limits of 10 CFR Part 20. The staff therefore finds these design features to be acceptable.

12.2.3 Operational Considerations

Operational considerations regarding the implementation of a radiation protection program are outside the scope of this design certification review. The applicant has stated that a COL applicant who references the AP1000 certified design will address operational considerations consistent with the level of detail provided in Revision 3 of RG 1.70. Section 12 of the SRP lists the following RGs that the COL applicant must address:

- RG 8.2, "Guide for Administrative Practices in Radiation Monitoring," February 1973
- RG 8.20, "Applications of Bioassay for I-125 and I-131," Revision 1, September 1979
- RG 8.26, "Applications of Bioassay for Fission and Activation Products," September 1980
- RG 8.27, "Radiation Protection Training for Personnel at Light-Water Cooled Nuclear Power Plants," March 1981
- RG 8.28, "Audible-Alarm Dosimeters," August 1981

Since the issuance of Chapter 12 of the SRP in 1981, the staff has revised some existing RGs and has developed additional RGs to address new issues that have resulted from the major revision of 10 CFR Part 20 in 1991. Some of the new or revised RGs that pertain to DCD Tier 2, Chapter 12 are listed below:

- RG 8.7, "Instructions for Record Keeping and Recording Occupational Radiation Exposure Data," Revision 1, June 1992
- RG 8.9, "Acceptable Concepts, Models, Equations, and Assumptions for a Bioassay Program," Revision 1, July 1993
- RG 8.13, "Instruction Concerning Prenatal Radiation Exposure," Revision 3, June 1999
- RG 8.15, "Acceptable Programs for Respiratory Protection," Revision 1, October 1999
- RG 8.25, "Air Sampling in the Work Place," Revision 1, June 1992
- RG 8.29, "Instructions Concerning Risks from Occupational Radiation Exposure," Revision 1, February 1996
- RG 8.34, "Monitoring Criteria and Methods to Calculate Occupational Radiation Doses," July 1992
- RG 8.35, "Planned Special Exposures," June 1992
- RG 8.36, "Radiation Dose to the Embryo/Fetus," July 1992

- RG 8.38, "Control of Access to High and Very High Radiation Areas in Nuclear Power Plants," June 1993

Addressing the above RGs is outside the scope of this design certification review. In DCD Tier 2, Section 12.1.3, the applicant stated that the COL applicant will address operational considerations of the SRP consistent with the level of detail provided in RG 1.70. The applicant also listed the following RGs that the COL applicant will need to address in its application—8.2, 8.7, 8.9, 8.13, 8.15, 8.20, 8.25, 8.26, 8.27, 8.28, 8.29, 8.34, 8.35, 8.36, and 8.38. The staff identified this issue as COL Action Item 12.2.3-1.

12.2.4 Conclusion

Based on the information supplied by the applicant, as described above, the staff concludes that the AP1000 design features meet the criteria of Section 12.1 of the SRP. These design features are intended to maintain individual doses and total person-rem doses to plant workers and to members of the public ALARA, while maintaining individual doses within the limits of 10 CFR Part 20. Therefore, the staff finds the AP1000 design features to be acceptable. The COL applicant will address the policy and operational considerations for the AP1000. The staff finds it acceptable for the applicant to defer discussion of the material addressed by COL Action Items 12.2.1-1 and 12.2.3-1. The staff will determine compliance with the requirements of 10 CFR Part 20 in these areas during the COL review.

12.3 Radiation Sources

The staff reviewed the descriptions of the radiation sources given in DCD Tier 2, Chapter 11, "Radioactive Waste Management," and DCD Tier 2, Section 12.2, "Radiation Sources," to assess completeness against the guidelines in RG 1.70 and the criteria in Section 12.2 of the SRP. The applicant will use the contained source terms described in the DCD as the basis for the radiation design calculations (shielding and equipment qualification) and personnel dose assessment. The applicant will use the airborne radioactive source terms in the DCD in the design of ventilation systems and for assessing personnel dose. The staff reviewed the source terms in the DCD to ensure that the applicant had either committed to follow the guidelines of the RGs and staff positions set forth in Section 12.2 of the SRP, or provided acceptable alternatives. Where the DCD adheres to these RGs and staff positions, the staff can conclude that the relevant requirements of 10 CFR Part 20 and 10 CFR Part 50, Appendix A (General Design Criterion (GDC) 61, "Fuel Storage and Handling and Radioactivity Control") have been met.

12.3.1 Contained Sources

In DCD Tier 2, Section 12.2.1, "Contained Sources," the applicant describes the shielding design source terms during normal full-power operation, shutdown, and design basis accident events. To calculate these shielding design source terms, the applicant assumed 0.25-percent fuel cladding defects at full-power operation. Other than the reactor core, the RCS is the principal contributor to radiation levels in the containment. Sources of radiation in the RCS include the following:

- fission products (which are released from defective fuel cladding)
- activation products
- corrosion products

Of these radiation sources, the activation product nitrogen-16 (N-16) is the predominant radionuclide in the RCS piping, reactor coolant pumps (RCPs), and steam generators (SGs) (all of which are located in containment) during plant operations. Containment access, however, is not normally required during power operation of the AP1000, and the applicant does not anticipate access to the loop compartments. The nitrogen-16 activity is not a factor in the radiation sources for systems and components located outside containment during normal power operations because of the short half-life (7.11 seconds) of N-16. In addition, the normal letdown flow path is entirely inside containment.

The applicant used the design basis source term values for the various radionuclides in determining the shielding design necessary to obtain the desired plant area radiation levels for the AP1000. In arriving at the design basis corrosion product activity levels for the AP1000, the applicant used a set of values that are reasonably conservative relative to current operating plant experience. The AP1000 design basis source term values (values used to determine the shielding thickness) for the major corrosion product nuclides exceed the average operating four-loop plant measured values by factors in the range of 2 to 7.

In accordance with the criteria set forth in Section 12.2 of the SRP, DCD Tier 2, Section 12.2.1 describes all large contained sources of radiation which are used as the basis for designing the radiation protection program and completing shield design calculations. These sources include the reactor core; the RCS; the chemical and volume control system; spent fuel and the spent fuel pool cooling system; the liquid, gaseous, and solid radwaste systems; and other miscellaneous sources. For each of these contained sources, the applicant provided either the source strength by energy group or the associated maximum activity levels listed by isotope. The DCD provides system layouts within rooms or cubicles, as well as information about the type and size of components in these systems. In its response to staff request for additional information (RAI) 471.007, the applicant provided additional clarifying information on dimensions, volumes, material, and equipment self-shielding for dominant radiation sources within the plant.

Section 12.2 of the SRP also states that this section should include descriptions of any required radiation sources containing byproduct, source, and special nuclear materials. In DCD Tier 2, Section 12.2.3, "Combined License Information," the applicant stated that the COL applicant will address any contained radiation sources not identified in DCD Tier 2, Section 12.2.1, including radiation sources used for instrument calibration or radiography. The staff identified this issue as COL Action Item 12.3.1-1.

The AP1000 core activity release model for a core melt accident is based on the source term model from NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants."

The applicant used the resulting source strengths to calculate post-accident dose rates, as well as worker doses incurred during vital area access/activities following an accident. In the event of core degradation, core cooling would be provided by the passive core cooling system, which is totally inside the containment such that no high activity sump solution would be recirculated outside the AP1000 containment. The use of the NUREG-1465 source term model complies with the requirements of 10 CFR 50.34(f)(2)(vii). Therefore, the staff finds the use of this accident source term acceptable.

The DCD also includes the assumptions that the applicant used in arriving at quantitative values for contained and airborne source terms, based on the relevant requirements of GDC 61 and 10 CFR Part 20.

12.3.2 Airborne Radioactive Material Sources

In DCD Tier 2, Section 12.2.2, "Airborne Radioactive Material Sources," the applicant described the sources of airborne radioactivity for the AP1000 reactor design. These include leakage of primary coolant and activation of naturally occurring argon in the atmosphere in containment; leakage from stored spent fuel assemblies and evaporative losses from the spent fuel pool in the fuel-handling area; and primary equipment leakage in the auxiliary building.

The applicant uses airborne radioactive source terms in the design of ventilation systems and for personnel dose assessment. RG 1.70 states that DCD Tier 2, Section 12.2 should include a tabulation of the calculated concentrations of airborne radioactive material, by nuclide, for areas normally occupied by operating personnel. DCD Tier 2, Section 12.2 describes the assumptions and parameters used to determine the maximum expected airborne radioactivity concentration levels during normal operations in the containment, fuel-handling area, and auxiliary building.

12.3.3 Conclusion

On the basis of its review of the information on radiation sources supplied by the applicant for the AP1000, as described above, the staff concludes that the applicant has committed to follow the guidelines of the RGs and staff positions set forth in Section 12.2 of the SRP. The staff finds that DCD Tier 2, Section 12.2 is consistent with the guidance contained in these RGs and staff positions. Therefore, the staff concludes that the relevant requirements of 10 CFR Part 20 and GDC 61 have been met. The staff finds it acceptable for the applicant to defer discussion of the material addressed by COL Action Item 12.3.1-1. Thus, the staff finds the material contained in DCD Tier 2, Section 12.2 acceptable.

12.4 Radiation Protection Design

The staff reviewed the facility design features, shielding, ventilation, and area and airborne radiation monitoring instrumentation contained in DCD Tier 2, Section 12.3, "Radiation Protection Design Features," for adherence to the guidelines in RG 1.70 and the criteria in Section 12.3-12.4 of the SRP. The purpose of this review was to ensure that the applicant had either committed to follow the guidelines of the RGs and applicable staff positions, or offered acceptable alternatives. Where the DCD adheres to these RGs and staff positions, the staff can conclude that the relevant requirements of 10 CFR Parts 20, 50, and 70 have been met. The following sections present the staff's findings.

12.4.1 Facility Design Features

The AP1000 reactor design incorporates several features to help maintain occupational radiation exposures ALARA in accordance with the guidance in RG 8.8. These design features are founded on the ALARA design considerations described in DCD Tier 2, Section 12.1 and discussed in Section 12.2.2 of this report.

The AP1000 reactor vessel design includes an integrated head package which combines the head lifting rig, control rod drive mechanisms and gray rod drive mechanisms (CRDM/GRDM), lift columns, missile shield, CRDM cooling system, and power and instrumentation cabling into a one-package reactor vessel head design. The use of this integrated head package design helps to minimize the time, manpower, and radiation exposure associated with head removal and replacement during refueling operations. The AP1000 design replaces conventional top-mounted thermocouple and movable incore flux detectors with a combination thermocouple/incore detector system. This system eliminates the need to disassemble and reassemble the instrument port conoseals at each refueling. This task has historically resulted in relatively high radiation exposures. Permanently installed shielding is integral to the head package for reducing work area dose rates from the CRDM drive shafts and the thermocouple/incore detector system.

Insulation in the area of the reactor vessel nozzle welds is fabricated in sections with quick-disconnect clasps to facilitate insulation removal for weld inspection. Permanent identification markings of the insulation sections will accommodate rapid reinstallation, thereby reducing the personnel exposure associated with this task.

The AP1000 RCPs are hermetically sealed, canned motor pumps. The shaft for the impeller and rotor is contained within the reactor coolant pressure boundary. Hence, seals are not required to restrict RCS leakage out of the pump. The RCPs are designed to require infrequent maintenance and inspection. When maintenance or replacement is required, the pump can be unbolted from a flange connection for quick removal to a low radiation background work area using a specially designed pump removal cart. This will also reduce personnel exposure.

The AP1000 SGs are designed to be compatible with the use of robotic equipment for inspection and maintenance activities. The lower portion of the primary channel head is hemispherical and merges into a cylindrical portion, which mates with the tube sheet. This arrangement provides enhanced robotic access to all tubes, including those at the periphery of the tube bundle, without the need for a manned entry into the channel head. The area surrounding the SGs has adequate pull and laydown areas and permanent platforms. In addition, the SGs are provided with handholes and removable insulation. The SG manways are sized for easy entrance and exit of workers with protective clothing and to facilitate the installation and removal of tooling. These features enhance accessibility and reduce overall exposure during SG inspection and maintenance activities. To minimize the deposit of radioactive corrosion products on the channel head surfaces, and enhance the decontamination of these surfaces, the SG channel head cladding is machined or electro-polished to a smooth surface. The tube ends are designed to be flush with the tube sheet in the SG channel head to eliminate a potential crud trap. The SG design includes a sludge control system/mud drum which reduces the need for sludge lancing and minimizes tube and tube support degradation. These features enhance the ability to inspect and repair the AP1000 SGs while resulting in lower personnel exposures.

The DCD states that motor-operated, air-operated, or other remotely actuated valves will be employed where justified by the activity levels and frequency of use, to minimize personnel exposures resulting from valve operations. The piping in pipe chases is designed for a 60-year life with consideration given to corrosion and the operating environment. Pumps and associated piping are arranged to provide adequate space for access to the pumps for servicing. Pumps in radioactive waste systems will be provided with flanged connections for ease of removal. Cartridges and filter bags that accumulate radioactivity, as well as filters in radioactive liquid systems, will be provided with remote or semi-remote filter handling systems to minimize personnel exposure and radioactive release to the environment. Instrument devices are located in low radiation zones away from radiation sources, whenever practicable, and primary instrument devices located in high radiation zones are designed for easy removal to a lower radiation zone for calibration. The heating, ventilation, and air conditioning (HVAC) systems will maintain the airflow direction from areas of lower potential airborne contamination to areas of higher potential airborne contamination.

In addition to designing equipment to comply with ALARA guidelines, the AP1000 plant layout is designed to reduce personnel exposures. The design provides adequate work and laydown space at each inspection and maintenance station. In addition, it provides for rigging and lifting equipment to facilitate the removal, transport, or replacement of equipment and the use of portable shielding during maintenance activities. Adequate illumination and support services (e.g., power, compressed air, water, ventilation, and communications) will be available at work stations. Tube pull areas for components that handle radioactive fluids will be designed with curbs, drains, and coated floors to prevent the spread of contamination in the event of spills. Valves associated with highly radioactive components will be separated from other components, and will be located in shielded valve galleries. Radioactive piping will be routed through pipe chases to minimize personnel exposures. Major components in radioactive systems will be located in shielded compartments where practicable. To minimize radiation streaming through wall penetrations, the AP1000 design calls for as many wall penetrations as practicable to be located with offsets between the radioactive source and the normally accessible areas. The equipment and layout design features described above conform with the guidelines of RG 8.8 for maintaining occupational radiation exposures ALARA. Therefore, the staff finds these features acceptable.

The AP1000 design also incorporates several features to minimize the build up, transport, and deposition of activated corrosion products in the RCS and auxiliary systems. The DCD states that the AP1000 design will reduce or eliminate the use of materials containing cobalt and nickel that are in contact with reactor coolant, except in cases in which the use of these materials is necessary for reliability purposes. The DCD further states that the majority of materials exposed to high temperature reactor coolant will have cobalt impurities of no more than 0.05-weight percent cobalt. *The major use of nickel-based alloys in the RCS is in the* inconel SG tubes. Inconel SG tubing will be limited to 0.015-weight percent cobalt, while the surfaces on the inside of the SGs, other than the tubing, will have a cobalt limit of 0.10-weight percent cobalt. Materials used for rod cluster control assemblies, gray rod cluster control assemblies, and secondary source rod cladding will be Type 304 stainless steel, with an assumed maximum cobalt limit of 0.12-weight percent cobalt. Bolting materials in reactor internals and other small components in regions of high neutron flux will be limited to 0.20-weight percent cobalt. Auxiliary components, such as valves, piping, instrumentation, and welding materials, will not be limited in cobalt content, but will have average cobalt concentrations of approximately 0.20-weight percent.

The presence of antimony in RCP journal bearings in some current generation plants has increased the number of hot particles at these plants. The AP1000 design will restrict the presence of antimony to less than 1 percent in all materials that contact the RCS, and will prohibit antimony completely from the RCP and its bearings. Crud traps created in weld areas will be minimized by using butt welds. Tanks containing radioactive liquid will have drain pipes connected at the lowest part of the tank, and will have convex or sloped-bottom designs to minimize radioactivity deposition. Piping systems used to transport process resins will be designed to minimize pipe plugging by running the piping vertically as much as practicable and sloping horizontal piping runs towards the spent resin tanks. Smooth curves will replace elbows in piping runs, where practicable, to reduce potential crud traps. Welds will be made smooth to prevent crud traps from forming. Equipment and piping containing radioactive materials will have provisions for draining and flushing. These design features, which are intended to minimize the buildup, transport, and deposition of activated corrosion products in the RCS and auxiliary systems, are based on the guidelines in RG 8.8 and are, therefore, acceptable.

The applicant provided the staff with detailed drawings of the AP1000 plant layout which indicate the nine radiation zones used in the plant design. These radiation zones serve as a basis for classifying occupancy and access restrictions for various areas within the plant during normal operations and accident conditions. On this basis, the applicant establishes the maximum design dose rates for each zone, and uses these as input for shielding of the respective zones. On the basis of its review of the detailed zoning drawings, the staff concludes that the applicant's method of plant zoning, for normal operations, is consistent with the guidance in RG 1.70 and the SRP. Therefore, the staff finds this method acceptable.

As required by 10 CFR 50.34 (f)(2)(vii), an applicant must fulfill the following requirements:

- Perform radiation and shielding design reviews of spaces around systems that may, as a result of an accident, contain radioactive materials.
- Design, as necessary, adequate access to important areas and protection of safety equipment from the radiation environment.

Item II.B.2 of NUREG-0737, "Clarification of TMI Action Plan Requirements," dated November 1980, provides additional guidance on how these requirements can be met. Item II.B.2 describes source term information that should be used to calculate post-accident radiation levels. Item II.B.2 states that the post-accident plant dose rates should be such that the dose to plant personnel should not exceed 5E-2 sieverts (5 rem) whole body, or its equivalent to any part of the body, for the duration of the accident (per 10 CFR Part 50 and GDC 19—Control Room). The dose rate in areas requiring continuous occupancy should be less than 15E-5 sieverts per hour (15 millirem per hour) averaged over 30 days.

Item II.B.2 of NUREG-0737 describes a "vital area" as any area that will, or may, require occupancy to permit an operator to aid in the mitigation of, or recovery from, an accident. Item II.B.2 also recommends listing all vital areas in the plant, and providing a summary of the integrated doses to personnel for each of the plant areas requiring either continuous occupancy or infrequent access for the duration of the accident. (These doses should include exposure received while in transit between vital areas.) DCD Tier 2, Section 12.4.1.8, "Post-Accident Actions," lists all of the AP1000 vital plant areas requiring postaccident accessibility and states that all vital areas can be accessed following an accident for less than 5E-2 sieverts (5 rem) to the whole body or 5E-1 sieverts (50 rem) to the extremities. DCD Tier 2, Figure 12.3-2 contains plant radiation zone maps which reflect maximum radiation fields over the course of an accident. The applicant performed analyses that confirmed that the individual exposure limits following an accident did not exceed the applicable requirements of GDC 19. In response to staff RAI 471.009, the applicant provided verification of these analyses. The staff finds that the listing of the plant vital areas, along with these analyses, satisfies the requirements of 10 CFR 50.34(f)(2)(vii) as they apply to plant shielding of vital areas.

The information contained in DCD Tier 2, Section 12.3.1 adequately addresses the relevant requirements of 10 CFR Part 20 and 10 CFR 50.34(f)(2)(vii). Therefore, the staff finds the information contained in this section to be acceptable.

12.4.2 Shielding

The objective of the plant's radiation shielding is to minimize plant personnel and population exposures to radiation during normal operation (including AOOs and maintenance) and during accident conditions while maintaining a program of controlled personnel access to and occupancy of radiation areas. The AP1000 design also includes shielding, where required, to mitigate the possibility of radiation damage to materials.

The DCD states that radioactive components and piping will be separated from nonradioactive components and piping to minimize personnel exposure during maintenance and inspection activities. When radioactive piping must be routed through corridors or other low radiation zones, shielded pipe chases are provided. Where applicable, pumps and other support equipment for components that contain radioactive material are separated from the more highly radioactive components by locating them outside the component cubicle in separate shielded cubicles. Shielded compartments have labyrinth entrances to minimize radiation streaming directly through access openings. Penetrations are located to preclude a direct line from the radioactive source to adjacent occupied areas. Space is allocated, where needed, for the erection of temporary shielding. These shielding techniques comply with the guidelines contained in RG 8.8 for protecting plant personnel and the public against exposure from various sources of ionizing radiation in the plant. Therefore, the staff finds these techniques acceptable.

Several recent instances of overexposures, or near overexposures, have occurred at current generation pressurized-water reactors (PWRs). Potentially lethal exposures have occurred in the reactor cavity. Personnel can also be exposed to potentially lethal doses of radiation in the vicinity of the fuel transfer tube when a spent fuel assembly passes through this tube during refueling operations. Access to the fuel transfer tube for the AP1000 is through a removable concrete or steel hatch that allows access for periodic inspection of the fuel transfer tube welds. The staff has stated that the opening of this hatch should be administratively controlled (i.e., the spent fuel transfer tube should be treated as a very high radiation area under 10 CFR Part 20), and that this hatch should be locked during all spent fuel transfer operations. The applicant has stated, in DCD Tier 2, Section 12.3.5, "Combined Licensee Information," that the COL applicant will address the administrative controls for use of the design features provided to control access to radiologically restricted areas, including potentially very high radiation areas, such as the reactor cavity and the fuel transfer canal during refueling operations. The hatch to the spent fuel transfer canal will be treated as an entrance to a very high radiation area under 10 CFR Part 20 and will be locked during spent fuel transfer operations. The staff identified this issue is identified as COL Action Item 12.4.2-1.

Section 12.3.2 of the SRP states that the applicant must describe how the shielding parameters were determined, including pertinent codes, assumptions, and techniques used in the shielding calculations. The AP1000 DCD describes the shielding codes used to determine the adequacy of the station shielding design. Specifically, the applicant stated that it used the point kernel shielding code MicroShield 4 to calculate most gamma dose rates throughout the AP1000 plant. MicroShield 4 is a personal computer version of the mainframe code QAD, which is listed as an acceptable shielding code in the SRP. For complex geometries, where doses cannot be calculated using methods based on line-of-sight attenuation, such as the point kernel method, the applicant used the MCNP code. This code, which is a Monte Carlo neutron and photon transport code, is contained in the code description file of the Radiation Shielding Information Center at the Oak Ridge National Laboratory. Monte Carlo shielding codes such as this one are commonly used to calculate doses for complex geometries, such as labyrinth structures and penetrations. Therefore, the staff finds the use of this shielding code to be acceptable to evaluate the adequacy of the AP1000 station shielding design.

The information contained in DCD Tier 2, Section 12.3.2 adequately addresses the relevant requirements of 10 CFR Part 20, 10 CFR 50.34(f)(2)(vii), and GDC 61. Therefore, the staff finds the information contained in this section to be acceptable.

12.4.3 Ventilation

RG 8.8 contains guidance on acceptable ventilation design features to control airborne radioactivity levels and maintain personnel doses ALARA. The AP1000 ventilation systems are designed to protect personnel and equipment from extreme environmental conditions, and to ensure that personnel exposure to airborne radioactivity levels is minimized and maintained ALARA and within the applicable limits of 10 CFR Part 20. Further, the design ensures that the dose to control room personnel during accident conditions will not exceed the limits specified in GDC 19—Control Room.

The source of airborne radioactivity for a room or area is primarily from equipment leakage within the specified area. The AP1000 design incorporates the following features to minimize this leakage and thereby reduce the sources of airborne radioactivity.

- Ventilation air is supplied directly to the clean areas of the plant and exhausted from the potentially contaminated areas, thereby creating a positive flow of air from clean areas to potentially contaminated areas.
- Negative or positive pressure is used appropriately in plant areas to prevent exfiltration or infiltration of possible airborne radioactive contamination, respectively.
- Equipment vents and drains are piped directly to a collection system, preventing contaminated fluid from flowing across the floor to a drain and creating a potential airborne contamination problem.
- Valves under 5.08 cm (2 in.) in diameter located in the piping carrying radioactive fluids in containment, or carrying highly radioactive fluids outside containment, are hermetically sealed to preclude radioactive releases to the environment.

The AP1000 ventilation systems incorporate the following design features to minimize personnel exposures and maintain doses ALARA in accordance with the guidelines of RG 8.8.

- Ventilation fans and filters are provided with adequate access space to permit servicing and filter changeout with minimum personnel radiation exposure.
- Ventilation ducts are designed to minimize the build up of radioactive contamination within the ducts.

The requirements of 10 CFR Part 50, Appendix A (GDC 19—Control Room) state that adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposure in excess of 5 E-2 sieverts (5 rem) whole body, or its equivalent to any part of the body, for the duration of the accident. The applicant has included the main control room in its list of vital areas. As discussed in Section 12.4.1 of this report, the applicant has performed analyses to ensure that individual exposure limits following an accident in vital areas will not exceed the applicable requirements of GDC 19.

The staff concludes that the AP1000 ventilation systems are designed to protect personnel and equipment from extreme environmental conditions, and to ensure that personnel exposure to airborne radioactivity levels is minimized and maintained ALARA and within the applicable limits of 10 CFR Part 20. Further, the design ensures that the dose to control room personnel during accident conditions will not exceed the limits specified in GDC 19. On this basis, the staff finds the AP1000 ventilation systems design acceptable.

12.4.4 Area Radiation and Airborne Radioactivity Monitoring Instrumentation

The area radiation and airborne radioactivity monitors are discussed in DCD Tier 2, Section 11.5, "Radiation Monitoring."

The plant area radiation monitoring equipment alerts operators and other station personnel to changing or abnormally high radiation conditions in the plant to prevent possible personnel overexposures and aid health physics personnel in keeping worker doses ALARA. The area radiation monitors supplement the personnel and area radiation survey provisions of the AP1000 health physics program, which is described in DCD Tier 2, Section 12.5, "Health Physics Facilities Design." The area radiation monitors should comply with the applicable requirements of 10 CFR Part 20, 10 CFR Part 50, and 10 CFR Part 70, as well as the personnel radiation protection guidelines of RGs 1.97, 8.2, and 8.8.

Control room displays provide information on monitor readings, alarm set points, and operating status. The area radiation monitors are located according to the potential for significant radiation levels in an area and the expected occupancy of the area. Specifically, area monitors will be installed in the following locations:

- areas that are normally accessible and where changes in normal plant operating conditions can cause significant increases in exposure rates above those normally designated for the areas

- areas that are normally or occasionally accessible where significant increases in exposure rates might occur because of operational transients or maintenance activities

In order to inform personnel of local dose rates in the area, area radiation monitors include a local readout and audible alarm in addition to readouts and alarms in the main control room. In addition, visible alarms are located outside each monitored area so that operating personnel can see them before entering the monitored area. Section 12.3-12.4 of the SRP reference American National Standards Institute/American Nuclear Society (ANSI/ANS) Standard HPSSC-6.8.1-1981, "Location and Design Criteria for Area Radiation Monitoring Systems for Light-Water Nuclear Reactors," dated May 1981, which provides acceptable guidance on the location and design criteria of area radiation monitoring systems. The location of the area and airborne radioactivity monitors for AP1000, as described in the DCD, meets the criteria of ANSI/ANS Standard HPSSC-6.8.1-1981. Therefore, the staff finds it acceptable.

The requirements of 10 CFR 70.24 specify the use of a monitoring system capable of detecting a criticality in designated areas where specified quantities of special nuclear material are handled, used, or stored. DCD Tier 2, Section 11.5.6.4, "Fuel Handling Area Criticality Monitors," states that two fixed radiation monitors (which meet the radiation sensitivity requirements of 10 CFR 70.24 for criticality monitors) will be located to provide coverage on the operating deck level of the Annex Building where new and spent fuel will be handled. In addition, a portable radiation monitor will be used on the crane handling fuel to detect potential criticalities during fuel handling operations. The staff finds that the use and location of these radiation monitors satisfies the criticality accident requirements of 10 CFR 70.24 and therefore finds the use of these radiation monitors to be acceptable.

The requirements of 10 CFR 50.34(f)(2)(xvii) (corresponding to Item II.F.1(3) of NUREG-0737) specify, in part, that the control room must include instrumentation to measure, record, and read out containment radiation intensity (high level). Further guidance is provided in Item II.F.1(3) of NUREG-0737, which states that the reactor containment must be equipped with two physically separate radiation monitoring systems that are capable of measuring up to 10^5 Gray per hour (10^7 roentgen per hour) in the containment following an accident. In DCD Tier 2, Section 11.5.6.2, "Post Accident Area Monitors," the applicant stated that the AP1000 design incorporates four electrically independent ion chambers located inside the containment to measure high range gamma radiation. These detectors will be mounted on the inner containment wall in widely separated locations, and will have an unobstructed "view" of a representative volume of the containment atmosphere. The design and qualification of these monitors complies with the guidelines of RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3, dated May 1983, and NUREG-0737, Item II.F.1(3), with respect to detector range, response, redundancy, separation, onsite calibration, and environmental design qualification. The staff, therefore, finds these monitors to be acceptable.

The airborne radiation monitoring equipment will be placed in selected areas and ventilation systems to give plant operating personnel continuous information about the airborne radioactivity levels throughout the plant. The airborne radioactivity monitors are located upstream of the filter trains to monitor representative radioactivity concentrations from the areas being sampled. The airborne radiation monitoring system, as described in the DCD, meets the scope of the post-accident monitoring requirements set forth in 10 CFR Part 50, GDC 64, "Monitoring Radioactivity Releases," and the guidance of RG 1.97. Therefore, the staff finds the system acceptable.

Section 12.3 of the SRP states that airborne radioactivity monitors shall be able to detect the time integrated change of the most limiting particulate and iodine species equivalent to those concentrations specified in Appendix B of 10 CFR Part 20 (one derived air concentration (DAC)) in each monitored plant area within 10 hours (i.e., monitors should be sensitive enough to measure 10 DAC-hours). DCD Tier 2, Section 11.5.2.3, "Monitor Descriptions," states that those airborne radioactivity monitors which monitor plant areas which may be occupied by plant personnel will be capable of detecting 10 DAC-hours.

Section 12.3 of the SRP states that the DCD must provide the criteria and methods for obtaining representative in-plant airborne radioactivity concentrations in all work areas. Further, Item III.D.3.3 of NUREG-0737 (corresponding to 10 CFR 50.34(f)(2)(xxvii)) states that each applicant should provide equipment and associated training and procedures for accurately determining the airborne iodine concentrations in areas within the facility where personnel may be present during an accident. The applicant has stated, in DCD Tier 2, Section 12.3.5, "Combined Licensee Information," that the COL applicant will address the criteria and methods for obtaining representative measurements of radiological conditions, including airborne radioactivity concentrations in work areas (Item III.D.3.3 of NUREG-0737). The COL applicant will also address the use of portable instruments, and the associated training and procedures, to accurately determine the airborne concentrations in areas within the facility where plant personnel may be present during an accident. The staff has identified this issue as COL Action Item 12.4.4-1.

The staff concludes that the area radiation and airborne radioactivity monitors described in the AP1000 DCD comply with the applicable requirements of 10 CFR Parts 20, 50, and 70, as well as the personnel radiation protection guidelines of RGs 1.97, 8.2, and 8.8. These monitors are designed to monitor both area and airborne radioactivity levels in the plant to ensure that doses to plant personnel are maintained ALARA. Therefore, the staff finds that these monitoring systems are acceptable.

12.4.5 Conclusion

On the basis of its review of the information on radiation protection design (including facility design features, shielding, ventilation, and area radiation and airborne radioactivity monitoring instrumentation) supplied by the applicant for the AP1000, as described above, the staff concludes that the applicant has committed to follow the guidelines of the RGs and staff positions set forth in Section 12.3-12.4 of the SRP. Because the DCD adheres to these RGs and staff positions, the staff concludes that the relevant requirements of 10 CFR Parts 20, 50, and 70 have been met. The staff finds it acceptable for the applicant to defer discussion of the material addressed by COL Action Items 12.4.2-1 and 12.4.4-1. The staff, therefore, finds the material contained in DCD Tier 2, Section 12.3 acceptable.

12.5 Dose Assessment

The staff reviewed the applicant's dose assessment contained in DCD Tier 2, Section 12.4, "Dose Assessment," for completeness against the guidelines in RG 1.70 and the criteria set forth in Section 12.3-12.4 of the SRP. The staff ensured that the applicant had either committed to follow the criteria of the applicable RGs and staff positions set forth in Section 12.3-12.4 of NUREG-0800, or provided acceptable alternatives. Where the DCD adheres to these RGs and staff positions, the staff can conclude that the relevant requirements of 10 CFR Part 20 have been met. In addition, the staff selectively compared the applicant's dose assessment, for specific functions and activities, against the experience of operating PWRs. (Radiation exposures to operating personnel shall not exceed the occupational dose limits specified in 10 CFR 20.1201.)

In DCD Tier 2, Section 12.4, "Dose Assessment," the applicant provided an assessment of the annual occupational radiation dose that would be received by the operating staff of an AP1000 facility. DCD Tier 2, Tables 12.4-1 through 12.4-12 provide estimated doses for various jobs and inspections that would be performed in the plant during maintenance and refueling periods, as well as for power operations. These activities result in an estimated total annual dose of 0.671 person-sievert (67.1 person-rem). DCD Tier 2, Section 12.4 does not contain a separate determination of doses attributable to airborne activity; however, experience at operating LWRs demonstrates that the dose from airborne radioactivity is not a significant contribution to the total dose.

In performing the dose assessment, the applicant reviewed exposure data from operating plants to obtain a breakdown of the doses incurred within each dose assessment category referenced in RG 8.19, "Occupational Radiation Dose Assessment in Light-Water Reactor Power Plants—Design Stage Man-Rem Estimates," Revision 1, dated June 1979. The applicant then adjusted these values to account for AP1000 design features. Based on its calculations, the applicant obtained an estimated annual dose of 0.671 person-sievert (67.1 person-rem).

The cumulative annual dose of 0.671 person-sievert (67.1 person-rem) for operating an AP1000 plant is consistent with the Electric Power Research Institute design guideline of 1.0 person-sievert (100 person-rem) per year and compares favorably with the average current PWR experience (the 2002 average collective dose for U.S. PWRs was 0.87 person-sievert (87 person-rem)). Although the applicant's dose assessment for the AP1000 is not in the format specified in RG 8.19, it is a detailed dose assessment that meets the intent of RG 8.19, and, therefore, the staff finds it acceptable.

As discussed above, the AP1000 design incorporates several improvements over current operating PWR designs. These improvements are intended to significantly reduce the personnel exposure associated with operational and maintenance activities. The occupational radiation exposure resulting from unscheduled repairs on valves, pumps, and other components will be lower for the AP1000 than for current plant designs because of the reduced radiation fields, increased equipment reliability, and reduced number of components relative to currently operating plants. Historically, special maintenance performed on SGs has resulted in significant personnel doses. The applicant estimates that the annual dose incurred for special maintenance of the AP1000 SGs will be slightly more than 0.01 person-sievert (1 person-rem). These low estimated SG doses result from improved SG design and improved primary and secondary water chemistry controls. The applicant does not predict that any special maintenance activities will be required for the canned motor RCPs used in the AP1000 design.

The AP1000 radwaste system design incorporates a less complicated approach to waste processing than do current generation PWRs. The AP1000 does not use waste or boron recycle evaporators and does not have a catalytic hydrogen recombiner in the gaseous radwaste system. Elimination of these high maintenance components should contribute significantly to lower anticipated doses associated with waste processing activities for the AP1000 design.

Since the refueling process is labor intensive, detailed planning and coordination are essential in order to maintain personnel doses ALARA. The AP1000 design incorporates advanced technology (e.g., integrated reactor vessel head package, combination thermocouple and flux detectors, permanent reactor cavity seal ring, and "pass and one-half" stud tensioning procedures) into the refueling process, thereby reducing personnel doses during refueling operations.

The direct radiation at the site boundary from the containment and other plant buildings is negligible. The containment shield building walls are a minimum of 0.91 m (3 ft) thick, reducing radiation levels outside the containment to less than 2.5 microsieverts per hour (0.25 millirem per hour) from sources inside containment. The AP1000 design also provides storage for refueling water inside the containment, instead of in an outside storage tank, thereby eliminating the refueling water storage tank as an offsite radiation source.

The staff finds that the dose assessment for the AP1000 complies with the guidelines in RG 1.70 and the criteria set forth in Section 12.3-12.4 of the SRP. This dose assessment also meets the intent of RG 8.19. By addressing the anticipated occupational radiation exposures due to normal and anticipated inspection and maintenance, and by incorporating design features to reduce occupational radiation exposures, the applicant has shown that the AP1000 is designed to operate within the occupational dose limits specified in 10 CFR 20.1201. The staff, therefore, finds the material contained in DCD Tier 2, Section 12.4 acceptable.

12.6 Health Physics Facilities Design

The requirements in 10 CFR 20.1101 state that each licensee shall develop, document, and implement a radiation protection program commensurate with the scope and extent of licensed activities and sufficient to ensure compliance with the provisions of 10 CFR Part 20. Section 12.5 of RG 1.70 and the SRP state that the operational aspects of an acceptable radiation protection program should address the following three areas:

- organization
- equipment, instrumentation, and facilities
- procedures

DCD Tier 2, Section 12.5, "Health Physics Facilities Design," addresses the objectives and design of the AP1000 health physics facilities. The applicant stated that the COL applicant will address the organizational and procedural aspects of the AP1000 radiation protection program.

The health physics facilities are designed with the objectives of:

- Providing capability for administrative control of the activities of plant personnel to maintain personnel exposure to radiation and radioactive materials ALARA and within the requirements of 10 CFR Part 20.

- Providing capability for administrative control of effluent releases from the plant to maintain the releases ALARA and within the limits of 10 CFR Part 20 and plant Technical Specifications.

- Providing capability for administrative control of waste shipments from the plant to meet applicable requirements for the shipment and receipt of the material at the storage or burial site.

DCD Tier 2, Section 12.5 describes the equipment and facilities contained in the AP1000 design, including a discussion of whole body and portable survey instrumentation. The DCD also discusses the facilities that are displayed on the plant layout drawings, and describes the traffic flow patterns that personnel would take through the health physics access control area for access to and from the radiation control area. The plant will be designed so that significant radiation sources are minimized, locally shielded, and/or located in shielded cubicles in order to maintain doses to plant personnel ALARA. Area radiation monitoring equipment with local alarms will provide plant personnel with an indication of plant radiation levels. The ventilation system is designed to minimize the spread of airborne radioactivity. For radiation protection purposes, areas in the plant are classified as nonradiation areas and restricted radiologically controlled areas. Restricted areas are further categorized as radiation areas, high radiation areas, very high radiation areas, airborne radioactivity areas, and radioactive materials areas. These categorizations comply with 10 CFR Part 20. The AP1000 health physics facilities comply with the guidance contained in RG 8.8 and are designed to ensure that personnel radiation exposures will be maintained ALARA and within the dose limits of 10 CFR Part 20.

DCD Tier 2, Section 12.5 contains a description of how the health physics facilities have been designed to maintain personnel exposure to radiation and radioactive materials ALARA and within the requirements of 10 CFR Part 20. The staff, therefore, finds the description of the health physics facilities described in DCD Tier 2, Section 12.5 acceptable. However, the applicant makes no reference in this section of the DCD to the organization or procedures that will be used to ensure that personnel radiation exposures will be maintained ALARA. The applicant stated, in DCD Tier 2, Section 12.5.5, "Combined Licensee Information," that the COL applicant will address the organization and procedures used for adequate radiological protection and will provide methods to maintain personnel radiation exposures ALARA. The staff has identified this issue as COL Action Item 12.6-1.

13. CONDUCT OF OPERATIONS

13.1 Organizational Structure of the Applicant

In the AP1000 Design Control Document (DCD) Tier 2, Section 13.1, "Organization Structure of Applicant," the applicant stated that the organizational structure is the responsibility of the Combined License (COL) applicant. The applicant also stated that the organizational structure should be consistent with the human system interface. The staff discusses its evaluation of this matter in Sections 18.2, 18.6, and 18.10 of this report. In DCD Tier 2, Section 13.1.1, "Combined License Information Item," the applicant stated that a COL applicant referencing the AP1000 certified design will address the adequacy of the organizational structure. The staff finds this to be acceptable. This is COL Action Item 13.1-1.

13.2 Training

In DCD Tier 2, Section 13.2, the applicant stated that the COL applicant will be responsible for training programs. The applicant further referenced WCAP-14655, which describes the input from the designer on the training of operations personnel who participate as subjects in the human factors engineering verification and validation. The staff discusses its evaluation of this matter in Section 18.10 of this report. In DCD Tier 2, Section 13.2.1, "Combined License Information Item," the applicant stated that a COL applicant referencing the AP1000 certified design will develop and implement training programs for plant personnel. The staff finds this to be acceptable. This is COL Action Item 13.2-1.

13.3 Emergency Planning

13.3.1 Introduction

The staff reviewed DCD Tier 2, Section 13.3, "Emergency Planning." The staff issued requests for additional information (RAIs 472.001, 472.002, and 472.003 in a letter dated September 19, 2002, and requested further additional information (RAI 472.003, Revision 1) in a letter dated April 9, 2003. The staff also conducted a telephone conference with the applicant on April 9, 2003. The applicant responded to the initial request for additional information in a letter dated October 2, 2002, and to the subsequent RAI in an email on April 11, 2003.

The AP1000 Draft Safety Evaluation Report (DSER) was issued by the NRC on June 16, 2003, and identified two open items for emergency planning (EP). The two open items were associated with technical support center (TSC) habitability, and relocation of TSC functions to the emergency operations facility (EOF) upon loss of TSC habitability. In addition, the staff also identified an issue with the COL action item associated with the programmatic responsibility of a COL applicant for EP.

The applicant responded to the two EP open items in a letter dated July 7, 2003. The staff met with the applicant in a public meeting on July 10, 2003, and discussed the details and the resolution of the two EP open items. The staff subsequently conducted a telephone conference with the applicant on July 29, 2003, and the applicant submitted revised responses to the EP open items in a July 31, 2003, letter.

A significant change in EP requirements for the AP1000, as compared to the AP600 design, was the elimination of various postaccident sampling system (PASS) requirements. The AP600 Final Safety Evaluation Report (FSER) reflected the NUREG-0737 PASS criteria as a COL action item. Subsequently, on October 31, 2000, the U.S. Nuclear Regulatory Commission (NRC) published the model safety evaluation in the Federal Register (65 FR 65018), which eliminated various requirements on post-accident sampling imposed on licensees through orders, license conditions, or technical specifications. Section 13.3.3.4.1 of this report discusses the model safety evaluation, as it applies to EP for the AP1000.

13.3.2 Emergency Planning Responsibilities

The following regulations, guidance, and standards apply to EP responsibilities.

The requirements of Title 10, Section 52.79(d), of the Code of Federal Regulations (10 CFR 52.79(d)) state that a COL application must contain emergency plans which provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at the site. The requirements of 10 CFR 52.79(b) state that the COL application must contain the technically relevant information required of applicants for an operating license by 10 CFR 50.34. The requirements of 10 CFR 50.34(b)(6)(v) state that the application shall include information concerning facility operation, including plans for coping with emergencies, which shall include the items specified in 10 CFR Part 50, Appendix E. The requirements of 10 CFR 50.34(f)(2) specify that the COL applicant shall provide sufficient information to demonstrate that various required actions will be satisfactorily completed by the operating license stage. Specifically, 10 CFR 50.34(f)(2)(viii) requires a capability to promptly obtain and analyze samples from the reactor coolant system and containment that may contain accident source term radioactive materials, while ensuring that no individual receives radiation exposure in excess of 0.05 Sv (5 rem) to the whole body or 0.5 Sv (50 rem) to the extremities. In addition, 10 CFR 50.34(f)(2)(xxv) requires an onsite TSC and onsite operational support center (OSC). Finally, the COL applicant must comply with the applicable requirements of 10 CFR 50.47, "Emergency Plans."

Compliance with these regulations is determined by utilizing the guidance in Regulatory Guide (RG) 1.101, "Emergency Planning and Preparedness for Nuclear Power Reactors" (Revision 4, July 2003), which endorses Revision 1 of NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants" (Revision 1, November 1980), and through it NUREG-0696, "Functional Criteria for Emergency Response Facilities—Final Report" (February 1981), NUREG-0737 and Supplement 1 to NUREG-0737, "Clarification of TMI Action Plan Requirements—Requirements for Emergency Response Capability" (Generic Letter (GL) 82-33, December 17, 1982).

DCD Tier 2, Section 13.3, indicates that EP is the responsibility of the COL applicant. Additionally, it states that communication interfaces among the main control room (MCR), the TSC, and the EP centers are the responsibility of the COL applicant.

The staff agrees that the COL applicant referencing the AP1000 design will address EP, and EP information submitted in the application will significantly depend on plant- and site-specific characteristics. Emergency planning basically consists of facilities, equipment, personnel, and training. The majority of EP requirements are programmatic in nature and supplement physical facilities and equipment. Later parts of this chapter address those aspects of physical facilities and equipment associated with EP that should be considered in the standard design. DCD Tier 2, Section 13.3.1, "Combined License Information Item," states the following:

> Combined License applicants referencing the AP1000 certified design will address emergency planning including post-72 hour actions and its communication interface.

The reference to post-72-hour actions is associated with the 72-hour battery bank (i.e., the second battery bank in Divisions B and C), which is used for loads requiring power for 72 hours following an event of loss of all alternating current (ac) power sources concurrent with a design-basis accident (DBA). The staff finds that this is acceptable, in that it complies with the requirements of 10 CFR 52.79(d) and the applicable portions of 10 CFR Part 50. It is consistent with the extent to which the COL applicant can more appropriately address certain EP design features, facilities, functions, and equipment. This is COL Action Item 13.3-1.

13.3.3 TSC/OSC/Decontamination Facility

Although the COL applicant will address many aspects of EP, the standard design must consider certain design features, facilities, functions, and equipment necessary for EP. Specifically, in accordance with 10 CFR 50.34(f)(2)(xxv), the standard design must address the characteristics of the onsite TSC and onsite OSC. The design should include adequate emergency facilities and equipment to support emergency response, in accordance with 10 CFR 50.47(b)(8) and Subsection IV.E.8 to 10 CFR Part 50, Appendix E. The design should also include an onsite decontamination facility, in accordance with 10 CFR 50.47(b)(11) and Subsection IV.E.3 to 10 CFR Part 50, Appendix E, to provide the capability for controlling radiological exposures and providing decontamination facilities for onsite individuals, respectively.

In addition, 10 CFR 50.47(b)(9) requires adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition; 10 CFR 50.47(b)(11) requires the establishment of the means for controlling radiological exposures to emergency workers; and 10 CFR 50.34(f)(2)(viii) requires that the standard design provide the capability to promptly obtain and analyze samples from the reactor coolant system and containment, which may contain accident source term radioactive materials, without radiation exposures to any individual exceeding 0.05 Sv (5 rem) to the whole body or 0.5 Sv (50 rem) to the extremities. The guidance in RG 1.101 determines compliance with these regulations.

13.3.3.1 <u>General Description of Facilities</u>

DCD Tier 2, Section 18.8.3.5, "Technical Support Center Mission and Major Tasks," and Section 18.8.3.6, "Operational Support Center Mission and Major Tasks," describe the mission and major tasks of the TSC and OSC, respectively, for the AP1000 standard design. The TSC is to provide an area and resources for use by personnel providing plant management and technical support to the plant operating staff during emergency evolutions. The TSC relieves the reactor operators of peripheral duties and communications not directly related to reactor system manipulations, and prevents congestion in the control room. The OSC is to provide a centralized area and the necessary supporting resources for the assembly of predesignated operations support personnel during emergency conditions. The TSC and OSC are in different locations in the annex building. The TSC is located in the annex building at Elevation 117'-6", adjacent to the passage from the annex building to the nuclear island control room, as shown in DCD Tier 2, Figure 1.2-19, "Annex Building General Arrangement Plan at Elevation 117'-6" & 126'-3"." The TSC is identified as the Main TSC Operations Area (Room 40403). The OSC location, identified as the ALARA [as low as is reasonably achievable] Briefing Room & Operational Support Center (Room 40318), is shown as such in DCD Tier 2, Figure 1.2-18, "Annex Building General Arrangement Plan at Elevation 100'-0" & 107'-2"."

In RAI 472.002, the staff asked the applicant to explain why Figure 1.2-18, which shows the hot machine shop, depicts no decontamination facilities, while DCD Tier 2, Section 1.2.5, "Annex Building," indicates that the hot machine shop includes decontamination facilities. The applicant responded that the hot machine shop (Room 40358) will include a variety of equipment for servicing radiologically controlled area equipment, including a lathe, a power hacksaw, and a power band saw. Also included will be a permanent diked decontamination basin with a grating support floor, connected to the radioactive waste drain system for cleaning contaminated components. The hot machine shop will also contain a "portable decontamination system," which the COL holder will purchase according to specifications of its choosing. Personnel decontamination will be performed in a separate decontamination room (Room 40355), which will include two personnel showers and two sinks connected to the radioactive liquid waste system.

The staff concludes that the information provided in the AP1000 DCD pertaining to the TSC, OSC, and decontamination room is consistent with the guidance identified in RG 1.101. Thus, the staff finds that the applicant's design meets the applicable requirements of 10 CFR 50.34(f)(2)(xxv), 10 CFR 50.47(b)(8), 10 CFR 50.47(b)(11), and Subsections IV.E.3 and IV.E.8 to 10 CFR Part 50, Appendix E.

13.3.3.2 Technical Support Center Size

The guidance of Section H.1 of NUREG-0654/FEMA-REP-1, Revision 1, calls for the establishment of a TSC in accordance with NUREG-0696. NUREG-0696 states that the TSC shall be large enough to provide working space, without crowding, for the personnel assigned to the TSC at the maximum level of occupancy. Specifically, the TSC working space shall be sized for a minimum of 25 persons, with a minimum working space of approximately 7 m^2 (75 ft^2) per person. The guidance also calls for sufficient space for equipment and storage, as well as to perform certain repair and other TSC-related activities. In addition, Paragraph 8.2.1.c of Supplement 1 to NUREG-0737, which is consistent with NUREG-0696, states that the TSC will be sufficient to accommodate and support NRC and licensee predesignated personnel, equipment, and documentation.

DCD Tier 2, Section 18.8.3.5 describes the design considerations for the TSC. In that section, the applicant stated that the size of the TSC complies with the size criteria of NUREG-0696. DCD Tier 2, Section 9.4.1.2.1.1, "Main Control Room/Technical Support Center HVAC [heating, ventilation and air conditioning] Subsystem," further states that the TSC areas consist of the main TSC operations area, conference rooms, NRC room, computer rooms, shift turnover room, kitchen/rest area, and restrooms.

The staff concludes that the information provided in the DCD pertaining to the TSC size is consistent with the guidance identified in RG 1.101. Specifically, the area conforms with the size specifications of NUREG-0696 and is sufficient to accommodate and support NRC and licensee predesignated personnel, equipment, and documentation, in conformance with Supplement 1 to NUREG-0737. As such, the staff finds that this information meets the applicable requirements of 10 CFR 50.47(b)(8) and Subsection IV.E.8 to 10 CFR Part 50, Appendix E, and is, therefore, acceptable.

13.3.3.3 Technical Support Center Habitability

In DCD Tier 2, Section 18.8.3.5, the applicant stated that, consistent with NUREG-0737, the TSC has no emergency habitability requirements. In addition, it stated that the TSC complies with the habitability requirements of Supplement 1 to NUREG-0737, when electrical power is available. Paragraph 8.2.1.f of Supplement 1 to NUREG-0737 calls for the TSC to be provided with the following equipment:

> radiological protection and monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem [0.05 Sv] whole body, or its equivalent to any part of the body, for the duration of the accident.

Item II.B.2 of NUREG-0737 states that the TSC is considered vital after an accident and that the design dose rate for personnel in a vital area should be such that doses do not exceed the guidelines of General Design Criteria (GDC) 19 during an accident. In addition, GDC 19 requires adequate radiation protection, such that the dose to personnel does not exceed 0.05 Sv (5 rem) whole body, or its equivalent to any part of the body for the duration of the accident. NUREG-0696 provides more detailed criteria for emergency plans, design, and functional criteria for emergency response facilities, including the following habitability criteria for the TSC in Section 2.6 of NUREG-0696:

> Since the TSC is to provide direct management and technical support to the control room during an accident, it shall have the same radiological habitability as the control room under accident conditions. TSC personnel shall be protected from radiological hazards, including direct radiation and airborne radioactivity from inplant sources under accident conditions, to the same degree as control room personnel. Applicable criteria are specified in General Design Criterion 19; Standard Review Plan 6.4; and NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.B.2.

Conduct of Operations

> The TSC ventilation system shall function in a manner comparable to the control room ventilation system. The TSC ventilation system need not be seismic Category I qualified, redundant, instrumented in the control room, or automatically activated to fulfill its role. A TSC ventilation system that includes high-efficiency particulate air (HEPA) and charcoal filters is needed, as a minimum. Sufficient potassium iodide shall be provided for use by TSC and control room personnel. The capacity of the installed TSC ventilation filter system shall be independent of these thyroid-blocking provisions.
>
> If the TSC becomes uninhabitable, the TSC plant management function shall be transferred to the control room.

13.3.3.3.1 TSC Ventilation System

In a previous version of DCD Tier 2, Section 18.8.3.5, the applicant stated the following in regard to habitability-related systems and their operation under various conditions:

> When a source of ac power is available, the nuclear island nonradioactive ventilation system (VBS) provides HVAC service to the main control room and the TSC during normal and abnormal conditions. The VBS and its support systems provide these functions in a reliable and failure tolerant fashion. If offsite power is not available, backup power is automatically provided by either of the two nonsafety-related diesels within the onsite standby power system. [DCD Tier 2, Section] 9.4.1, provides additional design details of the VBS.
>
> The VBS system provides for cooling, heating, humidity control, filtration (HEPA and charcoal), and pressurization following design basis accidents except for a station blackout (loss of non-safety-related ac power, including the non-safety-related diesels). If nonsafety-related ac power is not available, including the diesels, the habitability of the main control [room] is provided by the main control room emergency habitability system (VES) as discussed in [DCD Tier 2,] Section 6.4. Although the TSC is not supplied by either the VBS or the VES during a station blackout, it still remains habitable. The doors to the TSC can be opened to aid with ventilation and control of room temperature for the two hours that the workstations continue to operate. The TSC workstations are powered from the non-Class 1E uninterruptable [sic] power supplies, therefore plant monitoring capability from the TSC exists for two hours following a station blackout.
>
> Should habitability be challenged within the TSC due to lack of cooling or a high radiation level resulting from a beyond design basis accident, the TSC personnel and the functions of the TSC are transferred to the emergency operations facility (EOF) where habitability is not dependent on plant systems and with communication and data transfer links to the main control room to provide essential exchange of information.

In a previous version of DCD Tier 2, Section 6.4, "Habitability Systems," the applicant stated the following, in part:

> The habitability systems are a set of individual systems that collectively provide the habitability functions for the plant. The systems that make up the habitability systems [include the following]:
>
> - Nuclear island nonradioactive ventilation system (VBS)
> - Main control room emergency habitability system (VES)
>
> When a source of ac power is available, the nuclear island nonradioactive ventilation system (VBS) provides normal and abnormal HVAC service to the main control room (MCR), technical support center (TSC), instrumentation and control rooms, dc equipment rooms, battery rooms, and the nuclear island nonradioactive ventilation system equipment room as described in [DCD Tier 2, Section] 9.4.1.
>
> When a source of ac power is not available to operate the nuclear island nonradioactive ventilation system or radioactivity is detected in the MCR air supply, which could lead to exceeding General Design Criterion 19 operator dose limits, the main control room emergency habitability system (VES) is capable of providing emergency ventilation and pressurization for the main control room.

Further, in a previous version of DCD Tier 2, Section 6.4.4, "Emergency Mode," stated the following:

> Automatic transfer of habitability system functions from the nuclear island nonradioactive ventilation system to the main control room emergency habitability system is accomplished by the receipt of one of two signals:
>
> - "High-high" particulate or iodine radioactivity in MCR air supply
> - Loss of ac power sources

The nonradioactive ventilation system (VBS) serves the TSC. An earlier version of DCD Tier 2, Section 9.4.1.1.2, "Power Generation Design Basis," stated, in part, that the VBS provides the following functions:

- controls the MCR and TSC relative humidity between 25 to 60 percent

- maintains the MCR and TSC at a slightly positive pressure during normal operations

- isolates the MCR and/or TSC from normal outdoor air intake and provides filtered outdoor air to pressurize the MCR and TSC upon detection of a high gaseous radioactive concentration in the MCR supply air duct

- isolates the MCR and/or TSC upon detection of a high concentration of smoke in the outside air intake

- provides smoke removal capability for the MCR and TSC

DCD Tier 2, Section 9.4.1.2.2, "Component Description," indicates that the VBS components include low-efficiency filters, high-efficiency filters, and postfilters; high-efficiency particulate air (HEPA) filters; charcoal adsorbers; and isolation dampers. A previous version of DCD Tier 2, Section 9.4.1.2.3.1, "Main Control Room/Technical Support Center HVAC Subsystem," under the section entitled "Abnormal Plant Operations," stated that when high gaseous radioactivity is detected and the HVAC subsystem is operable, both supplemental air filtration units automatically start to pressurize the MCR and TSC to at least 0.32 cm (0.125 in.) wg. The normal outside air makeup duct and the MCR and TSC toilet exhaust isolation dampers close. In addition, if ac power is unavailable for more than 10 minutes or if high-high particulate or iodine radioactivity is detected in the MCR supply air duct, which would lead to exceeding GDC 19 operator dose limits, the plant safety and monitoring system automatically isolates the MCR from the normal MCR/TSC HVAC subsystem. In the event of a loss of the normal plant ac electrical system, the MCR/TSC ventilation subsystem is automatically transferred to the onsite standby diesel generators.

13.3.3.3.2 Requests for Additional Information

In RAI 472.003, the staff asked the following:

> [DCD Tier 2,] Section 9.4.1.2.1.1 indicates that radiation monitors are located inside the main control room upstream of the supply air isolation valves and that these monitors isolate the main control room [from] the nuclear island non-radioactive ventilation system on high-high particulate or iodine radioactivity concentrations. Does this include isolating the technical support center as well?

In its response to RAI 472.003, the applicant stated the following:

> No, only the main control room is isolated on a high-high signal. At that time, the main control room emergency habitability system is placed into operation to protect the main control room operators. Please refer to "Abnormal Plant Operation" portion of DCD [Tier 2, Section] 9.4.1.2.3.1, which provides details as to the operation of the main control room and technical support center HVAC subsystem during abnormal events involving high and high-high signals.
>
> Also see [DCD Tier 2, Section] 18.8.3.5 "Technical Support Center Mission and Major Tasks" for discussions of the technical support center (TSC) including habitability and evacuation during emergencies.

The staff conducted a telephone conference on April 9, 2003, with the applicant to discuss issues associated with TSC habitability and relocation of TSC functions to the EOF under emergency conditions. Supplemental comments to RAI 472.003 that emerged from this conference include the following:

The staff has reviewed Westinghouse's response to RAI 472.003 dealing with technical support center ventilation (i.e., habitability). The response referred to the Design Control Document (DCD) sections that covered TSC ventilation and habitability. While this answered the specific RAI question, it did not address apparent incorrect statements and inconsistencies in the system design, or the justification for relocation of TSC function to the emergency offsite [sic] facility (EOF) rather than to the main control room. Below are two questions pertaining to DCD Section 18.8.3.5, and an additional question pertaining to use of the EOF when the TSC becomes uninhabitable:

1. [DCD Tier 2, Section] 18.8.3.5 states that "Consistent with NUREG 0737 . . . the technical support center has no emergency habitability requirements." In accordance with NUREG-0737, the TSC is a "vital area" and should comply with radiological habitability requirements of General Design Criteria (GDC) 19 for the duration of an accident. Please provide justification for why the TSC has no emergency habitability requirements.

2. [DCD Tier 2, Section] 18.8.3.5 states (in italics) that "The TSC complies with the habitability requirements of Reference 27 [i.e., Supplement 1 to NUREG-0737] when electrical power is available." First, Supplement 1 requires the same radiological habitability requirements as GDC 19, and thus, this statement contradicts (1), above; and second, the reference to "when electrical power is available" is but one, of two, triggering events that would automatically isolate the Main Control Room from the TSC. The second trigger is "High-high" particulate or iodine radioactivity in MCR air supply" (see [DCD Tier 2, Section] 6.4.4, page 6.4-9). Please provide justification for the inconsistencies.

3. In the event a relocation of the TSC to the EOF is allowed, rather than to the MCR (as required by NUREG-0696 guidance), how will the physical location of the EOF be addressed, as it relates to TSC support functions? There is currently a trend of utilities attempting to consolidate their EOFs for multiple plants. The physical location aspect is not addressed in the DCD, including whether the NRC would allow it. The implication is that the EOF could be anywhere, and as such, the transferred TSC functions could be anywhere.

The applicant responded with Revision 1 to RAI 472.003, which includes the following information regarding the three questions asked by the staff:

1&2 The nuclear island nonradioactive ventilation system (VBS) maintains habitability in the TSC to the requirements of GDC 19 for normal and accident scenarios as long as electrical power is available and radiation levels do not exceed a predetermined, "high-high" threshold. The VBS has two safety-related functions. The first is to monitor the air coming into the MCR and the second is to isolate the MCR envelope during a loss of electrical power of more than 10 minutes or upon a "high-high" radiation signal. As this system has no safety-related AC electrical system, it is not credited as meeting GDC 19 for the protection of the MCR operators. The safety-related MCR emergency habitability system (VES) is credited as meeting GDC 19 for the protection of the MCR operators. Thus, Westinghouse agrees that the statement, "Consistent with NUREG-0737 . . . the technical support center has no emergency habitability requirements," is confusing. The statement will be removed from [DCD Tier 2, Section] 18.8.3.5 in the next revision of the DCD. See the [DCD] Revision: section below for detail changes.

[DCD Tier 2, Section 18.8.3.5 was subsequently revised to delete the sentence: "The technical support center has no emergency habitability requirements."]

In the event of high radiation, the VBS operates in a recirculation mode filtering the air in the MCR and the TSC. In this mode, the VBS is designed to provide a capability similar to that of the engineered safety features (ESF) systems in operating plants with respect to air filtration and adsorption. Should a "high-high" radiation signal or if a station blackout of more than 10 minutes occur, the VBS stops, isolates the main control room envelop and the VES begins operation to protect the main control room operators. If the system has power and is operating, it will prevent a "high-high" radiation signal. This is the reason [DCD Tier 2, Section] 18.8.3.5 states, "The TSC complies with the habitability requirements of Reference 27 [i.e., Supplement 1 to NUREG-0737] when electrical power is available."

In practical terms, the TSC does have emergency habitability capabilities comparable to those of operating plants as long as electrical power is available either from offsite power or from the onsite diesel generators. See the response to item 3 below, for a discussion on the probability of losing both offsite power and the onsite diesel generators.

3. The AP1000 design philosophy for the MCR and TSC habitability is the same as for the AP600. Discussions of this design were provided in AP600 RAIs 100.10 and 100.33. In a very limited number of instances, the TSC may become uninhabitable. As stated in the [DCD Tier 2, Section] 18.8.3.5, even in the low probability case of a station blackout, the TSC will still most likely remain habitable. The doors to the TSC can be opened to aid with ventilation and control of room temperature for the two hours that the workstations continue to operate. The TSC workstations are powered from the non-Class 1E uninterruptable [sic] power supplies, therefore plant monitoring capability from the TSC exists for two hours following a station blackout. (The probability of a station blackout is discussed in the AP1000 Probability Risk Assessment. The probability of a station blackout occurring is 8.57×10^{-4}. The probability of

non-recovery within 2 hours is specified in the EPRI ALWR Utility Document as 0.37.)

To ensure that the functions of the TSC are not impeded, Westinghouse states in DCD [Tier 2, Section] 13.3 that staffing of the EOF for the AP1000 will occur consistent with current operating practice and revision 1 of NUREG-0654/FEMA-REP-1. In the unlikely event of a loss of offsite power and loss of all onsite AC power, the Combined License applicant shall immediately activate the EOF rather [than] bringing it to standby status. As stated in DCD [Tier 2, Section] 18.8.3.5 a communicator is assigned to the MCR as part of the emergency staff. The communicator is responsible for providing direct interface between the TSC and the MCR operators. If the TSC function has been transfered to the EOF, then the communicator provides the direct interface between the EOF and the MCR operators. The Combined License applicant is responsible for the EOF design, including the specification of its location(s) (DCD [Tier 2, Section] 18.2.6), emergency planning, and associated communication interfaces among the MCR, the TSC, and the EOF (DCD [Tier 2, Section] 13.3). Westinghouse has committed to providing a TSC communicator in the MCR for the unlikely event that the TSC becomes uninhabitable. When the Combined license applicant establishes the emergency plan and associated communication interfaces among the MCR, the TSC, and the EOF; the NRC will have an opportunity to review that plan, including the total number of TSC support personnel that will be sent to the MCR in the event that the TSC becomes uninhabitable as well as the location of the EOF.

13.3.3.3.3 TSC as a Vital Area

According to Section 2.6 of NUREG-0696, the purpose of the TSC is to provide direct management and technical support to the control room during an accident. Section II.B.2 of NUREG-0737 states that any area which will, or may, require occupancy to permit an operator to aid in the mitigation of, or recovery from, an accident is designated as a "vital area," and the control room and TSC must be included among those areas to which access is considered vital after an accident. Further, the design dose rate for personnel in a vital area should be such that doses do not exceed the guidelines of GDC 19 during an accident. GDC 19 requires that radiation protection be adequate to ensure that the dose to personnel does not exceed 0.05 Sv (5 rem) whole body, or its equivalent to any part of the body, for the duration of the accident. In addition, Subsection 8.2.1.f of Supplement 1 to NUREG-0737 states that the TSC will be provided with radiological protection and monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 0.05 Sv (5 rem) whole body, or its equivalent to any part of the body, for the duration of the accident. These guidelines form the basic radiological habitability criteria for the TSC.

Section H.1 of NUREG-0654/FEMA-REP-1, Revision 1, calls for establishment of a TSC in accordance with NUREG-0696. Section 2.6 of NUREG-0696 states that because the TSC is to provide direct management and technical support to the control room during an accident, it shall have the same radiological habitability as the control room under accident conditions. In addition, the TSC ventilation system shall function in a manner comparable to the control room ventilation system. If the TSC becomes uninhabitable, the TSC plant management function shall be transferred to the control room.

As discussed above, the applicant stated in a previous version of DCD Tier 2, Section 18.8.3.5, that the TSC has no emergency habitability requirements and that this is consistent with NUREG-0737. However, Section II.B.2 of NUREG-0737 designates the TSC as a vital area governed by the related radiation protection criteria of GDC 19 during an accident. Thus, the statement that the TSC "has no emergency habitability requirements" is not consistent with NUREG-0737. In its additional response to RAI 472.003, the applicant acknowledged the apparent inconsistency was "confusing" and the statement was removed from DCD Tier 2, Section 18.8.3.5. In addition, the applicant further stated that "[i]n practical terms, the TSC does have emergency habitability capabilities comparable to those of operating plants as long as electrical power is available either from offsite power or from the onsite diesel generators."

In the AP1000 DSER, the staff stated that despite the removal of the statement that the TSC has no emergency habitability requirements from DCD Tier 2, Section 18.8.3.5, the design of the ventilation systems for the TSC and MCR did not provide the TSC with the same radiological habitability as the MCR under all accident conditions. The staff further stated in the DSER that the AP1000 TSC emergency habitability capabilities did not comport with the TSC emergency habitability criteria of NUREG-0696, NUREG-0737, and Supplement 1 to NUREG-0737. As such, the staff identified the inability of the TSC to provide emergency habitability under accident conditions as Open Item 13.3-1.a in the DSER.

In response to DSER Open Item 13.3-1.a, the applicant stated in its July 7, 2003, letter the following:

> The TSC is designed to meet GDC 19 limits during accident conditions. This is consistent with the guidance of NUREG-0696, section 2.6, Habitability, and NUREG-0737. The DCD states that the VBS meets GDC 19 under the "Abnormal Plant Operation" heading of DCD [Tier 2, Section] 9.4.1.2.3.1. "The main control room/technical support center HVAC equipment and ductwork that form an extension of the main control room/technical support center pressure boundary limit the overall infiltration (negative operating pressure) and exfiltration (positive operating pressure) rates to those values shown in [DCD Tier 2,] Table 9.4.1-1. Based on these values, the system is designed to maintain operator doses within allowable General Design Criteria (GDC) 19 limits."
>
> The AP1000 ventilation system serving the TSC exceeds the guidance of NUREG-0696 as it is redundant, instrumented in the control room and is automatically activated. NUREG-0696, Section 2.6 states, "The TSC ventilation system need not be seismic Category I qualified, redundant, instrumented in the control room, or automatically activated to fulfill its role."
>
> NUREG-0696 guidance does not suggest that the TSC meet habitability requirements all of the time. Section 2.6 of the NUREG states, "If the TSC becomes uninhabitable, the TSC plant management function shall be transferred to the control room." The existence of this statement is acknowledgment that there may be times when the TSC

habitability could be challenged. This acknowledgment [sic] is logical given the fact that the ventilation system redundancy and qualification guidance of NUREG-0696 are less stringent than those for the control room ventilation system.

Based on the above, Westinghouse believes that AP1000 meets the NUREG-0696, section 2.6 guidance to "... have the same radiological habitability as the control room under accident conditions." Westinghouse also believes that it has met all applicable requirements and guidance associated with providing TSC habitability.

The staff discussed Open Item 13.3-1.a with the applicant during a public meeting on July 10, 2003. In regard to the issue of whether the TSC, as a vital area, must have the same radiological habitability as the MCR under all accident conditions, it was determined that the applicable plant conditions for which GDC 19 limits apply are the AP1000 defined, Condition IV "limiting faults" (or DBAs). In DCD Tier 2, Section 15.0.1, "Classification of Plant Conditions," the applicant states the following, in part:

The ANSI 18.2 (Reference 1[1]) classification divides plant conditions into four categories according to anticipated frequency of occurrence and potential radiological consequences to the public. The four categories are as follows:

- Condition I: Normal operation and operational transients
- Condition II: Faults of moderate frequency
- Condition III: Infrequent faults
- *Condition IV: Limiting faults*

The basic principle applied in relating design requirements to each of the conditions is that the most probable occurrences should yield the least radiological risk, and those extreme situations having the potential for the greatest risk should be those least likely to occur.

The eight Condition IV limiting faults (DBAs) are listed in DCD Tier 2, Section 15.0.1.4, "Condition IV: Limiting Faults," which states the following, in part:

Condition IV events are faults that are not expected to take place, but are postulated because their consequences include the potential of the release of significant amounts of radioactive material. They are the faults that must be designed against, and they represent limiting design cases. Condition IV faults are not to cause a fission product release to the environment resulting in doses in excess of the guideline values of 10 CFR Part 100. A single Condition IV event is not to cause a consequential loss of required functions of systems needed to cope with the fault, including those of the emergency core cooling system and the containment. The following faults are classified in this category:

---

[1]American National Standards Institute N18.2, "Nuclear Safety Criteria for the Design of Stationary PWR Plants," 1973.

- Steam system piping failure (major)
- Feedwater system pipe break
- Reactor coolant pump shaft seizure (locked rotor)
- Reactor coolant pump shaft break
- Spectrum of RCCA ejection accidents
- Steam generator tube rupture
- LOCAs resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary (large break)
- Design basis fuel handling accidents

The applicant's reference to DCD Tier 2, Section 9.4.1.2.3.1, and specifically to the discussion under the subsection entitled "Abnormal Plant Operation," is relevant, in that the eight DBAs constitute the limiting design accidents (or faults) that are considered for purposes of ensuring TSC habitability (i.e., meeting GDC 19 limits) rather than for all accident conditions. Specifically, the design of the MCR/TSC HVAC equipment and ductwork is such that the doses in the TSC would be maintained within allowable GDC 19 limits, assuming the continued operation of the nuclear island nonradioactive ventilation system (VBS). The MCR emergency habitability system (VES) is considered the design-basis emergency ventilation system for the MCR, and is not designed to be the emergency ventilation system for the TSC.

The staff stated in a conference call with the applicant on July 29, 2003, that the applicant should explicitly state in the DCD that when VBS is operating it is designed to maintain the TSC within allowable GDC 19 limits for the DBAs. This was reflected in applicant's July 31, 2003, letter, in which applicant provided the following additional response to DSER Open Item 13.3-1a, regarding TSC habitability:

> Westinghouse will revise DCD [Tier 2, Section] 9.4.1.2.3.1 as identified in the "Design Control Document (DCD) Revision:" portion of this response to address the NRC comment. DCD [Tier 2, Section] 9.4.1.2.3.1 has also been revised to clarify that in the event of a loss of the plant ac electrical system, the VBS supplemental air filtration system can be manually transferred to the onsite standby diesel generators.

The staff reviewed DCD Tier 2, Section 9.4.1.2.3.1 and noted that it has been revised to include the following under Abnormal Plant Operation:

> ...The main control room/technical support center HVAC equipment and ductwork that form an extension of the main control room/technical support center pressure boundary limit the overall infiltration (negative operating pressure) and exfiltration (positive operating pressure) rates to those values shown in [DCD Tier 2,] Table 9.4.1-1. Based on these values, the system is designed to maintain personnel doses within allowable

> General Design Criteria (GDC) 19 limits during design basis accidents in both the main control room and the technical support center.
>
> If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding GDC 19 operator dose limits, the protection and safety monitoring system automatically isolates the MCR from the normal main control room/technical support center HVAC subsystem by closing the supply, return, and toilet exhaust isolation valves. Main control room habitability is maintained by the main control room emergency habitability system, which is discussed in [DCD Tier 2,] Section 6.4.

The staff finds this to be acceptable. Therefore, Open Item 13.3-1.a is resolved.

13.3.3.3.4 Isolation of MCR from TSC

In DCD Tier 2, Section 18.8.3.5, the applicant states that "[t]he TSC complies with the habitability requirements of Reference 27 [i.e., Supplement 1 to NUREG-0737] when electrical power is available." The reference to "when electrical power is available" is but one, of two, triggering events that would automatically isolate the MCR from the TSC. The second triggering event is "high-high particulate or iodine radioactivity in MCR air supply duct" (see DCD Tier 2, Section 6.4.4, "System Safety Evaluation"). The second triggering event was not reflected in a previous version of DCD Tier 2, Section 3.1.2, "Protection by Multiple Fission Product Barriers," which stated under Criterion 19, "Control Room," that "[i]f the normal main control room ventilation system is inoperable or if no ac power sources are available, the emergency control room habitability system automatically isolates the main control room and provides operator habitability requirements." If, for example, electrical power was available, while at the same time high-high particulate or iodine radioactivity was in the MCR air supply, the MCR would automatically isolate from the TSC. As such, the TSC would no longer be able to ensure compliance with the radiological protection requirements of GDC 19 and, therefore, the TSC would be unable to comply with the radiological habitability criteria of Supplement 1 to NUREG-0737 (i.e., Reference 27). Hence, the statement that the TSC complies with the habitability requirements of Supplement 1 to NUREG-0737 when electrical power is available was considered incomplete.

Addressing this concern, the applicant stated the following in its additional response to RAI 472.003:

> Should a "high-high" radiation signal or if a station blackout of more than 10 minutes occur, the VBS stops, isolates the MCR envelop and the VES begins operation to protect the MCR operators. If the system has power and is operating, it will prevent a "high-high" radiation signal. This is the reason DCD [Tier 2, Section] 18.8.3.5 states, "The TSC complies with the habitability requirements of Reference 27 [i.e., Supplement 1 to NUREG-0737] when electrical power is available."

This response was somewhat confusing. Either a high-high radiation signal or loss of power can trigger the isolation of the MCR envelop. This means that isolation can only occur on a high-high radiation signal, even without loss of power. The statement that "[i]f the system has power and is operating, it will prevent a 'high-high' radiation signal" implies that a high-high radiation signal will never occur, except upon loss of power. The high-high radiation signal as a trigger to automatically isolate the MCR is, therefore, not needed, since the isolation already occurs upon loss of power. Subsequent high-high radioactivity would be inconsequential because the MCR would have already been isolated from the TSC upon loss of power, with potential loss of TSC habitability. The staff requested that the applicant resolve these habitability concerns. This was Open Item 13.3-1.b in the DSER.

In response to DSER Open Item 13.3-1.b, the applicant stated in its July 7, 2003, letter the following.

> As stated in the response to DSER Open Item 13.3-1.a., Westinghouse believes that AP1000 meets all applicable requirements and guidance associated with providing TSC habitability. As for VBS operation, Westinghouse provides the following discussion, which hopefully will clarify how the system, including isolation signals, is intended to function.
>
> The only events that would shutdown VBS would be a loss of power or multiple failures to the redundant systems. These events are no different than the events that would cause the HVAC systems serving the TSC in a conventional plant to shutdown. A "high-high" radiation signal would not occur if VBS is operating properly. If VBS is operating properly, it is filtering the air, as well as providing a positive pressure in both the MCR and the TSC which precludes a "high-high" signal from being generated. In the case where there is a loss of power, VBS would isolate the MCR after a period of 10 minutes. The 10 minute delay allows for the high probability that the on-site standby diesel generators will start, thereby restoring power to the plant and to VBS. The delay also minimizes isolating the control room and actuating VES when it is not necessary. Should there be a coincident high radiation event during the loss of power event however, VBS would not delay 10 minutes, but would instead immediately isolate the main control room. Therefore, the only time that the "high-high" isolation is "needed" is in the 10 minute period following a loss of power to the VBS. It is however good engineering practice to provide diverse parameters to actuate safety systems. Thus, the statements in the DCD, which identify that isolation of the MCR envelope can occur with either a "high-high" radiation signal or loss of power and; that the TSC complies with the habitability requirements of Supplement 1 to NUREG-0737 when electrical power is available are correct and consistent with the design.
>
> Westinghouse is not proposing specific word changes to the DCD at this time to address VBS operation. However, we are amenable to such word changes if it helps to resolve this issue.

In applicant's July 7, 2003, letter (above) they stated that "[s]hould there be a coincident high radiation event during the loss of power event however, VBS would not delay 10 minutes, but would instead immediately isolate the main control room." The staff indicated in the July 29, 2003, telephone conference with applicant that this statement seemed to indicate that there was an additional (i.e., third), previously unidentified, triggering event (for MCR isolation/VES actuation). The applicant clarified at that time that the "high radiation event" meant a coincident "high-high" radioactivity signal; and not the "high" gaseous radioactivity detected signal in the MCR supply air duct (as described in DCD Tier 2, Section 9.4.1.2.3.1, under "Abnormal Plant Operation"), which would automatically start the pressurization of the MCR and TSC. This was reflected in applicant's July 31, 2003, letter where applicant stated the following.

> Westinghouse will [revise] the DCD as identified in the "Design Control Document (DCD) Revision:" portion of this response to improve the consistency of the description of the VES triggering events. Please note that there is no "third" triggering event leading to the actuation of VES. The "high radiation event" referred to in our earlier response to the DSER open item and contained in the phrase "<u>a coincident high radiation event during the loss of power event</u>" is not meant to describe actuation logic, but rather a generic condition in which high radiation exists.

The applicant committed to the following DCD Revisions:

DCD Tier 2, Section 1.9.4.2.3, "New Generic Issues," Issue 83 - Control Room Habitability; revise the 1st and 2nd paragraphs under AP1000 Response as follows:

> Habitability of the main control room is provided by the main control room/technical support center HVAC subsystem of the nonsafety-related nuclear island nonradioactive ventilation system (VBS). If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The safety-related main control room emergency habitability system supplies breathable quality air for the main control room operators while the main control room is isolated.
>
> In the event of external smoke or radiation release, the nonsafety-related nuclear island nonradioactive ventilation system provides for a supplemental filtration mode of operation, as discussed in [DCD Tier 2,] Section 9.4. In the unlikely event of a toxic chemical release, the safety-related main control room emergency habitability system has the capability to be manually actuated by the operators. Further, a 6-hour supply of self-contained portable breathing equipment is stored inside the main control room pressure boundary.

DCD Tier 2, Section 3.1.2, "Protection by Multiple Fission Product Barriers," Criterion 19 - Control Room; revise the 3rd and 4th paragraphs under AP1000 Compliance as follows:

> The main control room is shielded by the containment and auxiliary building from direct gamma radiation and inhalation doses resulting from the postulated release of fission products inside containment. Refer to Chapter 15 for additional information on accident conditions. The main control room/technical support center HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS) allows access to and occupancy of the main control room under accident conditions as described in [DCD Tier 2,

Section] 9.4.1. Sufficient shielding and the main control room/technical support center HVAC subsystem provide adequate protection so that personnel will not receive radiation exposure in excess of 5 rem whole-body or its equivalent to any part of the body for the duration of the accident.

If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The main control room emergency habitability system also allows access to and occupancy of the main control room under accident conditions. The emergency main control room habitability system is designed to satisfy seismic Category I requirements as described in [DCD Tier 2,] Section 3.2; the system design is described in [DCD Tier 2,] Section 6.4.

DCD Tier 2, Section 6.4, "Habitability Systems"; revise the 3rd paragraph as follows:

If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The main control room emergency habitability system is capable of providing emergency ventilation and pressurization for the main control room.

DCD Tier 2, Section 6.4.3.2, "Emergency Mode"; revise the 1st paragraph as follows:

Operation of the main control room emergency habitability system is automatically initiated by either of the following conditions:

- "High-high" particulate or iodine radioactivity in the main control room supply air duct

- Loss of ac power for more than 10 minutes

DCD Tier 2, Section 6.4.4 "System Safety Evaluation"; revise the 3rd from last paragraph as follows:

Automatic transfer of habitability system functions from the main control room/technical support center HVAC subsystem of the nuclear island nonradioactive ventilation system to the main control room emergency habitability system is initiated by either of the following conditions:

- "High-high" particulate or iodine radioactivity in MCR air supply duct
- Loss of ac power for more than 10 minutes

DCD Tier 2, Section 9.4.1.2.3.1, "Main Control Room/Technical Support Center HVAC Subsystem"; revise the last sentence of the 2nd paragraph under Abnormal Plant Operation as follows: (Note: The second to last sentence is also shown below. It has no changes but is included for contextual purposes only.)

> The main control room/technical support center HVAC equipment and ductwork that form an extension of the main control room/technical support center pressure boundary limit the overall infiltration (negative operating pressure) and exfiltration (positive operating pressure) rates to those value shown in [DCD Tier 2,] Table 9.4.1-1. Based on these values, the system is designed to maintain personnel doses within allowable [GDC] 19 limits during design basis accidents in both the main control room and the technical support center.

DCD Tier 2, Section 9.4.1.2.3.1; revise the last sentence of the 3rd paragraph under Abnormal Plant Operation as follows:

> If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding GDC 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room from the normal main control room/technical support center HVAC subsystem by closing the supply, return, and toilet exhaust isolation valves. Main control room habitability is maintained by the main control room emergency habitability system, which is discussed in [DCD Tier 2,] Section 6.4.

DCD Tier 2, Section 9.4.1.2.3.1; revise the last sentence of the 3rd to last paragraph under Abnormal Plant Operation as follows:

> Power is supplied to the main control room/technical support center HVAC subsystem by the plant ac electrical system. In the event of a loss of the plant ac electrical system, the main control room/technical support center ventilation subsystem can be transferred to the onsite standby diesel generators.

DCD Tier 1, Section 2.7.1, "Nuclear Island Nonradioactive Ventilation System"; revise the last sentence of 1st paragraph under Design Description as follows:

> In addition, the VBS isolates the HVAC penetrations in the main control room boundary on "high-high" particulate or iodine radioactivity in the main control room supply air duct or on a loss of ac power for more than 10 minutes. This action supports operation of the main control room emergency habitability system (VES).

The above proposed revisions clarify the details associated with the VES triggering events and provide for consistency of the descriptions throughout the document. The staff has verified that these revisions have been incorporated in the DCD. As such, the staff finds this to be acceptable. Therefore, Open Item 13.3-1.b is resolved.

13.3.3.3.5 TSC Evacuation

Because of the unique design of the AP1000, the habitability system for the TSC is not the same as for the MCR under all conditions. At currently operating reactors, the TSC habitability system is either the same as for the control room, or the TSC has been provided a separate habitability system. At these sites, should the TSC become uninhabitable, occupants are usually evacuated to either the control room or another location onsite where habitability can be established. Not having the TSC in the same habitability envelope as the MCR, as discussed above, increases the likelihood that the TSC will have to be evacuated due to either loss of ac power sources, or high-high particulate or iodine radioactivity in the MCR air supply.

In DCD Tier 2, Section 18.8.3.5 the applicant had stated that should TSC habitability be challenged, TSC personnel and functions would be transferred to the EOF where habitability is not dependent on plant systems, and with communication and data transfer links to the MCR to provide essential exchange of information. Consequently, the EOF would have to be activated and staffed early, in order to ensure that the functions and support provided to the MCR by the TSC are not impeded. This proposed arrangement was reflected in an earlier version of DCD Tier 2, Section 13.3.1 with the following COL information item (i.e., COL action item).

> Combined License applicants referencing the AP1000 certified design will address the activation of the emergency operations facility consistent with current operating practice and NUREG-0654/FEMA-REP-1 except for a loss of offsite power <u>and</u> loss of all onsite AC power. For this initiating condition, the Combined License applicant shall immediately activate the emergency operations facility rather than bringing it to a standby status.

In regard to TSC communications, DCD Tier 2, Section 1.8, "Interfaces for Standard Design," states that communications systems and equipment outside the annex building (which includes the TSC) are site-specific elements and are outside the scope of the AP1000 standard plant, and that the DCD is based upon the COL applicant providing adequate external communications.

The staff does not agree with this approach because the physical location of the EOF was not addressed, as it related to the EOF serving as an alternate TSC. In addition, the distinction between transferring the TSC plant management function to the EOF upon loss of TSC habitability, rather than to the MCR (per Section 2.6 of NUREG-0696), was not discussed.

In the applicant's additional response to RAI 472.003 (Revision 1), the use of EOF as an alternate TSC was justified by the capabilities of the EOF, as well as when it would be activated. In addition, the applicant stated that the EOF design, including location, EP and communications is the COL applicant's responsibility. Staff responded in the DSER, saying that the TSC design requirements could not be ignored based on unknown compensatory measures, and that if the EOF is the alternate TSC, its location would need to be evaluated against the following guidance criteria from Section 2.2 of NUREG-0696.

> The onsite TSC is to provide facilities near the control room for detailed analyses of plant conditions during abnormal conditions or emergencies by trained and competent

> technical staff. During recent events at nuclear power plants, telephone communications between the facilities were ineffective in providing all of the necessary management interaction and technical information exchange. This demonstrates the need for face-to-face communications between TSC and control room personnel. To accomplish this, the TSC shall be as close as possible to the control room, preferably located within the same building. The walking time from the TSC to the control room shall not exceed 2 minutes. This close location will facilitate face-to-face interaction between control room personnel and the senior plant manager working in the TSC. This proximity also will provide access to information in the control room that is not available in the TSC data system.

Resolution of the above discussion, pertaining to the TSC habitability and utilization of the EOF as an alternate TSC, was Open Item 13.3-2 in the DSER.

In its July 7, 2003, response to Open Item 13.3-2, the applicant stated the following:

> As stated in the response to DSER Open Item 13.3-1, Westinghouse believes that AP1000 meets all applicable requirements and guidance associated with providing TSC habitability. Upon re-reviewing the regulations and guidance associated with the transfer of TSC functions in the event that the TSC becomes uninhabitable, Westinghouse will revise the DCD to be consistent with the guidance of NUREG-0696, Section 2.6, "Habitability." In that case, the TSC plant management function will be transferred to the main control room. The EOF will not be used as an alternate TSC.
>
> Also, as the TSC personnel and functions are not going to be transferred to the EOF, the COL requirement to activate the EOF when both onsite and offsite ac power is lost will be removed from the DCD. The AP1000 DCD will be revised as shown below in the, "Design Control Document (DCD) Revision" section of this open item.

The last paragraph of DCD Tier 2, Section 13.3, was revised as follows:

> Staffing of the emergency operations facility occurs consistent with current operating practice and with revision 1 of NUREG-0654/FEMA-REP-1.

The 2nd paragraph of DCD Tier 2, Section 13.3.1, "Combined License Information Item," was revised as follows:

> Combined license applicants referencing the AP1000 certified design will address the activation of the emergency operations facility consistent with current operating practice and NUREG-0654/FEMA-REP-1.

This is COL Action Item 13.3.3.3.5-1.

Conduct of Operations

The 7th paragraph of DCD Tier 2, Section 18.8.3.5, was revised as follows:

> Should habitability be challenged within the TSC due to lack of cooling or a high radiation level resulting from a beyond-design-basis accident, the plant management function of the TSC is transferred to the main control room.

The 8th [9th] paragraph of DCD Teir 2, Section 18.8.3.5, was revised as follows:

> The combined license applicant is responsible for the EOF design, including the specification of its location ([DCD Tier 2, Section] 18.2.6) and emergency planning, and associated communication interfaces among the main control room, the TSC, and the EOF (Section 13.3).

Finally, the 11th (i.e. next to last) paragraph of DCD Tier 2, Sec 18.8.3.5 was deleted.

The above proposed revisions adequately address the possible evacuation of the TSC. In addition, the associated TSC habitability issue is adequately addressed above. The staff verified the changes had been incorporated into the DCD. As such, the staff finds this to be acceptable. Therefore, Open Item 13.3-2 is resolved.

13.3.3.3.6 Summary of TSC Habitability Issues

The staff concludes that the information provided in the DCD pertaining to habitability of the TSC is consistent with the guidance criteria identified in RG 1.101, which endorses Revision 1 of NUREG-0654/FEMA-REP-1, and through it NUREG-0696, NUREG-0737, and Supplement 1 to NUREG-0737. As such, the staff finds that this meets the applicable requirements of 10 CFR 50.34(f)(2)(xxv), 10 CFR 50.47(b)(8) and (b)(11), and Subsection IV.E.8 of Appendix E to 10 CFR Part 50.

13.3.3.4 <u>Postaccident Sampling and Analysis</u>

In accordance with 10 CFR 50.47(b)(9), the COL applicant must employ adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition. To address this regulation, the NRC has concluded that source term information should be obtained and analyzed promptly to continuously assess and refine dose assessments and confirm or modify initial protective action recommendations.

The requirements of 10 CFR 52.79(b) state that a COL application must contain the technically relevant information required of applicants for an operating license under 10 CFR 50.34. The requirements of 10 CFR 50.34(f)(2)(viii) state that the COL applicant must provide a capability to promptly obtain and analyze samples from the reactor coolant system and containment that may contain accident source term radioactive materials, without radiation exposures to any individual exceeding 0.05 Sv (5 rem) to the whole body or 0.5 Sv (50 rem) to the extremities. Materials to be analyzed and quantified include certain radionuclides that are indicators of the degree of core damage (e.g., noble gases, radioiodines and cesiums, and nonvolatile isotopes), hydrogen in the containment atmosphere, dissolved gases, chloride, and boron concentrations.

13.3.3.4.1 Model Safety Evaluation

On October 31, 2000, the NRC published a Federal Register notice (65 FR 65018), entitled "Notice of Availability for Referencing in License Amendment Applications—Model Safety Evaluation on Technical Specification Improvement to Eliminate Requirements on Post Accident Sampling Systems Using the Consolidated Line Item Improvement Process." The model safety evaluation states that the information provided by the PASS, described in NUREG-0737, "Clarification of TMI Action Plan Requirements," is either unnecessary or is effectively provided by other indicators of process parameters or measurement of radiation levels. Sampling of various radionuclides is not required to support emergency response decisionmaking during the initial phases of an accident because the information provided by PASS is either unnecessary or is effectively provided by other indications of process parameters or measurement of radiation levels. Therefore, it is not necessary to have dedicated equipment to promptly obtain the various samples identified in the model safety evaluation.

However, information about the radionuclides existing postaccident could be of significant benefit in addressing public concerns and planning for long-term recovery operations. In addition, radionuclide sampling information could also be useful in classifying certain types of events that could cause fuel damage without having an indication of overheating on core exit thermocouples. Licensees could satisfy this function by developing contingency plans to describe existing sampling capabilities and what action (e.g., assembling temporary shielding) may be necessary to obtain and analyze highly radioactive samples from the reactor coolant system, containment sump, and containment atmosphere. These contingency plans must be available for use by a licensee during an accident. Finally, the model safety evaluation states that each licensee should verify that it has, and will make a regulatory commitment to maintain (or make a regulatory commitment to develop and maintain), contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere.

DCD Tier 2, Section 1.9.5.2.9, "Post-Accident Sampling System," states that the PASS is a subsystem of the primary sampling system and that the primary sampling system is designed to conform to the guidelines of the model safety evaluation report on eliminating PASS requirements from technical specifications for operating plants. DCD Tier 2, Section 1.9.3, "Three Mile Island Issues," under (2)(viii), "Post-Accident Sampling (NUREG-0737 Item II.B.3)," states that the AP1000 sampling design is consistent with the approach in the model safety evaluation report and not the guidance outlined in NUREG-0737 and RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident" (Revision 3, May 1983). The primary sampling system design is consistent with contingency plans to obtain and analyze highly radioactive postaccident samples from the reactor coolant system, the containment sump, and the containment atmosphere.

DCD Tier 2, Section 9.3.3.1.2.2, "Post-Accident Sampling," states that the primary sampling system does not include specific postaccident sampling capability. However, there are contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere. These plans include the procedures to analyze, during the later stages of accident response, reactor coolant for boron, containment atmosphere for hydrogen and fission products, and containment sump water for pH. The primary means of containment atmosphere hydrogen analysis is the hydrogen analyzer, which is not part of the postaccident sampling capabilities.

An earlier version of DCD Tier 2, Section 13.3.1, had provided the following COL information item (i.e., COL action item):

> To initially and continuously assess the course of an accident for emergency response purposes, Combined License applicants referencing the AP1000 certified design will address the capability for promptly obtaining and analyzing grab samples of reactor coolant and containment atmosphere and sump in accordance with the guidance of Item II.B.3 of NUREG-0737.

This COL information item, which was removed from subsequent AP1000 DCD Tier 2, Section 13.3.1 revisions, was the same as that which was provided in Section 13.3 of the standard safety analysis report (SSAR) for the Westinghouse AP600 standard design and appears as COL Action Item 13.3-3 in the NRC's AP600 FSER in September 1998. Appendix C to 10 CFR Part 52, entitled "Design Certification Rule for the AP600 Design," was published in the Federal Register on December 23, 1999 (64 FR 72002, 72015). The NRC staff issued the FSER related to certification of the AP600 standard plant design in September 1998 (NUREG-1512, 63 FR 48772). At that time, the PASS guidance in NUREG-0737 (Section II.B.3) was applicable. As discussed above, the model safety evaluation published on October 31, 2000, eliminated various emergency response PASS sampling requirements in Section II.B.3 of NUREG-0737. As such, this COL action item in DCD Section 13.3.1 did not reflect the model safety evaluation, and was inconsistent with the other DCD sections that refer to the model safety evaluation and its acceptance of the use of contingency plans.

13.3.3.4.2 Radiation Exposure

DCD Tier 2, Section 9.3.3, "Primary Sampling System," states that the primary sampling system includes equipment to collect representative samples of the various process fluids, including reactor coolant system and containment air, in a manner that adheres to as low as is reasonably achievable (ALARA) principles during normal and post-accident conditions. In addition, DCD Tier 2, Section 12.4.1.8, "Post-Accident Actions," states the following:

> Requirements of 10 CFR 52.79(b) relative to plant area access and post-accident sampling (10 CFR 50.34(f)(2)(viii)[)] are included in [DCD Tier 2,] Section 1.9.3. If procedures are followed, the design prevents radiation exposures to any individual from exceeding 5 rem [0.05 Sv] to the whole body or 50 rem [0.5 Sv] to the extremities.

The staff concludes that the information provided in the AP1000 DCD pertaining to controlling radiation exposures to individuals involved in postaccident sampling is acceptable and meets the applicable requirements of 10 CFR 50.34(f)(2)(viii), 10 CFR 50.47(b)(8), 10 CFR 50.47(b)(9), and 10 CFR 50.47(b)(11).

13.3.4 Overall Emergency Planning Findings

The following sections summarize the EP findings.

13.3.4.1 Emergency Planning Responsibilities (see Section 13.3.2 of this report)

The staff concludes that the COL applicant referencing the AP1000 design will be the primary party addressing EP, and that EP information submitted in the application will largely depend on plant- and site-specific characteristics. As such, the staff finds that COL Action Item 13.3-1 is acceptable, in that it complies with the requirements set forth in 10 CFR 52.79(d) and the applicable portions of 10 CFR Part 50. It is consistent with the extent to which certain EP design features, facilities, functions, and equipment are more appropriately addressed by the COL applicant.

13.3.4.2 General Description of Facilities (see Section 13.3.3.1 of this report)

The staff concludes that the information provided in the DCD pertaining to the TSC, OSC, and decontamination room is consistent with the guidance identified in RG 1.101. As such, the staff finds this information meets the applicable requirements of 10 CFR 50.34(f)(2)(xxv), 10 CFR 50.47(b)(8), 10 CFR 50.47(b)(11), and Subsections IV.E.3 and IV.E.8 to 10 CFR Part 50, Appendix E.

13.3.4.3 Technical Support Center Size (see Section 13.3.3.2 of this report)

The staff concludes that the information provided in the DCD pertaining to TSC size is consistent with guidance identified in RG 1.101. Specifically, the size conforms with the specifications of NUREG-0696 and is sufficient to accommodate and support NRC and licensee predesignated personnel, equipment, and documentation, in conformance with Supplement 1 to NUREG-0737. As such, the staff finds that this information meets the applicable requirements of 10 CFR 50.47(b)(8) and Subsection IV.E.8 to 10 CFR Part 50, Appendix E.

13.3.4.4 Technical Support Center Habitability (see Section 13.3.3.3 of this report)

The staff concludes that the information provided in the DCD pertaining to habitability of the TSC is consistent with the guidance identified in RG 1.101. As such, the staff finds that the DCD meets the applicable requirements of 10 CFR 50.34(f)(2)(xxv), 10 CFR 50.47(b)(8) and (b)(11), and Subsection IV.E.8 to 10 CFR Part 50, Appendix E.

13.3.4.5 Postaccident Sampling and Analysis - Radiation Exposure (see Section 13.3.3.4.2 of this report)

The staff concludes that the information provided in the AP1000 DCD pertaining to controlling radiation exposures to individuals involved in postaccident sampling is acceptable and meets the applicable requirements of 10 CFR 50.34(f)(2)viii), 10 CFR 50.47(b)(8), 10 CFR 50.47(b)(9), and 10 CFR 50.47(b)(11).

13.4 Operational Review

In DCD Tier 2, Section 13.4, the applicant stated that the COL applicant is responsible for operational review. In DCD Tier 2, Section 13.4.1, the applicant included a statement that a COL applicant referencing the AP1000 certified design will address each operational review. The staff finds this to be acceptable. This is COL Action Item 13.4-1.

13.5 Plant Procedures

In DCD Tier 2, Section 13.5, the applicant stated that the COL applicant is responsible for plant procedures. The applicant referred to WCAP-14690, Revision 1, "Designer's Input to Procedure Development for the AP600," issued June 1997, which provides input to the COL applicant for developing plant procedures, including information on the development and design of the AP1000 emergency response guidelines and emergency operating procedures. In DCD Tier 2, Section 13.5.1, the applicant stated that a COL applicant referencing the AP1000 certified design will address plant procedures for the following areas:

- normal operation
- abnormal operation
- emergency operation
- refueling and outage planning
- alarm response
- maintenance, inspection, test, and surveillance
- administration
- operation of post-72-hour equipment

The staff finds this to be acceptable. This is COL Action Item 13.5-1.

13.6 Security

The staff evaluated the security features of the AP1000 design as described in (1) AP1000 Security Assessment, Revision 1, March 2004 (safeguards information) and (2) DCD Tier 2, Section 1.2, "General Plant Description." The application was reviewed against the following requirements:

- 10 CFR 73.34, "Contents of applications; technical information"

- 10 CFR 73.55, "Requirements for physical protection of licensed activities in nuclear power reactors against radiological sabotage"

- 10 CFR 70.51, "Material balance, inventory, and records requirements"

The staff had not completed its review of the applicant's security program when the DSER was issued. Specifically, the staff had not reviewed the AP1000 Security Assessment Revision 1, dated March 2004. Completion of the security review was identified as Open Item 13.6-1 in the DSER.

13.6.1 Preliminary Planning

DCD Tier 2, Section 13.6.13.1, "Security Plans, Organization, and Testing," states that the comprehensive security plan is the responsibility of the COL applicant. The staff finds this approach acceptable. Because the COL application must include a physical security plan, safeguards contingency plan, and guard training and qualification plan, a preliminary planning submission is not necessary for the design certification.

While not required for the AP1000 design certification process, the applicant recognized the new security requirements that the NRC imposed by order on operating power reactors and assessed the AP1000 design against these requirements. DCD Tier 2, Section 13.6.1, "Preliminary Planning," states the following:

> As a result of the events of September 11, 2001, the NRC issued orders to power reactor licensees titled 'Interim Compensatory Measures [ICM's] for High Threat Environment' ([DCD] Reference 4). On April 29, 2003, the NRC also issued a revised 'Design Basis Threat [DBT] for Radiological Sabotage for Operating Power Reactors' ([DCD] Reference 5). An assessment of the impact of [the orders and ICMs] is provided in the AP1000 Security Assessment ([DCD] Reference 6) that has been submitted under separate cover in accordance with 10 CFR 73.21. The AP1000 Security Assessment Document provides an assessment of how References 4 and 5 are addressed in the AP1000, and identifies the applicable requirements in References 4 and 5 that are addressed by the Combined License applicant for an AP1000.

The staff reviewed the information and positions taken in the noted AP1000 Security Assessment, and found this approach to be acceptable. Because the COL application must include physical security, safeguards contingency, and training and qualification plans, many of the security requirements in 10 CFR 73.55 are not required for the design certification.

13.6.2 Security Plan

DCD Tier 2, Section 13.6.2,"Security Plan," states the following:

> The comprehensive physical security program is the responsibility of the Combined License applicant and will be addressed in the security plan, contingency plan, and guard training plan provided by the Combined License applicant.

The staff finds this approach to be acceptable. The staff noted that a future COL applicant must address the physical security contingency and guard training and qualification plan in accordance with 10 CFR 50.34. This is COL Action Item 13.6.2-1.

Conduct of Operations

The COL applicant must provide site-specific physical security, contingency response, and guard training and qualification plans in accordance with 10 CFR 50.34 and 10 CFR 73.55. DCD Tier 2, Section 13.6.13.1, states the following:

> At least 60 days before loading fuel, the Combined License applicant will confirm that the security systems and programs described in its physical security plan, safeguards contingency plan, and training and qualification plan have achieved operational status and are available for the [NRC] staff's inspection. Operational status means that the security systems and programs are functioning. The determination that operational status has been achieved will be based on tests conducted under realistic operating conditions of sufficient duration to demonstrate that :
>
> - the equipment is operating;
> - procedures have been developed, approved, and implemented; and
> - personnel responsible for security operations and maintenance have been appropriately trained and have demonstrated their capability to perform their assigned duties and responsibilities.

The staff finds this approach to be acceptable. The COL applicant must (1) address the testing and maintenance in accordance with 10 CFR 73.55(g), (2) address general criteria for security personnel in accordance with 10 CFR Part 73, Appendix B, (3) develop security procedures in accordance with 10 CFR 73.55(b)(3) and (4) ensure only appropriately trained persons perform security job duties in accordance with 10 CFR 73.55(b)(4)(i). This is COL Action Item 13.6.2-2.

13.6.3 Plant Protection System

DCD Tier 2, Section, 13.6.3.1, "Introduction," states the following:

> A physical protection system and security organization is provided to protect the AP1000 from radiological sabotage, as required by 10 CFR 73.55. To achieve this objective, the physical protection system:
>
> - Includes a security organization
> - Locates vital equipment within vital areas
> - Controls points of personnel, vehicle, and material access into the vital areas,
> - Annunciates alarms in a continuously manned central alarm station and at least one other continuously manned alarmed station that is physically separated from the central alarm station
> - Provides for continuous communications between the security officers and the continuously manned alarmed stations

- Provides for testing and maintenance of the alarms, communications, and physical barriers

- Responds to threats of radiological sabotage in accordance with a developed contingency plan.

The staff finds this approach to be acceptable because a future COL applicant must address these requirements in its comprehensive security plan. All of these requirements are covered by other COL action items.

13.6.4 Physical Security Organization

DCD Tier 2, Section 13.6.4, "Physical Security Organization," states the following:

> The description of the site-specific physical security organization is the responsibility of the Combined License applicant. The size and capabilities of the physical security organization's armed response team are established by a vulnerability analysis and protective strategy development prepared by the Combined License applicant.

The staff finds this approach to be acceptable. The applicant for a combined license must address the physical security organization, as required by 10 CFR 73.55(b), in its comprehensive security plan, submitted in accordance with 10 CFR 50.34 and 10 CFR Part 73. This is COL Action Item 13.6.4-1.

13.6.5 Physical Barriers

13.6.5.1 Protected Area

DCD Tier 2, Section 13.6.5.1, "Protected Area," states the following:

> The definition of the protected area is the responsibility of the Combined License applicant.

The staff finds this approach to be acceptable. The COL applicant must define the parameters of the protected area and isolation zones as required by 10 CFR 73.55(c)(2) through (c)(3). This is COL Action Item 13.6.5.1-1.

13.6.5.2 Vital Areas

DCD Tier 2, Section 13.6.5.2, "Vital Areas," states the following:

> Vital equipment is located within designated vital areas. The AP1000's vital equipment is further encompassed by a shield building, a reinforced concrete and steel structure surrounding containment, and by portions of the reinforced concrete perimeter and interior wall of the auxiliary and annex buildings. Access points to the vital areas are locked and alarmed with active intrusion detection

> systems. The vital areas and a listing of the vital equipment are provided in [DCD] Reference 6.

The plant layout drawings in DCD Tier 2, Section 1.2, "General Plant Description," and the vital area designations on the layout drawings in the AP1000 Security Assessment, Revision 1, indicate proposed vital areas that include the MCR and the central alarm station. These drawings also designate the security power supply to be located within a vital area.

The staff finds that these measures satisfy the requirements of 10 CFR 73.55(c)(1), (e)(1) and (d)(7)(i)(D) and are acceptable.

13.6.5.3 <u>Bullet Resisting Barriers</u>

DCD Tier 2, Section 13.6.5.3, "Bullet Resisting Barriers," states the following:

> The doors, walls, floor, and ceiling of the main control room and the continuously manned alarm stations are designed to meet the bullet resisting criteria of UL 752, High Power Rifle Rating, including resistance to a level 4 round.

The layout drawings in DCD Tier 2, Figures 1.2-9 and 1.2-18 and Revision 1 to the AP1000 Security Assessment indicate that neither the MCR, central alarm station, nor the secondary alarm station contain windows. The staff finds that these measures satisfy the requirements of 10 CFR 73.55(c)(6) and (e)(1) and are acceptable.

DCD Tier 2, Section 13.6.5.3, further states:

> The Combined License applicant is responsible for the detail design and bullet resistance of the structure that isolates the individual responsible for the last access control function for admission to the protected area.

This is already covered by COL Action Item 13.6.13.2-1.

13.6.5.4 <u>Vehicle Barrier System</u>

DCD Tier 2, Section 13.6.5.4, "Vehicle Barrier System," states the following:

> The Combined License applicant is responsible for the definition, location, and the detailed design of the AP1000 Vehicle Barrier System.

The staff finds this approach to be acceptable. This is COL Action Item 13.6.5.4-1.

13.6.6 Access Requirements

DCD Tier 2, Section 13.6.6, "Access Requirements," states the following:

> Positive control features will be implemented to provide authorization for personnel and vehicles entering the vital areas. The Combined License applicant is responsible for the following access control features:
>
> - means for positive identification of authorized personnel entering the protected and vital areas
> - means for searching individuals, packages, and materials for firearms, explosives, and incendiary devices. This may be accomplished using detection devices such as metal detectors, explosive detectors, and x-ray machines.
>
> The AP1000 design certification scope includes:
>
> - access portals entering the vital areas are identified and unmanned portals are provided with alarm annunciation in the continuously manned alarm stations
> - vital area ingress and egress are designed to interface with other plant requirements and not impair plant operations during emergency conditions.

The staff finds this approach to be acceptable. The COL applicant must address the specific access control measures required by 10 CFR 73.55(d). This is COL Action Item 13.6.6-1.

13.6.7 Detection Aids

DCD Tier 2, Section 13.6.7, "Detection Aids," states the following:

> The design of the detection aids is the responsibility of the Combined License applicant.

The staff finds this approach to be acceptable. The COL applicant must ensure that all detection aids meet all the requirements within 10 CFR 73.55. This is COL Action Item 13.6.7-1.

13.6.8 Security Lighting

DCD Tier 2, Section 13.6.8, "Security Lighting," states the following:

> The AP1000 security lighting is the responsibility of the Combined License applicant.

The staff finds this approach to be acceptable. The COL applicant must ensure that the design of the security lighting meets the requirements of 10 CFR 73.55. This is COL Action Item 13.6.8-1.

13.6.9 Security Power Supply System

DCD Tier 2, Section 13.6.9, "Security Power Supply System," states the following:

> The security equipment that supports critical monitoring functions, such as intrusion detection, alarm assessment, and the security communications system, receives power from the security-dedicated uninterruptible power supply (UPS) system. Switchover to the uninterruptible power supply system is automatic and does not cause false alarms on annunciation modules. The uninterruptible power supply system is capable of sustaining operation for a minimum of 24 hours. The final design of the security power supply system is the responsibility of the Combined License applicant.

The staff finds this approach to be acceptable. The COL applicant must ensure that the final design of the security power supply system meets the requirements of 10 CFR 73.55(f)(4). This is COL Action Item 13.6.9-1.

13.6.10 Communications

DCD Tier 2, Section 13.6.10, "Communications," states the following:

> The final design of the security communications system will be addressed by the Combined License applicant. Two two-way communications paths are provided between the control room and the alarm stations within the AP1000. A single act of sabotage cannot sever both communications paths. Security force members with responsibilities to respond to acts of sabotage have the capability for continuous two-way communications with the alarm stations and with each other. The centralized communications equipment and radio antennas are located in a controlled area so that they will remain operable during a radiological sabotage event. Non-portable security communications equipment can be powered from the security power supply system so that it remains operable in the event of the loss of normal power.

The staff finds this approach to be acceptable. The COL applicant must ensure that the final design of the security communications system meets the requirements of 10 CFR 73.55(f). This is COL Action Item 13.6.10-1.

13.6.11 Testing and Maintenance

DCD Tier 2, Section 13.6.11, "Testing and Maintenance," states the following:

> The Combined License applicant must address testing and maintenance aspects of the plant security system.

The staff finds this approach to be acceptable. The COL applicant must ensure that testing and maintenance aspects of the plant security system meet the requirements of 10 CFR 73.55(g). This is COL Action Item 13.6.11-1.

13.6.12 Response Requirements

DCD Tier 2, Section 13.6.12, "Response Requirements," states the following:

> The Combined License applicant must address response requirements of the plant security system.

The staff finds this approach to be acceptable. The COL applicant must ensure that response requirements of the plant security system meet the requirements of 10 CFR 73.55(h). This is COL Action Item 13.6.12-1.

13.6.13 Combined License Information Items

13.6.13.1 Vital Equipment

DCD Section 13.6.13.2, "Vital Equipment" states the following:

> Combined License applicants referencing the AP1000 certified design will verify that the as-built location of vital equipment is inside the vital areas identified in Reference 6 [AP1000 Security Assessment].

The AP1000 Security Assessment, dated March 2004, indicates that the location of vital areas is within the DCD scope. The staff verified that the DCD locates the vital equipment within vital areas.

The staff finds the approach provided in the DCD to be acceptable. As required by 10 CFR 73.55(c)(1), vital equipment must be located only in a vital area located within a protected area, necessitating passage through two physical barriers for access. This is COL Action Item 13.6.13.1-1.

13.6.13.2 Plant Security System

DCD Tier 2, Section 13.6.13.3 states the following:

> Combined License applicants referencing the AP1000 certified design will address site-specific information related to the design, maintenance, and testing of the plant security system, including definition of the protected area; definition of control points for personnel, vehicle, and material access into the protected areas; detail design and bullet resistance of the structure that isolates the individual responsible for the last access control function for admission into the protected area; detection and alarm design features; security lighting; security

> power supply including the interfaces to the UPS system; and communication system.

The staff finds this approach to be acceptable. The COL applicant must describe the design features mentioned above in its COL application in sufficient detail for the staff to review their acceptability in light of the applicable requirements of 10 CFR 73.55. This is COL Action Item 13.6.13.2-1.

13.6.13.3 <u>Material Control</u>

A Westinghouse letter dated February 4, 2004, titled "Transmittal of Revised Responses to AP1000 DSER Open Items," addressed material controls. The letter stated, "Combined License applicants referencing the AP1000 certified design must address specific material control measures as required by 10 CFR Part 70 and the guidance provided in Reference 7." Reference 7 is American National Standards Institute (ANSI) N15.8, "Nuclear Material Control Systems for Nuclear Power Plants," issued 1974.

The staff finds this approach to be acceptable. The COL applicant must address specific material control measures as described in 10 CFR 70.51(c). These measures must satisfy the guidance of ANSI N15.8-1974. This is COL Action Item 13.6.13.3-1.

13.6.14 Other Security Issues

DCD Tier 2, Section 1.9.1.3, "Division 5 Regulatory Guides - Materials and Plant Protection," states the following:

> Regulatory Guide 5.12, "General use of Locks in the Protection and Control of Facilities and Special Nuclear Materials," provides guidelines for the selection and use of commercially available locks in the protection and facilities and special nuclear material. The guidance of this RG is considered appropriate for the AP1000 design.

DCD Tier 1, Section 3.3, Item 18, states "[t]he locks utilized for the protection of vital areas are manipulative resistant." Manipulation resistant is a key term to describe the type of locks specified as acceptable for use within the RG 5.12. The staff finds this measure satisfies the general requirement of 10 CFR 73.55(a) and is acceptable.

13.6.15 Conclusions

The staff concluded that there were no design features described in DCD Tier 2, Section 13.6, "Security," which would prevent the establishment and maintenance of an onsite physical protection system and security organization that would have as its objective to provide high assurance that activities involving special nuclear material are not inimical to the common defense and security and do not constitute an unreasonable risk to public health and safety, as required by 10 CFR 73.55. Therefore, Open Item 13.6-1 is resolved.

14. VERIFICATION PROGRAMS

14.1 Preliminary Safety Analysis Report Information

Regulatory Guide (RG) 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 3, Section 14.1, "Specific Information to Be Included in Preliminary Safety Analysis Reports," states that the applicant should provide information related to unique plant design features, compliance with test program RGs, utilization of operating and testing experience, test program schedule, and descriptions of organizations involved in testing and staffing. The applicant stated in Design Control Document (DCD) Tier 2, Section 14.1, "Specific Information to Be Included in Preliminary/Final Safety Analysis Reports," that this section is "not applicable to the AP1000 design." The U.S. Nuclear Regulatory Commission (NRC) staff determined that the applicant provided the technically relevant information specified in RG 1.70, Section 14.1, applicable to a design certification applicant under Title 10 of the Code of Federal Regulations (10 CFR) Part 52. DCD Tier 2, Section 14.2, "Specific Information to Be Included in Standard Safety Analysis Reports," includes test plans for unique plant design features, methods to satisfy appropriate RGs, and test program administration. On this basis, the NRC staff accepts the applicant's conclusion that the information to be included in Section 14.1 of a safety analysis report, as identified in RG 1.70, Revision 3, does not apply to the AP1000 design certification application.

14.2 Initial Plant Test Program

14.2.1 Introduction

The staff reviewed the applicant's initial test program in accordance with the review guidance contained in Section 14.2, "Initial Plant Test Program—Final Safety Analysis Report," of Revision 2 of the Standard Review Plan (SRP). The following sections document the results of the staff's review.

14.2.1.1 General

The requirements of 10 CFR 52.47(a)(i) specify, in part, that an applicant for design certification submit the technical information required of applicants for operating licenses (see 10 CFR Part 50) that is technically relevant to the design and not site specific. In accordance with the requirements of 10 CFR 52.79(b) and 10 CFR 50.34(b)(6)(iii), an applicant for an operating license shall provide information concerning plans for preoperational testing and initial operations. RG 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants," Revision 2, dated August 1978, describes the general scope and depth of the initial test programs acceptable to the NRC staff for light-water-cooled nuclear power plants. Additionally, SRP Section 14.2, "Initial Test Program," Revision 2, dated July 1981, provides guidance to the NRC staff for the review of a proposed initial test program.

As stated in RG 1.68, the primary objectives of an acceptable initial test program are (1) to provide assurance through testing that the facility has been adequately designed, (2) to validate, to the extent practical, the analytical models and verify the correctness or conservatism of assumptions used to predict plant responses to anticipated transients and postulated accidents, (3) to provide assurance through testing that construction and installation of equipment in the facility have been accomplished in accordance with the design, (4) to familiarize the plant's operating staff with the operation of the facility, and (5) to verify by trial use, to the extent practical, the adequacy of the facility's operating procedures and emergency operating procedures.

For each phase of the initial test program, a design certification applicant should provide test abstracts which include the objectives of each test, a summary of prerequisites and test method, and specific acceptance criteria. The initial test program should also address programmatic aspects, including consideration of organization and staffing; preparation, review, and technical content of test procedures; conduct of the test program; review, evaluation, and approval of test results; and utilization of reactor operating and testing experiences. Conformance of a proposed test program to the guidelines of RG 1.68 and the acceptance criteria outlined in SRP Section 14.2 provide reasonable assurance it meets these objectives. Initial test programs that satisfy these objectives should provide the necessary assurance that the facility can be operated in accordance with its design criteria and in a manner that will not endanger the health and safety of the public.

14.2.1.2 AP1000 Initial Test Program Review Methodology

DCD Tier 2, Section 14.2 describes the initial AP1000 test program, including preoperational and startup tests. Preoperational tests, which are performed after the construction and installation of plant equipment, but before initial fuel loading, demonstrate the capability of the plant systems to meet relevant performance requirements. Startup tests, which begin with initial fuel loading, demonstrate the capability of the integrated plant to meet performance requirements. Using the guidance contained in SRP Section 14.2, the staff reviewed the AP1000 test program administrative requirements and the technical adequacy of the preoperational and startup tests. The staff's initial test program review methodology consisted of (1) reviewing the test program's conformance with NRC RG regulatory positions related to testing; (2) designing a specific technical review to ensure that the test program adequately demonstrates the performance of the AP1000 structures, systems, and components (SSCs) important to safety; and (3) comparing the AP1000 test program to the previously reviewed and approved initial test program for the AP600. Each of these three review activities is described below:

14.2.1.2.1 Test Program Conformance with NRC Regulatory Guidance

In accordance with SRP Section 14.2, Item I.3, "Test Program's Conformance with Regulatory Guides," the staff reviewed the applicant's plans for achieving conformance with the RGs applicable to the initial test program. SRP Section 14.2 and RG 1.68 provide references to specific RGs applicable to the initial test program, as determined by the staff. For those instances in which the applicant did not conform to the RGs, the staff reviewed the applicant's justification for the exception to ensure that the test program scope remained sufficient. Section 14.2.7 of this report provides additional information.

14.2.1.2.2 Design-Specific Technical Review

Because the RGs and SRP Section 14.2 provide only representative guidance for the initial plant testing scope, the staff completed a design-specific testing review to verify that the test program would satisfactorily demonstrate the AP1000 plant features important to safety. When the initial AP1000 draft safety evaluation report (DSER) was issued on June 16, 2003, the staff had not completed this design-specific technical review. Therefore, the staff identified completion of this review as Open Item 14.2-1 in the DSER.

To ensure the adequacy of the AP1000 testing scope, general test methods, and test program acceptance criteria, the staff developed a review plan to address closure of Open Item 14.2-1. The review plan consisted of the following activities:

- Verify that the AP1000 initial test program adequately demonstrates the performance of SSCs important to safety. For the purposes of this testing review, the staff considered SSCs that (1) were safety-related, (2) within the scope of regulatory treatment of non-safety systems (RTNSS), or (3) within the scope of the design reliability assurance program (D-RAP) as important to safety.

- Verify that test abstracts included in DCD Tier 2, Section 14.2 adequately describe the required testing. The staff review focused on verifying that the applicant had adequately described the proposed testing method and acceptance criteria, that the testing could be accomplished as described, that the testing would not subject the plant to an unsafe condition, and that the applicant had assigned the testing to an appropriate test phase in order to minimize reliance on untested equipment.

- Verify that the preoperational test program was consistent with the system-based inspections, tests, analyses, and acceptance criteria (ITAAC) described in DCD Tier 1 information. This review ensured that the preoperational testing abstracts contained in DCD Tier 2, Chapter 14.2, were consistent with ITAAC requirements. Additionally, the staff verified that the preoccupational test program included all initial test program activities associated with the ITAAC and that they would be accomplished prior to initial fuel loading. Section 14.3 of this report discusses the staff's review of the ITAAC in further detail.

In the course of this review activity, the staff identified 28 specific areas where additional information was required from the applicant to complete the design-specific testing review. The staff identified each of these areas with an alphanumeric designator as a subpart to Open Item 14.2-1 (designated as Open Items 14.2-1.a through 14.2-1.bb). By E-mails dated August 12, 15, and 28, 2003, the NRC forwarded requests for additional information (RAIs) pertaining to Open Items 14.2-1.a through 14.2-1.bb to support closure of Open Item 14.2-1. On August 26, 2003, the applicant provided additional information to address 26 of the 28 issues identified by the NRC staff in Open Items 14.2-1.a through 14.2-1.z. On September 8, 2003, the applicant provided additional information to address Open Items 14.2-1.aa and 14.2-1.bb. The applicant revised DCD Tier 2, Section 14.2 to address Open Items 14.2-1.a through 14.2-1.z. Sections 14.2.9 and 14.2.10 of this report discuss the resolution of each of these 28 issues.

14.2.1.2.3 Comparison of the AP1000 to the AP600 Initial Test Program

The staff noted that the major safety-related and risk-significant system functions of the AP1000 design are similar to those of the AP600 design. The NRC staff previously reviewed and accepted the AP600 initial test program specified in Section 14.2 of NRC technical report (NUREG)-1512, "Final Safety Evaluation Report Related to the Certification of the AP600 Standard Design." Therefore, the staff reviewed the differences between the AP1000 and AP600 initial test programs in order to gain added assurance that the scope of the AP1000 test program was adequate. This portion of the staff review focused on (1) identification of differences between the proposed AP1000 test program and the AP600 test program, and (2) applicability of the AP600 test program to the AP1000 design. When the NRC staff identified differences between the AP600 and AP1000 test programs, it conducted additional reviews to verify the adequacy of the AP1000 test program. The associated sections below describe these additional reviews.

14.2.2 Organization and Staffing

In DCD Tier 2, Section 14.2.2, "Organization, Staffing, and Responsibilities," the applicant stated that the combined license (COL) holder is responsible for developing the specific plant organization and staffing appropriate for testing, operating, and maintaining the AP1000 plant. Further, the applicant identified this issue as a COL applicant responsibility in DCD Tier 2, Section 14.4.1. Because facility staffing will be determined by the COL applicant and is outside the scope of design certification, the NRC staff determined that it is acceptable to defer responsibility for the description of specific staff, staff responsibilities, authorities, and personnel qualifications for the AP1000 initial test program to the COL applicant. This is COL Action Item 14.4-1. Section 14.4 of this report discusses this item further.

14.2.3 Test Procedures

SRP Section 14.2 and RG 1.68 specify that test procedures should control the sequencing of testing steps; the preparation, review, and approval of test procedures; the use of temporary equipment; and the acceptance criteria. In DCD Tier 2, Section 14.4.2, "Test Specifications and Procedures," the applicant stated that the COL applicant is responsible for providing test specifications and test procedures for preoperational and startup tests for review by the NRC. Additionally, the applicant stated that it will provide specifications and procedures for startup tests to NRC inspection personnel not less than 60 days prior to the scheduled fuel loading date, and that it will provide copies of the test specifications and test procedures for systems or components that perform safety-related or non-safety defense-in-depth functions to NRC inspection personnel approximately 60 days prior to the scheduled performance of the preoperational tests. Although the applicant proposed to defer test procedure preparation to the COL phase, DCD Tier 2, Section 14.2.3, "Test Specifications and Test Procedures," provides general guidance for development and review of test specifications and procedures. The general guidelines include specification of test objectives, prerequisites, initial conditions, and criteria for evaluating and reconciling test results. The NRC staff concluded that the general test specification and test procedure guidelines specified in DCD Tier 2, Section 14.2.3, are acceptable because the guidelines are consistent with RG 1.68 and SRP Section 14.2 recommendations for test procedure content and development applicable to design certification. Because development of initial test program test procedures will require detailed plant-specific design information and review and approval by the COL applicant, the NRC staff concurs that deferring responsibility for the development of detailed preoperational and startup test specifications and procedures to the COL applicant is acceptable. This is COL Action Item 14.4-2. Section 14.4 of this report describes this item in more detail.

14.2.4 Review, Evaluation, and Approval of Test Results

In DCD Tier 2, Section 14.4.4, "Review and Evaluation of Test Results," the applicant stated that the COL applicant and holder *is responsible for the review and evaluation of individual test* results. In as much as test results will not be available until a facility is built, the NRC staff determined that it is appropriate and acceptable to defer the review and evaluation of individual test results to the COL applicant or COL holder, as appropriate. This is COL Action Item 14.4-4. Section 14.4 of this report provides additional detail on this item.

14.2.5 Utilization of Reactor Operating and Testing Experiences in the Development of the Test Program

SRP Section 14.2 states that the applicant should describe how it used the operating and testing experiences of other facilitates in the initial test program. DCD Tier 2, Section 14.2.5, "Utilization of Reactor Operating and Testing Experiences in the Development of the Test Program," states the following:

> The design, testing, startup, and operating experience from previous pressurized water reactor plants is utilized in the development of the initial preoperational and startup test program for the AP1000 plant. Other sources of experience reported and described in various documents such as NRC reports, including NRC bulletins, and Institute of Nuclear Power Operations (INPO) reports including Significant Operating Event Reports (SOERs), are also utilized in the AP1000 initial preoperational and startup test program.

The NRC staff noted that DCD Tier 2, Section 14.2.3, states that "available information on operating or testing experiences of operating reactors are factored into the test specifications and test procedures as appropriate." In DCD Tier 2, Section 14.4.2, the applicant stated that the COL applicant is responsible for providing test specifications and test procedures for preoperational and startup tests for review by the NRC. Additionally, DCD Tier 2, Section 14.4.3, states that the COL applicant is responsible for preparing a startup administration manual which contains the administrative procedures and standards that govern the activities associated with the plant initial test program. Therefore, the NRC staff finds it acceptable to defer the review of the utilization of operating and testing experience to the COL phase. COL Action Items 14.4-2 and 14.4-3 encompass this issue.

14.2.5.1 Special Tests for Initial AP1000 Plants

In DCD Tier 2, Section 14.2.5, the applicant stated that performance of nine special preoperational and initial operation tests would be necessary only for the first one or the first three AP1000 plants. The applicant proposed that subsequent plants may omit performance of these special tests after providing suitable justification. Seven of these tests are referred to as "first-plant-only" tests, while the remaining two of these tests are referred to as "first-three-plant" tests. As described in DCD Tier 2, Section 14.2.5, these special tests are associated with the establishment of certain unique phenomenological performance parameters of the AP1000 that will not change from plant to plant. Additionally, the performance of the "first-three-plant" tests are intended to affirm consistent passive system functions prior to allowing a subsequent COL applicant to omit performance of the testing. The following sections describe each of these special tests:

14.2.5.1.1 First-Plant-Only Tests

- In-Containment Refueling Water Storage Tank (IRWST) Heatup Test (DCD Tier 2, Section 14.2.9.1.3, "Passive Core Cooling System Testing," Item (h))

  During preoperational testing of the passive core cooling system, thermocouples will be placed in the in-containment refueling water storage tank (IRWST) to observe the thermal profile developed during the heatup of the IRWST water during operation of the passive residual heat removal system heat exchanger (PRHR HX). This test will confirm the results of the AP1000 design certification program passive residual heat removal (PRHR) tests with regard to IRWST mixing, and quantify the conservatism in the transient analyses described in DCD Tier 2, Chapter 15, "Accident Analyses." The applicant stated that as a result of the standardization of the AP1000, the heatup and thermal stratification characteristics of the IRWST will not vary from plant to plant. Consequently, the applicant classified this test as a first plant-only test.

- Pressurizer Surge Line Stratification Evaluation (DCD Tier 2, Section 14.2.9.1.7, "Expansion, Vibration and Dynamic Effects Testing," Item (d))

  The NRC Bulletin (BL) 88-11, "Pressurizer Surge Line Thermal Stratification," requested all applicants for a pressurized-water reactor (PWR) operating license to verify piping code conformance by analysis and hot functional testing. As part of the AP1000's conformance to NRC BL 88-11, the applicant stated that the COL applicant will implement a monitoring program for the first AP1000 plant. This monitoring program will include recording temperature distributions and thermal displacements of the surge line piping during hot functional testing and during the first fuel cycle, as discussed in DCD Tier 2, Section 3.9.3, "ASME Code Classes 1, 2, and 3 Components, Component Supports, and Core Support Structures."

- Reactor Vessel Internals Vibration Testing (DCD Tier 2, Section 14.2.9.1.9, "Reactor Vessel Internals Vibration Testing")

  The preoperational vibration test program for the reactor internals to be conducted on the first AP1000 plant is consistent with the guidelines of RG 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing," for a comprehensive vibration assessment program. DCD Tier 2, Section 3.9.2, "Dynamic Tests and Analysis," discusses this program.

- Natural Circulation Tests (DCD Tier 2, Sections 14.2.10.3.6, "Natural Circulation," and 14.2.10.3.7, "Passive Residual Heat Removal Heat Exchanger")

  Natural circulation tests using the steam generators (SGs) and the PRHR HX will be performed at low-core power during the startup test phase. The applicant classified this test as a first-plant-only test because its purpose is to obtain data to benchmark the operator training simulator.

- Rod Cluster Control Assembly Out-of-Bank Measurements (DCD Tier 2, Section 14.2.10.4.6, "Rod Cluster Control Assembly Out-of-Bank Measurements")

  Rod cluster control assembly out-of-bank measurements are performed during power ascension tests. The test is performed between 30 to 50 percent power so that the plant does not exceed peaking factor limits. The applicant stated that this test is required to be performed only for the first plant because its purpose is to validate calculation tools and instrument responses.

- Load Follow Demonstration Test (DCD Tier 2, Section 14.2.10.4.22, "Load Follow Demonstration")

  Although RG 1.68 does not specify a load follow demonstration test, the AP1000 performs load follow with grey control rods. Therefore, the applicant has included a proof of principle load follow demonstration for the first AP1000 plant to demonstrate its ability to follow a design-basis daily load follow cycle.

14.2.5.1.2 First-Three-Plant Tests

- Core Makeup Tank (CMT) Heated Recirculation Tests (DCD Tier 2, Section 14.2.9.1.3, Items (k) and (w))

  During preoperational testing of the passive core cooling system, a natural circulation heatup of the CMTs, followed by a test to verify the ability of the CMTs to transition from a recirculation mode to a draindown mode while at elevated temperature and pressure, will be performed. The applicant classified this test as a first-three-plant test because the natural circulation of the CMTs will not vary from plant to plant. Additionally, the applicant noted that performance of this test results in significant thermal transients on Class 1 components, including the CMTs and the direct vessel injection nozzles.

- Automatic Depressurization System (ADS) Blowdown Test (DCD Tier 2, Section 14.2.9.1.3, Item(s))

  During preoperational hot functional testing of the reactor coolant system (RCS), an ADS blowdown test will be performed. This will result in a significant blowdown of the RCS into the IRWST. This test verifies proper operation of the ADS valves and demonstrates the proper operation of the ADS spargers to limit the hydrodynamic loads in containment to less than design limits. The applicant classified this test as a first-three-plant test because operation of the ADS and the resultant hydrodynamic loads will not vary from plant to plant. Additionally, the applicant noted that performance of this test results in significant thermal transients on Class 1 components, including the primary components. It also results in hydrodynamic loads in containment, including the IRWST.

The NRC staff noted that DCD Tier 2, Section 14.4.6, "First-Plant-Only and Three-Plant-Only Tests," states the following:

> The COL applicant or holder for the first plant and the first three plants will perform the tests listed in [DCD Tier 2, Section] 14.2.5. For subsequent plants, the COL applicant or licensee shall either perform the tests listed in [DCD Tier 2, Section] 14.2.5, or shall provide a justification that the results of the first-plant-only tests or the first-three-plant tests are applicable to the subsequent plant.

The staff reviewed the information provided by the applicant in DCD Tier 2, Section 14.2.5, regarding the performance of certain special tests on a first-plant-only and first-three-plant-only basis. The staff noted that DCD Tier 2, Section 14.4.6, "First-Plant-Only and Three-Plant-Only," provides that the COL applicant or licensee for the first plant or the first three plants will perform the tests listed in DCD Tier 2, Section 14.2.5. DCD Tier 2, Section 14.4.6, further provides that for subsequent plants, the COL applicant or licensee shall either perform the tests listed in DCD Tier 2, Section 14.2.5, or shall justify that the results of the first-plant-only tests or the first-three-plant tests apply to subsequent plants. Based on this information, the staff concludes that it is the responsibility of a subsequent COL holder to either perform or justify not performing any of the special tests identified in DCD Tier 2, Section 14.2.5. Therefore, the staff will obtain additional information during the COL application stage to determine the acceptability of performance of these special tests on a first-plant-only or first-three-plant basis. Consequently, the staff has not evaluated the acceptability of performing these special tests on either a first-plant-only or first-three-plant basis during the design certification review. This is COL Action Item 14.4-6. Section 14.4 of this report discusses this item further.

14.2.6 Trial Use of Plant Operating and Emergency Procedures

SRP Section 14.2 states that the applicant should incorporate the plant operating, emergency, and surveillance procedures into the test program or otherwise verify these procedures through use, to the extent practicable during the test program. In DCD Tier 2, Section 14.2.6, "Use of Plant Operating and Emergency Procedures," the applicant stated that as appropriate and to the extent practical plant normal, abnormal, and emergency operating procedures will be used when performing preoperational startup tests. In DCD Tier 2, Section 14.4.2, the applicant stated that the COL applicant is responsible for providing specifications and procedures for preoperational and startup tests for review by the NRC. Additionally, DCD Tier 2, Section 14.4.3, "Conduct of Test Program," indicates that the COL applicant is responsible for a startup administration manual which contains the administrative procedures and standards that govern the activities associated with the plant initial test program. Therefore, the NRC staff concludes it is acceptable to defer the review of the trial use of operating and emergency procedures to the COL phase. COL Action Items 14.4-2 and 14.4-3 encompass this issue.

14.2.7 Conformance of Test Programs with Regulatory Guides

SRP Section 14.2 states, in part, that the applicant should establish and describe an initial test program that is consistent with the regulatory positions in RG 1.68. Additionally, SRP Section 14.2 includes a list of supplemental RGs that provide more detailed information pertaining to the testing. The supplemental RGs contain additional information to help determine if performance of the tests in the proposed manner will likely accomplish the objectives of certain plant tests. The NRC staff reviewed the AP1000 initial test program to verify that the program either complied with these RGs or that the applicant provided adequate justification for exceptions.

DCD Tier 2, Appendix 1A, "Conformance with Regulatory Guides," describes compliance of the AP1000 initial test program with the NRC RGs applicable to the test program. The applicant identified several areas where the proposed AP1000 test program did not conform to staff regulatory positions. The staff reviewed each proposed RG exception to verify that the applicant provided adequate justification for nonconformance with testing regulatory positions. The staff evaluated each of these specific exceptions, as described below:

- RG 1.41, "Preoperational Testing of Redundant On-Site Electric Power Systems to Verify Proper Load Group Assignments," Revision 0

  RG 1.41 states that, as part of the preoperational testing program, certain onsite electrical power systems should be tested to verify the existence of independence among redundant onsite power sources and their load groups. In DCD Tier 2, Appendix 1A, the applicant provided the following information related to RG 1.41:

  > The guidelines are followed for Class 1E dc [direct current] power systems during the preoperational testing of the AP1000 redundant onsite electric power systems to verify proper load group assignments, except as follows. Complete preoperational testing of the startup, sequence loading, and functional performance of the load groups is performed where practical. In those cases where it is not practical to perform complete functional performance testing, an evaluation is used to supplement the testing.

  The staff initially lacked sufficient information to determine the acceptability of this exception to RG 1.41. Specifically, the staff could not identify to which regulatory position in RG 1.41 the exception applied, if the exception applied to both alternating current (ac) and dc systems, and in which cases the performance of functional testing was not practical. Therefore, in RAI 261.014, the staff requested the applicant to provide additional specific information regarding this exception. This was Open Item 14.2.7-1 in the DSER.

The staff requested, in RAI 260.014, the applicant to identify (1) the specific regulatory position in RG 1.41 that the does not conform to the AP1000 test program; (2) the specific electrical systems (ac, dc, or both) affected by the exception; and (3) the specific cases in which performance of functional testing was not practical. The staff also requested the applicant provide supporting justification. The applicant responded to RAI 261.014 by letter dated May 14, 2003, and stated that RG 1.41 applies only to the Class 1E dc and uninterrruptible power supply (UPS) system. The applicant clarified that the proposed exception applies to the portion of RG 1.41, Regulatory Position 2, that requires functional performance testing of squib valve electrical loading. The applicant stated that while functional testing of squib valves powered from the Class 1E dc and UPS system is not practical, testing of other load types on the Class 1E dc and UPS system according to RG 1.41 is reasonable. The applicant stated that the electrical connection at the squib valve actuator would be removed and the leads connected to a test device to confirm the presence or absence of an actuation signal. Because energizing a squib valve would be a destructive test, the staff concluded that the exception to RG 1.41 for the functional testing of squib valves connected to the Class 1E dc and UPS system is reasonable. Based on this response to RAI 261.014 and Open Item 14.2.7-1, the NRC staff determined that this response was acceptable; therefore, Open Item 14.2.7-1 is resolved.

- RG 1.68, "Initial Test Program for Water-Cooled Nuclear Power Plants," Revision 2, Appendix A, Test 4.t

RG 1.68, Appendix A, Test 4.t specifies performance of natural circulation tests of the reactor coolant system during low power testing. In DCD Tier 2, Appendix 1A, the applicant provided the following information:

> For the AP1000, natural circulation heat removal to cold conditions using the steam generators is not safety-related, as in current plants. This safety function is performed by the PRHR. Natural circulation heat removal via the PRHR is tested for every plant during hot functional testing.

Because the PRHR HX serves as the safety-related heat sink for the AP1000 design, the staff determined that natural circulation testing of the PRHR, rather than the reactor coolant system and SGs, met the intent of RG 1.68 and was therefore acceptable. However, the NRC found that the exception to RG 1.68, Appendix A, Test 4.t contradicts the low-power test abstracts in DCD Tier 2, Section 14.2.10.3.6, "Natural Circulation (First Plant Only)," and DCD Tier 2, Section 14.2.10.3.7, "Passive Residual Heat Removal Heat Exchanger (First Plant Only)." Specifically, the exception to RG 1.68

states, in part, that "the PRHR is tested for every plant during hot functional testing." However, the low-power natural circulation test abstracts 14.2.10.3.6 and 14.2.10.3.7 state that these tests are "first-plant-only" tests.

Additionally, DCD Tier 2, Section 14.2.10.3.7, stated, in part, that performance of the PRHR natural circulation testing is not required if a large-scale test of the AP600 or AP1000 type PRHR HX has been conducted and confirms adequate heat removal capability. Because of the conflicting information contained in the DCD, the staff initially could not complete the review of this regulatory position exception. Therefore, in RAI 261.015, the NRC staff requested the applicant to clarify and justify the inconsistent natural circulation testing provisions in test abstracts 14.2.10.3.6 and 14.2.10.3.7. Specifically, the staff asked the applicant to clarify the circumstances under which it would perform natural circulating testing. This issue was Open Item 14.2.7-2 in the DSER. Additionally, in Open Item 14.2-1.v, the staff requested the applicant to clarify or delete the note in test abstract 14.2.10.3.7 regarding the use of a large-scale test facility in lieu of an actual plant low-power test.

In response to Open Items 14.2-1.v and 14.2.7-2, the applicant deleted the reference to large-scale test facility testing in low-power test abstract 14.2.10.3.7 to preclude the use of large-scale testing in lieu of actual plant testing. Additionally, the applicant revised the comments associated with the exception to RG 1.68, Appendix A, Test 4.t referenced in DCD Tier 2, Appendix 1A, to delete the reference to performing natural circulation testing during hot functional testing for every plant. The staff noted that the preoperational test program includes testing to verify natural circulation heat removal capability in test abstract 14.2.9.1.3, "Passive Core Cooling System Testing." This action resolves Open Items 14.2-1.v and 14.2.7-2. However, the staff will require additional information during the COL application stage to determine the acceptability of performing tests 14.2.10.3.6 and 14.2.10.3.7 on a first-plant-only basis. This is COL Action Item 14.4-6. Section 14.4 of this report discusses this item further.

- RG 1.68, "Initial Test Program for Water-Cooled Nuclear Power Plants," Regulatory Position C.1, Appendix A.5, Power Ascension Tests

RG 1.68, Regulatory Position C.1, states that testing of SSCs used for shutdown and cooldown of the reactor under normal, transient, and postulated accident conditions should be conducted. In DCD Tier 2, Section 1.9.4, "Generic Issue," I.G.2, "Scope of Test Program," the applicant states:

> The conformance with Standard Review Plan, Section 14 is outlined in AP1000 Compliance with SRP Acceptance Criteria, WCAP-15799.

In WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," Revision 0, dated April 2002, the NRC staff found that the applicant took exception to the remote shutdown panel testing described in RG 1.68, Regulatory Position C.1. The applicant stated the following:

> Since the remote shutdown panel is similar to the main control room work station, it is unnecessary to perform a preoperational test to place the plant in safe-shutdown condition and maintain it there from the remote shutdown workstation. Remote shutdown capability testing is performed by testing the controls and indications of the remote shutdown workstation and separately demonstrating the ability of the PRHR system to maintain safe shutdown.

The NRC staff concluded that the reference to performance of this test during the preoperational test phase is inconsistent with the guidance in RG 1.68. Specifically, RG 1.68, Appendix A, Test 5.d.d, recommends performing this test during the power ascension test phase, rather than during the preoperational test phase.

The staff reviewed the test abstract in DCD Tier 2, Section 14.2.10.4.28, "Remote Shutdown Workstation," and finds that the DCD specifies that this test is to be performed during the power ascension test phase when the plant is operating in a steady-state condition at 10–20 percent power. Accordingly, the staff concludes that the remote shutdown workstation test abstract in DCD Tier 2, Chapter 14, meets the guidance in RG 1.68 relating to Test 5.d.d and is, therefore, acceptable. Because the applicant conformed with the RG 1.68 guidance for remote shutdown panel testing, the staff concluded that the applicant should delete this unnecessary RG exception from WCAP-15799. This was Open Item 14.2.7-3 in the DSER.

In response to DSER Open Item 14.2.7-3, the applicant prepared Revision 1 to WCAP-15799, dated August 2003, which states that test abstract 14.2.10.4.28 meets the guidance relating to Test 5.d.d in Appendix A.5 to RG 1.68, Regulatory Position C.1. The staff finds this revision to be acceptable. Therefore, Open Item 14.2.7-3 is resolved.

- RG 1.140, "Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," Revision 1, Regulatory Positions C.1 and C.2.a-b

  RG 1.140, Regulatory Positions C.1 and C.2.a-b, provide design criteria, including operating parameters, instrumentation, and seismic capabilities, for atmospheric cleanup systems installed in a normal ventilation exhaust system. In DCD Tier 2, Appendix 1A, the applicant identified exceptions to Regulatory Positions C.1 and C.2a-b contained in Revision 1 to RG 1.140. The NRC staff reviewed the exceptions to RG 1.140 and noted that the applicant had not evaluated whether the AP1000 design conforms to Revision 2 of RG 1.140, issued in June 2001. In RAI 480.007, the staff requested the applicant to conform to Regulatory Positions C.1 and C.2.1-2.4 in Revision 2 of RG 1.140. The applicant revised DCD Tier 2, Appendix 1A, to indicate the applicant's conformance with RG 1.140, Revision 2, Regulatory Positions C.1 and C.2.1-2.4. The staff concludes that the applicant adequately addressed this issue. Therefore, RAI 480.007 is resolved.

- RG 1.128, "Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants"

RG 1.128 states that, with certain exceptions, conformance with Institute of Electrical and Electronics Engineers (IEEE) Standard (Std) 484-75 provides an adequate basis for complying with the requirements of Appendix A and Appendix B to 10 CFR Part 50 with respect to quality standards for the installation design and installation of large lead storage batteries.

The applicant states the following in DCD Tier 2, Appendix 1A:

> Regulatory Guide 1.128 endorses IEEE Std 484-75 ([DCD] Reference 36) which has been superseded by IEEE Std 484-1996 ([DCD] Reference 37). The AP1000 uses the latest version of the industry standard (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.128.

The staff compared the standards contained in the 1975 and 1996 versions of IEEE Std 484 and determined that the use of IEEE Std 484-1996 for the testing of large lead storage batteries is equivalent to the testing required by IEEE Std 484-75. Because testing performed in accordance with IEEE Std 484-1996 achieves the same purpose as testing in accordance with RG 1.128, the staff finds this exception to RG 1.128 to be acceptable.

- RG 1.139, "Guidance for Residual Heat Removal (for Comment)"

In RG 1.139, Regulatory Positions C.1.a and C.1.c specify that the design should allow the reactor to be taken from normal operating conditions to cold shutdown using only safety-grade systems that satisfy General Design Criteria (GDC) 1 through 5. Additionally, the systems should be capable of bringing the reactor coolant system to a cold-shutdown condition within 36 hours following shutdown with only offsite power or onsite power available, assuming the most limiting single failure.

The applicant states the following in DCD Tier 2, Appendix 1A:

> Continued operation of the [passive residual heat removal] heat exchanger brings the reactor coolant system pressure and temperature down to the point where the stress in the reactor coolant pressure boundary is low. This temperature is about [204 °C] 400 °F which allows a reactor coolant system pressure of 1/10 of design ([1.72 MPa] 250 psia).
>
> The passive residual heat removal heat exchanger does not rely on pumps, ac power sources, air systems, or water cooling systems.

For the AP1000 design, the staff noted in Section 6.3.1.4 of this report, that for non-loss-of-coolant accident (non-LOCA) events, the PRHR HX, in conjunction with the passive containment coolant system, can bring the plant to a stable safe-shutdown condition and cool the RCS to about 215.6 °C (420 °F) in 36 hours, with or without the reactor coolant pumps operating. In DCD Tier 2, Chapter 16, "Technical Specifications," Table 1.1-1, Mode 4, "Safe Shutdown" is defined to occur when the average reactor coolant temperature is between 215.6 °C $\geq T_{avg} >$ 93.3 °C (420 °F $\geq T_{avg} >$ 200 °F). Thus, the PRHR can reach the safe-shutdown condition, as defined in the AP1000 technical specifications (TS), within 36 hours. The normal residual heat removal system can be used to reach Mode 5 (cold shutdown) condition with $T_{avg} \leq$ 93.3 °C ($T_{avg} \leq$ 200 °F) in a time period greater than 36 hours. Accordingly, although RG 1.139 specifies that the residual heat removal system should be capable of achieving a cold shutdown condition within 36 hours, the staff finds it acceptable to use the safety-related PRHR to bring the plant to safe-shutdown condition of less than 215.6 °C (420 °F) because of its functional limitations. The staff addressed this position regarding the PRHR in passive plant designs in SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety System in Passive Plant Designs," which the Commission approved in the Staff Requirements Memorandum (SRM) dated June 30, 1994. In addition, the staff finds that the safety-grade PRHR system requires only dc power to achieve safe-shutdown conditions and can perform its function regardless of the availability of offsite or onsite ac power. Therefore, the staff finds the exceptions to RG 1.139 outlined in DCD Tier 2, Appendix 1A to be acceptable.

- Regulatory guides referenced in DCD Tier 2, Appendix 1A

  The NRC staff also reviewed all RGs referenced in DCD Tier 2, Appendix 1A and recommended by SRP Section 14.2 that the applicant had determined not to be applicable to the AP1000 design. They include the following:

  - RG 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants"

  - RG 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants"

  - RG 1.95, (WITHDRAWN January 2002), "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release"

  - RG 1.116, "Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems"

  - RG 1.136, "Materials, Construction, and Testing of Concrete Containments (Articles CC-1000, -2000, and -4000 through -6000 of the 'Code for Concrete Reactor Vessels and Containments')"

> Because the AP1000 design does not include a concrete containment, Class 1E diesel generators, or safety-related engineered safeguards ventilation cleanup systems, the staff finds that RGs 1.9, 1.52, and 1.136 do not apply to the AP1000 design certification. Additionally, the NRC withdrew RG 1.95, and therefore, it is not applicable to a design certification review. Finally, RG 1.116 applies to the installation, inspection, and testing of plant equipment during construction and is, therefore, not applicable to design certification. Consequently, the staff concludes that these five RGs do not apply to the AP1000 design certification.

The NRC staff finds that the AP1000 test program adequately conforms to RG 1.68 and the test program regulatory positions stated in SRP Section 14.2, and that the applicant has adequately justified any exceptions.

14.2.8 Test Program Schedule and Sequence

SRP Section 14.2, Subpart II.7, "Test Program Schedule and Sequence," states, in part, that the test program schedule should establish that testing will be accomplished as early in the test program as feasible, and that the safety of the plant will not depend entirely on the performance of untested systems, components, or features.

In DCD Tier 2, Section 14.2.8, "Test Program Schedule," the applicant stated the following:

> The schedule for the initial fuel load and for each major phase of the initial test program includes the timetable for generation, review and approval of procedures as well as the actual testing and analysis of results.
>
> Preoperational testing is performed as systems and equipment availability allows. The interdependence of systems is considered.
>
> Sequencing of startup tests depends on specified power and flow conditions and intersystem prerequisites. The startup test schedule establishes that, prior to core load, the test requirements are met for those plant structures, systems, and components that are relied upon to prevent, limit or mitigate the consequences of postulated accidents. Testing is sequenced so that the safety of the plant is not dependent on untested systems, components, or features.

The COL applicant is responsible for the test program schedule. Therefore, the staff finds it acceptable to defer the review of the test program schedule and sequence to the COL phase. COL Action Items 14.4-1, 14.4-2, and 14.4-3 encompass this issue.

14.2.9 Preoperational Test Abstracts

Preoperational testing consists of tests conducted following completion of construction and construction-related inspection and tests, but prior to fuel loading. Preoperational testing will demonstrate, to the extent practical, the capability of SSCs to meet design criteria. The extent of testing should be sufficient to demonstrate that the facility can operate in accordance with the design criteria. The scope of preoperational testing should also ensure that plant safety during later phases, including initial fuel loading and startup testing, does not depend entirely on untested systems.

In DCD Tier 2, Section 14.2.9, "Preoperational Test Descriptions," the applicant provided 16 test abstracts for safety-related functions, 21 test abstracts for non-safety-related, defense-in-depth functions, 6 test abstracts for non-safety-related radioactive system functions, and 21 test abstracts for additional non-safety-related functions. The following is a list of the preoperational test abstracts found in DCD Tier 2, Section 14.2.9:

Safety-Related Functions

14.2.9.1.1 Reactor Coolant System Testing
14.2.9.1.2 Steam Generator System Testing
14.2.9.1.3 Passive Core Cooling System Testing
14.2.9.1.4 Passive Containment Cooling System Testing
14.2.9.1.5 Chemical and Volume Control System Isolation Testing
14.2.9.1.6 Main Control Room Emergency Habitability System Testing
14.2.9.1.7 Expansion, Vibration and Dynamic Effects Testing
14.2.9.1.8 Control Rod Drive System
14.2.9.1.9 Reactor Vessel Internals Vibration Testing
14.2.9.1.10 Containment Isolation and Leak Rate Testing
14.2.9.1.11 Containment Hydrogen Control System Testing
14.2.9.1.12 Protection and Safety Monitoring System Testing
14.2.9.1.13 Incore Instrumentation System Testing
14.2.9.1.14 Class 1E DC Power and Uninterruptable Power Supply Testing
14.2.9.1.15 Fuel Handling and Reactor Component Servicing Equipment Test
14.2.9.1.16 Long Term Safety-Related System Support Testing

Defense-in-Depth Functions

14.2.9.2.1 Main Steam System Testing
14.2.9.2.2 Main and Startup Feedwater System
14.2.9.2.3 Chemical and Volume Control System Testing
14.2.9.2.4 Normal Residual Heat Removal System Testing
14.2.9.2.5 Component Cooling Water System Testing
14.2.9.2.6 Service Water System Testing
14.2.9.2.7 Spent Fuel Pool Cooling System Testing
14.2.9.2.8 Fire Protection System Testing
14.2.9.2.9 Central Chilled Water System Testing
14.2.9.2.10 Nuclear Island Non-radioactive Ventilation System Testing
14.2.9.2.11 Radiologically Controlled Area Ventilation System
14.2.9.2.12 Plant Control System Testing
14.2.9.2.13 Data Display Processing System Testing
14.2.9.2.14 Diverse Actuation System Testing

14.2.9.2.15 Main AC Power System Testing
14.2.9.2.16 Non-Class 1E DC and Uninterruptable Power Supply System Testing
14.2.9.2.17 Standby Diesel Generator Testing
14.2.9.2.18 Radiation Monitoring System Testing
14.2.9.2.19 Plant Lighting System Testing
14.2.9.2.20 Primary Sampling System Testing
14.2.9.2.21 Annex/Auxiliary Building Nonradioactive HVAC System

Non-Safety-Related Radioactive System Functions

14.2.9.3.1 Liquid Radwaste System Testing
14.2.9.3.2 Gaseous Radwaste System Testing
14.2.9.3.3 Solid Radwaste System Testing
14.2.9.3.4 Radioactive Waste Drain System Testing
14.2.9.3.5 Steam Generator Blowdown System Testing
14.2.9.3.6 Waste Water System Testing

Additional Non-Safety-Related Functions

14.2.9.4.1 Condensate System Testing
14.2.9.4.2 Condenser Air Removal System Testing
14.2.9.4.3 Main Turbine System and Auxiliaries Testing
14.2.9.4.4 Main Generator System and Auxiliaries Testing
14.2.9.4.5 Turbine Building Closed Cooling Water System Testing
14.2.9.4.6 Circulating Water System Testing
14.2.9.4.7 Turbine Island Chemical Feed System Testing
14.2.9.4.8 Condensate Polishing System Testing
14.2.9.4.9 Demineralized Water Transfer and Storage System Testing
14.2.9.4.10 Compressed and Instrument Air System Testing
14.2.9.4.11 Containment Recirculation Cooling System Testing
14.2.9.4.12 Containment Air Filtration System Testing
14.2.9.4.13 Plant Communications System Testing
14.2.9.4.14 Mechanical Handling System Crane Testing
14.2.9.4.15 Seismic Monitoring System Testing
14.2.9.4.16 Special Monitoring System Testing
14.2.9.4.17 Secondary Sampling System Testing
14.2.9.4.18 Turbine Building Ventilation System
14.2.9.4.19 Health Physics and Hot Machine Shop HVAC Testing
14.2.9.4.20 Radwaste Building HVAC System
14.2.9.4.21 Main, Unit Auxiliary and Reserve Transformer Test

For each of the above preoperational test abstracts, the NRC staff reviewed the test description, purpose, prerequisites, general test acceptance criteria, and test methods using the methodology described in Section 14.2.1.2 of this report. In comparing the AP1000 preoperational test program to the preoperational testing recommended in RG 1.68, Appendix A, Section 1, "Preoperational Testing," the staff identified several areas where it required additional information to complete its review. Descriptions of the specific issues and their resolution follow:

- Containment Valve Closure Time Testing

  In RAI 261.001, the staff noted that RG 1.68, Appendix A, "Initial Test Programs," Section 1.i, "Primary and Secondary Containment," recommends the performance of containment isolation valve closure timing tests during preoperational testing. However, the staff was unable to locate a preoperational test abstract in DCD Tier 2, Section 14.2.9.1, that described this testing. In its October 1, 2002, response to this RAI, the applicant stated that DCD Tier 2, Section 14.2.9.1.10, "Containment Isolation and Leak Rate Testing," includes verification of proper operation of the safety-related containment isolation valves listed in DCD Tier 2, Table 6.2.3-1 by the performance of baseline inservice tests, as specified in DCD Tier 2, Section 3.9.6. The applicant stated that the baseline inservice tests include stroke time measurement. The staff determined that containment isolation valve stroke time measurements, as described in DCD Tier 2, Sections 14.2.9.1.10 and 3.9.6.2.2, meet the intent of RG 1.68 and are, therefore, adequate.

- Instrumentation and Control System Tests

  In RAI 261.002, the staff noted that RG 1.68, Appendix A, Section 1.j, "Instrumentation and Control Systems," recommends testing associated with (1) the failed fuel detection system, (2) the hotwell level control system, (3) instruments used to detect external and internal flooding conditions that could result from such sources as fluid system piping failures, and (4) instruments, such as the reactor vessel water level monitors, that can be used to track the course of postulated accidents. In reviewing the AP1000 preoperational test program, the staff was unable to locate information pertaining to these tests. In an October 1, 2002, response to RAI 261.002, the applicant provided additional information related to these tests. The staff's evaluation of this additional information as related to each of the above items is provided below:

  (1) Failed Fuel Detection System

  The NRC staff noted that AP1000 DCD Tier 2, Section 4.2.4.3, "Letdown Radiation Monitoring," indicated that the chemical and volume control system letdown radiation monitor may be used to indicate a breach in the fuel rod pressure boundary. However, the staff was unable to locate a preoperational test abstract that described testing of this function. In its October 1, 2002, response the applicant stated that the letdown radiation monitor was within the scope of the radiation monitoring system testing described in DCD Tier 2, Section 14.2.9.2.18. Upon further review of this RAI response, the staff determined that the AP1000 design does not have a letdown radiation monitor. In a February 13, 2003, revision to its initial RAI response, the applicant stated that it revised DCD Tier 2, Section 4.2.4.3, to state that grab samples are used for letdown radiation monitoring. Because the AP1000 design does not use a failed fuel detector, the staff determined that the failed fuel detection system testing recommendations in RG 1.68 did not apply to the AP1000.

(2) Hotwell Level Control System

In reviewing DCD Tier 2, Section 14.2.9.4.1, "Condensate System Testing," the staff was unable to locate specific testing provisions for the hotwell level control system. In its October 1, 2002, RAI response, the applicant stated that the condensate hotwell level control system is part of the condensate system controls. The applicant added that proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified in accordance with DCD Tier 2, Section 14.2.9.4.1. On the basis that the hotwell level control system is tested in conjunction with the verification of proper calibration and operation of condensate system controls, the staff has determined that the AP1000 preoperational test program satisfies RG 1.68 and therefore is adequate.

(3) Flood Detection Instrumentation

Based on information contained in DCD Tier 2, Section 14.3, "Certified Design Material," and Table 14.3.5, "Flood Protection," the staff determined that the AP1000 design included a flood protection feature. However, the staff was unable to locate test standards for flood detection instrumentation in DCD Tier 2, Section 14.2. In its October 1, 2002, RAI response, the applicant stated that although flood protection is a design feature for the AP1000, no instruments are included for detecting floods (other than those for containment flooding which is covered in other initial test program sections). On the basis that the AP1000 design does not include specific flood detection instrumentation, the staff concluded that the flood detection instrumentation testing recommendations of RG 1.68 are not applicable to the AP1000 design certification. Section 3.4.1.2 of this report discusses internal flooding.

(4) Postaccident Monitoring Instrumentation

In comparing the AP600 preoperational test program to the proposed AP1000 test program, the staff noted that the AP1000 test program does not include a specific test abstract related to postaccident monitoring instrumentation. DCD Tier 2, Table 7.5-1, "Safety-Related Display Information," lists the instruments used for postaccident monitoring. The staff located the test standards for many of the postaccident instruments listed in DCD Tier 2, Table 7.5-1 within test abstracts for other systems, including DCD Tier 2, Section 14.2.9.1.1, "Reactor Coolant System Testing"; DCD Tier 2, Section 14.2.9.1.12, "Protection and Safety Monitoring System Testing"; and DCD Tier 2, Section 14.2.9.2.20, "Primary Sampling System Tests." However, the staff could not locate test standards for the reactor vessel level indication system (RVLIS) and humidity monitors, two of the postaccident monitoring instruments listed in RG 1.68, Appendix A, Item 1.j.22.

In an October 1, 2002, RAI response, the applicant indicated that under the criteria in DCD Tier 2, Section 7.5, "Post Accident Monitoring System," the AP1000 does not need the RVLIS or the humidity monitors for postaccident monitoring functions and therefore they are not included in Table 7.5-1. However, the applicant stated that reactor vessel level indication testing is addressed under the hot leg instrumentation initial testing described in DCD Tier 2, Section 14.2.9.1.1, "Reactor Coolant System Testing." With regard to humidity monitors, the applicant stated that the containment humidity monitors are part of the containment leak rate test system and are installed inside containment for Type A testing. On the basis that the reactor vessel level instrument and the humidity monitors are not classified as postaccident monitoring instruments, the staff concludes that the testing recommendations of RG 1.68 for RVLIS and humidity monitors are not applicable to the AP1000.

- Radiation Protection System Tests

RG 1.68, Appendix A, Item 1.k, "Radiation Protection Systems," states that appropriate tests should be conducted to demonstrate proper operation of systems and components used to provide for personal protection or to control or limit the release of radioactivity. Specifically, RG 1.68 states that testing of high-efficiency particulate air (HEPA) filter and charcoal adsorber efficiency should include in-place leak testing and verification of redundancy and electrical independence consistent with the provisions of RG 1.52. The staff noted that DCD Tier 2, Section 9.4.1.2.2, "Component Description," references use of RG 1.140, rather than RG 1.52 for testing of HEPA filters and charcoal adsorbers. In RAI 261.003, the staff requested the applicant to provide additional information to explain its use of RG 1.140 rather than RG 1.52 for accomplishing this testing.

In its October 1, 2002, response to this RAI, the applicant stated that the nuclear island (NI) nonradioactive ventilation system (described in DCD Tier 2, Section 9.4.1, "Nuclear Island Nonradioactive Ventilation System,") and the containment air filtration system (described in DCD Tier 2, Section 9.4.7, "Containment Air Filtration System,") use HEPA filters and charcoal adsorbers. The applicant stated that DCD Tier 2, Sections 14.2.9.2.10 and 14.2.9.4.12, respectively, describe the initial test program associated with these systems. Because this testing is being performed during the preoperational test phase when there is no fuel in the reactor vessel, the staff determined that RG 1.140 provides the appropriate guidance for testing non-safety-related HEPA filters and charcoal absorbers. The staff determined that because the NI nonradioactive ventilation and containment air filtration system are non-safety-related systems, RG 1.140 is the appropriate guidance for this testing.

- Fuel Storage and Handling System Tests

  RG 1.68, Appendix A, Section 1.m, "Fuel Storage and Handling Systems," recommends that the preoperational test program include operability and leak tests of sectionalizing devices and drains and leak tests of gaskets or bellows in the refueling canal and fuel storage pool. The staff noted that DCD Tier 2, Section 14.2.9.1.15, "Fuel Handling and Reactor Component Servicing Equipment Test," does not include preoperational leak tests of gaskets or bellows in the refueling canal and fuel storage pool. In RAI 261.004, the staff requested the applicant to provide additional information related to the performance of this testing. In its October 1, 2002, response to this RAI, the applicant stated that the critical gasket in the design, the double-gasketed blind flange at the refueling canal end, is tested in accordance with DCD Tier 2, Section 14.2.9.1.10, "Containment Isolation and Leak Rate Testing." In DCD Tier 2, Section 14.2.9.2.7, "Spent Fuel Pool Cooling System Testing," the applicant added Item (g) to state that "the gates, drains, bellows, and gaskets in the refueling canal and fuel storage pool are checked for unacceptable leakage." Based on this response, the staff concluded that the preoperational test program adequately addresses operability and leak tests, satisfies RG 1.68, Appendix A, Section 1.m, and is, therefore, acceptable.

- Irradiated Fuel Pool and Building Ventilation System Tests

  RG 1.68, Appendix A, Item 1.m, recommends that preoperational testing of the irradiated fuel pool or building ventilation system be conducted. The staff was unable to locate test abstracts related to this system in DCD Tier 2, Section 14.2.9.1.15. In RAI 261.008, the staff requested that the applicant provide more information related to this testing. In its October 1, 2002, RAI response, the applicant stated that DCD Tier 2, Section 14.2.9.2.11, "Radiologically Controlled Area Ventilation System," describes performance testing during a series of individual component and integrated system tests to verify that the system performs its defense-in-depth function. The staff determined that the radiologically controlled area ventilation system performs the functions of the fuel pool or building ventilation system referenced by RG 1.68, Appendix A, Item 1.m. In its RAI response, the applicant also stated that DCD Tier 2, Section 9.4.3.4, identifies that a system air balance test and adjustment to design conditions will be conducted in the course of the plant's preoperational test program. Accordingly, the staff concludes that the testing described by the applicant adequately addresses irradiated fuel pool or building ventilation system testing, satisfies RG 1.68, Appendix A, Item 1.m, and is, therefore, acceptable.

In performing the design-specific testing review, the staff identified several areas where it required additional information to support its technical review of preoperational test abstracts. Discussions of these areas, identified as Open Items 14.2-1.a through 14.2-1.l, 14.2-1.z, 14.2-1.aa, and 14.2-1.bb, follow:

- In Open Items 14.2-1.a through 14.2-1.l, the staff requested additional information to support the review of preoperational testing abstracts. These open items addressed the following items: clarification of test parameters and acceptance criteria for testing of the passive containment cooling system (Open Items 14.2-1.a through 14.2-1.e), clarification of test methods for steam generator loose parts monitoring (Open Item 14.2-1.f), provisions for the use of test switches for blocking unwanted device actuations during protection and safety monitoring system testing (Open Item 14.2-1.g), clarification of plant communication system testing acceptance criteria to address maximum potential noise levels (Open Item 14.2-1.h), resolution of test parameter and acceptance criteria discrepancies for ventilation system testing (Open Item 14.2-1.i), clarification of the functions to be tested during reactor coolant system testing (Open Item 14.2-1.j), acceptance criteria for passive core cooling system testing (Open Item 14.2-1.k), and clarification of normal residual heat removal testing (Open Item 14.2-1.l). In a letter dated August 26, 2003, the applicant responded to these open items and provided information to (1) clarify inconsistent test parameters, performance criteria, and acceptance criteria for plant equipment, (2) provide additional test methods for plant equipment (i.e., a special monitoring system with steam generator acoustic monitors for loose parts monitoring, testing communication equipment under maximum noise levels, test switches or racking out circuit breakers to block device actuation/operation), (3) add information to test abstracts to clarify performance and acceptance criteria, and (4) correct inconsistencies between design value numbers in DCD Tier 2, Table 14.3-2, "Design-Basis Accident Analysis," and DCD Tier 2, Table 6.2.2-1, "Passive Containment Cooling System Performance Parameters." The staff verified that the revisions to the DCD were consistent with this additional information. Based on this information, Open Items 14.2-1.a through 14.2-1.l are resolved.

- In Open Item 14.2-1.z, the staff requested additional information to resolve omissions and inconsistencies in preoperational test abstract 14.2.9.1.9, "Reactor Vessel Internals Vibration Testing." In a letter dated August 26, 2003, the applicant responded to Open Item 14.2-1.z and provided information on the number of transducers to be used during the testing, described transducer locations and their direction of sensitivity, and resolved inconsistencies between test abstract 14.2.9.1.9 and WCAP-15949-P, "AP1000 Reactor Internals Flow-Inducted Vibration Assessment Program." The staff verified that the revisions to the DCD were consistent with this additional information. Based on this information, Open Item 14.2-1.z is resolved.

- The staff reviewed preoperational test abstract 14.2.9.1.7, "Expansion, Vibration, and Dynamic Effects Testing," which described preoperational testing for safety-related, high-energy piping systems and components. Although the DCD Tier 2 material included an adequate test abstract description, it did not reference any applicable Tier 1 material (i.e., ITAAC), nor does it appear that any ITAAC have been written to provide documentation of the test measurements for thermal expansion and vibration amplitudes, and their comparison to allowable values. The staff requested the applicant to update the AP1000 DCD Tier 1 material by providing appropriate ITAAC information for those systems, or portions thereof, described in test abstract 14.2.9.1.7, that will be subject to preoperational, hot functional testing prior to fuel load. This issue was Open Item 14.2-1.aa.

In response to Open Item 14.2-1.aa, in a letter dated September 8, 2003, the applicant stated that the purpose of the testing is to verify that the ASME Class 1, 2, and 3 piping systems are designed consistent with the piping stress analyses that is performed to demonstrate conformance with the ASME Code. The applicant noted that the Tier 1 material includes suitable ITAAC to demonstrate that the design and construction of the as-built piping systems designated as ASME Code Section III is in accordance with ASME Code Section III requirements. Further, the applicant noted that every Tier 1 system description that contains ASME Code piping also includes this design commitment. Therefore, the ITAAC require that an ASME Code Section III design report exists for the as-built piping. However, the applicant did not include an additional ITAAC specifically for the expansion, vibration and dynamic effects testing in the AP1000 DCD. Additionally, the applicant stated that, in accordance with accepted practice, the Tier 2 material does not reference Tier 1 material, except as discussed in DCD Tier 2, Section 14.3.

The staff determined that the applicant's initial response to Open Item 14.2-1.aa was incomplete because the referenced ITAAC did not appear to address all necessary testing. Specifically, while the response correctly stated the purpose of the expansion, vibration, and dynamic effects testing, the ITAAC referenced in the response does not fully accomplish this testing. The referenced ITAAC does not consider the potential effects of unanticipated constraint from other installed SSCs on an individual piping system when considered in the context of the as-built condition of the entire plant. The ITAAC referenced in the response proposes reconciling the as-built condition of the piping system itself with the requirements of the ASME Code design report. However, this design reconciliation alone, while satisfying design requirements, does not verify that the piping will have sufficient clearance with all other installed equipment to allow analytically predicted movement during transient events.

In a letter to the NRC staff dated October 21, 2003, the applicant responded to the staff's comments noted above regarding Open Item 14.2-1.aa. The staff's concern with the previous applicant response was that the acceptance criteria for the ITAAC referenced in the response did not appear to explicitly address preoperational testing activities, including the piping expansion, vibration, and dynamic effects testing outlined in DCD Tier 2, Section 14.2.9.1.7. The acceptance criteria for the ITAAC referenced in the applicant's response (Revision 1) state that ASME Code Section III design reports exist for the as-built piping classified as ASME Code Section III. It was unclear whether the reconciliation of the as-built condition of the piping with the ASME III piping design reports included preoperational testing results for the respective piping systems and components.

The applicant's revised response specifically identifies preoperational testing, including piping expansion, vibration, and dynamic effects testing, as information which the as-built reconciliation of piping systems designed and constructed to ASME Code Section III requirements must address. The applicant committed to revising DCD Tier 2, Section 3.6.2.5, "Evaluation of Dynamic Effects of Pipe Ruptures," to identify reconciliation of ASME Code Section III piping systems as a COL applicant activity in the context of the verification of the final pipe break hazard analysis report. The proposed revision of the final paragraph of DCD Tier 2, Section 3.6.2.5 adds preoperational testing to the list of activities which must be evaluated in the as-built reconciliation of ASME Code Section III piping. In its review of this proposed DCD revision, the staff concluded that it is an acceptable resolution of the original concern because it provides an explicit reference to preoperational testing as a part of the as-built reconciliation of the ASME Code Section III piping design reports.

The staff also requested the applicant to provide a similar revision to DCD Tier 2, Section 3.9.3. This additional revision would serve to define more completely the as-built reconciliation for ASME Code, Section III, Class 1, 2, and 3 piping and components as a COL applicant activity. This additional revision would also provide consistency among DCD Tier 2, Sections 3.6.2.5, 3.6.4.1, "Pipe Break Hazard Analysis," 3.9.3, and 3.9.8.2, "Design Specifications and Reports," which discuss the types of activities to be specifically included in as-built reconciliation efforts.

The applicant's revised response dated November 7, 2003, revised the DCD to add references which provided a link between the piping expansion, vibration, and dynamic effects testing outlined in DCD Tier 2, Section 14.2.9.1.7 and existing Tier 1 ITAAC acceptance criteria. The staff finds the revised response and the DCD revision to be acceptable. Therefore, Open Item 14.2-1.aa is resolved.

- Although the NRC staff found that test abstract 14.2.9.1.8, "Control Rod Drive System," is adequate, the applicant made no reference to any applicable Tier 1 material (ITAAC), nor does it appear that any ITAAC have been written to provide documentation of these tests, including a comparison to specified acceptance criteria. Because of the safety significance of these components, the DCD Tier 1 material should include the corresponding tests of the as-built configuration and the comparison of test results to applicable acceptance criteria. The staff requested the applicant to update the DCD Tier 1 material by providing appropriate ITAAC information for those components described in DCD Tier 2, Section 14.2.9.1.8 that will be subject to preoperational, hot functional testing prior to fuel load. This was Open Item 14.2-1.bb.

  In response to Open Item 14.2-1.bb, in a letter dated September 8, 2003, the applicant stated that DCD Tier 1, Section 2.1.3, "Reactor System," included testing of the control rod drive system. This section provides the Tier 1 design commitments and associated ITAAC for the control rod drive mechanisms. Further, the applicant stated that in accordance with accepted practice, the Tier 2 material does not reference Tier 1 material, except as discussed in DCD Tier 2, Section 14.3. The staff finds this response to be acceptable; therefore, Open Item 14.2-1.bb is resolved.

The staff finds that the preoperational test abstracts in DCD Tier 2, Section 14.2.9 adequately address testing scope, general test methods, performance criteria, and acceptance criteria. The staff concludes that the AP1000 preoperational test program meets the guidance in SRP Section 14.2 and RG 1.68 and is sufficient to demonstrate that the SSCs important to safety will meet their performance and acceptance criteria.

14.2.10 Initial Fuel Loading, Initial Criticality, Startup, and Power Ascension Tests

RG 1.68 and SRP Section 14.2 provide general guidance on the conduct of the initial test program after the completion of preoperational testing. Following verification of SSC functional capability during preoperational testing, the initial test program transitions to initial fuel loading, precritical testing, initial startup, low-power testing, and power ascension testing. Initial fuel loading and precritical tests ensure safe initial core loading and maintain sufficient shutdown margin. After the core is loaded, sufficient tests and checks should be performed to ensure that the facility is in a final state of readiness to achieve criticality and perform low-power testing. The initial approach should be conducted in a deliberate and orderly manner consistent with methods that will be used for subsequent startups. As described in RG 1.68, after the initial reactor startup, low-power testing is conducted to (1) confirm the design, (2) validate analytical models and verify correctness of conservatism of assumptions used in the safety analysis to the extent practical, and (3) confirm the operability of plant systems and design features that could not be completely tested during the preoperational test phase because of the lack of an adequate heat source for the reactor coolant system and the main steam system. Finally, power ascension testing is conducted to demonstrate that the facility can be operated in accordance with design during normal steady-state conditions, and, to the extent practical, during and following anticipated transients. The SRP Section 14.2 acceptance criteria for startup and power ascension testing include verification that test abstracts include objectives, prerequisites, test methods, and acceptance criteria to establish the functional adequacy of SSCs and design features.

The NRC staff reviewed the following startup and power ascension AP1000 test abstracts:

<u>Initial Fuel Loading Tests</u>

14.2.10.1.1 Fuel Loading Prerequisites and Periodic Checks
14.2.10.1.2 Reactor System Sampling for Fuel Loading
14.2.10.1.3 Fuel Loading Instrumentation and Neutron Source Requirements
14.2.10.1.4 Inverse Count Rate Ratio Monitoring for Fuel Loading
14.2.10.1.5 Initial Fuel Loading
14.2.10.1.6 Post-Fuel Loading Precritical Sequence
14.2.10.1.7 Incore Instrumentation System Precritical Verification
14.2.10.1.8 Resistance Temperature Detector—Incore Thermocouple Cross Calibration
14.2.10.1.9 Nuclear Instrumentation System Precritical Verifications
14.2.10.1.10 Setpoint Precritical Verification
14.2.10.1.11 Rod Control System
14.2.10.1.12 Rod Position Indication System
14.2.10.1.13 Control Rod Drive Mechanism
14.2.10.1.14 Rod Drop Time Measurements
14.2.10.1.15 Rapid Power Reduction System
14.2.10.1.16 Process Instrumentation Alignment
14.2.10.1.17 Reactor Coolant System Flow Measurement
14.2.10.1.18 Reactor Coolant System Flow Coastdown
14.2.10.1.19 Pressurizer Spray Capability and Continuous Spray Flow Verification

Verification Programs

14.2.10.1.20 Feedwater Valve Stroke Test

Initial Criticality Tests

14.2.10.2.1 Initial Criticality and Low-Power Test Sequence
14.2.10.2.2 Initial Criticality
14.2.10.2.3 Nuclear Instrumentation System Verification During Initial Criticality
14.2.10.2.4 Post-Criticality Reactivity Computer Checkout

Low-Power Testing

14.2.10.3.1 Low-Power Test Sequence
14.2.10.3.2 Determination of Physics Testing Range
14.2.10.3.3 Boron Endpoint Determination
14.2.10.3.4 Isothermal Temperature Coefficient Measurement
14.2.10.3.5 Bank Worth Measurement
14.2.10.3.6 Natural Circulation (First Plant Only)
14.2.10.3.7 Passive Residual Heat Removal Heat Exchanger

Power Ascension Tests

14.2.10.4.1 Test Sequence
14.2.10.4.2 Incore Instrumentation System
14.2.10.4.3 Nuclear Instrumentation System
14.2.10.4.4 Setpoint Verification
14.2.10.4.5 Startup Adjustments of Reactor Coolant System
14.2.10.4.6 Rod Cluster Control Assembly Out-of-Bank Measurements
14.2.10.4.7 Axial Flux Difference Instrumentation Calibration
14.2.10.4.8 Primary and Secondary Chemistry
14.2.10.4.9 Process Measurement Accuracy Verification
14.2.10.4.10 Process Instrumentation Alignment at Power Conditions
14.2.10.4.11 Reactor Coolant System Flow Measurement at Power Conditions
14.2.10.4.12 Steam Dump Control System
14.2.10.4.13 Steam Generator Level Control System
14.2.10.4.14 Radiation and Effluent Monitoring System
14.2.10.4.15 Ventilation Capability
14.2.10.4.16 Biological Shield Survey
14.2.10.4.17 Thermal Power Measurement and Statepoint Data Collection
14.2.10.4.18 Dynamic Response
14.2.10.4.19 Reactor Power Control System
14.2.10.4.20 Load Swing Test
14.2.10.4.21 100 Percent Load Rejection
14.2.10.4.22 Load Following Demonstration (First Plant Only)
14.2.10.4.23 Hot Full Power Boron Endpoint
14.2.10.4.24 Plant Trip from 100 Percent Power
14.2.10.4.25 Thermal Expansion

14.2.10.4.26 Loss of Offsite Power
14.2.10.4.27 Feedwater Heater Loss and Out of Service Test
14.2.10.4.28 Remote Shutdown Workstation

For each of the above test abstracts, the staff reviewed the test description, purpose, prerequisites, general test acceptance criteria, and test methods using the methodology described in Section 14.2.1.2 of this report. The following sections describe the staff's review of the initial fuel loading tests, initial criticality tests, low-power testing, and power ascension testing.

14.2.10.1 Initial Fuel Loading Tests

For initial fuel loading, RG 1.68, Appendix A, Section 2, "Initial Fuel Loading and Precritical Tests," specifies safety measures to preclude inadvertent reactor criticality during initial fuel loading. These measures include control and monitoring of fuel loading activities, measurement and prediction of core physics parameters, and operability of reactivity control systems. Following core load, tests are performed at hot conditions to bring the plant to a final state of readiness prior to initial criticality. Initial fuel loading testing, described in DCD Tier 2, Section 14.2.10.1, "Initial Fuel Loading and Precritical Tests," is performed after completion of preoperational testing, but prior to initial criticality. These tests include those performed prior to the core load to verify the readiness of the plant for core loading, the loading of the core, and the tests performed under hot conditions after the core has been loaded, but prior to initial criticality. These tests verify that the systems necessary to monitor the fuel loading process are operational and that the core loading is conducted properly.

In performing the design-specific testing review, the staff identified several areas where it required additional information to support its technical review of the initial fuel loading test abstracts. These were identified as Open Items 14.2-1.m through 14.2-1.s. Specifically, the staff required additional information on test performance methodology and acceptance criteria related to (1) operator actions for deviations in RCS boron concentrations (Open Item 14.2-1.m), (2) the expected correct response of neutron monitoring instrumentation (Open Item 14.2-1.n), (3) criteria and guidance for suspension of fuel loading activities (Open Items 14.2-1.o and 14.2-1.p), (4) the sequencing of instrumentation testing to minimize reliance on untested equipment (Open Item 14.2-1.q), (5) operator guidance for test result deviations during rod drop time testing (Open Item 14.2-1.r), and (6) acceptance criteria for pressurizer spray testing (Open Item 14.2-1.s).

By letter dated August 26, 2003, the applicant responded to these open items and provided additional information on initial fuel loading tests to clarify the testing scope, test methods, performance criteria, and acceptance criteria to address Open Items 14.2-1.m through 14.2-1.s. The additional information includes performance and acceptance criteria for boron concentrations, correct response of neutron monitoring instrumentation, neutron count rate during "stop loading" or "unload" actions, core moderator chemistry (particularly boron concentration), and core loading procedures for fuel and control rod assemblies in test abstracts 14.2.10.1.2, 14.2.10.1.3, 14.2.10.1.4, and 14.2.10.1.5. The additional information also included final calibration of source range instrumentation and verification of alarms and protective functions for source and intermediate range monitors to support precritical tests in test abstract 14.2.10.1.6, as well as the appropriate pressure control system design specifications documentation for the pressurizer spray valves in test abstract 14.2.10.1.19. The staff finds that the applicant added sufficient information in its revision of DCD Tier 2, Section 14.2.10.1. Therefore, Open Items 14.2-1.m through 14.2-1.s are resolved.

The staff also concludes that the testing scope, general test methods, and performance and acceptance criteria are sufficient to test the SSCs important to safety during the initial fuel load test phase. The staff finds that all AP1000 test programs adequately address the initial fuel loading and precritical testing and meet the associated guidance in SRP Section 14.2 and RG 1.68.

14.2.10.2 Initial Criticality Tests

RG 1.68, Appendix A, Section 3, "Initial Criticality," provides recommendations for conducting initial criticality testing, including control of core reactivity and monitoring of core performance. In DCD Tier 2, Section 14.2.10.2, "Initial Criticality Tests," the applicant stated that following completion of the core loading and precriticality testing, the plant is brought to initial criticality, according to test procedures in Section 14.2.10.2.1, "Initial Criticality Test Sequence."

The staff compared the AP1000 initial criticality test program to the initial criticality testing provisions of RG 1.68 and noted four areas where the information contained in the AP1000 initial criticality test program differed from the guidance contained in RG 1.68. In RAI 261.005, the staff requested the applicant to provide additional information relating to these four areas of initial criticality testing. A discussion of the resolution of these four areas follows:

- The NRC staff identified several precautions, prerequisites, and measures described in RG 1.68, Appendix A, Section 3, that the AP1000 initial criticality test abstracts did not address. The precautions, prerequisites, and measures not covered by the AP1000 test abstracts included (1) operational readiness of the reactor protection system and emergency shutdown systems, (2) minimum neutron count rate on nuclear instruments prior to commencement of startup, (3) movement of control rods during the initial startup and control rod insertion limits, (4) reactivity addition sequence and minimum reactor period after criticality is achieved, (5) compliance with TS requirements, and (6) setting of high-flux scram trips to their lowest value (approximately 5–20 percent of full power).

  In its November 15, 2002, RAI response, the applicant noted that the AP1000 test abstracts provide an overview of the tests to be performed on the plant. The applicant noted that the scope of the DCD does not include detailed test specifications or procedures, however, the COL applicant will submit them to the NRC for review, as identified in DCD Tier 2, Section 14.4.2. As described in Section 14.2.3 of this report, the staff finds it acceptable to defer responsibility for the development of detailed preoperational and startup test specifications and procedures to the COL applicant. This is COL Action Item 14.4-2.

- The title of test abstract 14.2.10.2.1, "Initial Criticality and Low-Power Test Sequence," appeared to be redundant to the test abstract described in DCD Tier 2, Section 14.2.10.3.1, "Low-Power Test Sequence." In its November 15, 2002, RAI response, the applicant stated that it will revise the title of DCD Tier 2, Section 14.2.10.2.1, to read "Initial Criticality Test Sequence." The staff determined that the test abstracts provided in Sections 14.2.10.2.1 and 14.2.10.3.1 are not redundant and that the revision to the title of DCD Tier 2, Section 14.2.10.2.1, eliminated ambiguity. The applicant revised the test abstract in DCD Tier 2, Section 14.2.10.2.1 to better reflect the scope of testing. Therefore, the staff considers this issue to be resolved.

- The guidance contained in test abstract 14.2.10.2.2, "Initial Criticality," regarding control rod movement and boron dilution rate, appeared to be inconsistent with certain provisions of RG 1.68. Specifically, test abstract 14.2.10.2.2 states, "as criticality is approached, slow or stop dilution rate to allow criticality to occur during mixing or by rod withdrawal." However, the staff noted that RG 1.68, Appendix A, Section 3, states that for reactors that will achieve initial criticality by boron dilution, control rods should be withdrawn before dilution begins. Because the wording in test abstract 14.2.10.2.2 indicates that rod withdrawal may occur after a dilution to criticality has begun, the staff questioned the consistency of this test abstract with RG 1.68.

  In its November 15, 2002, RAI response, the applicant noted that the test method section of test abstract 14.2.10.2.2 specified a controlled rod withdrawal using the same rod withdrawal sequence as that employed for normal plant startup prior to dilution of the reactor coolant system boron concentration. Further, the applicant noted that after the rods are withdrawn, they may be slightly inserted for control purposes. Therefore, to clarify the intent of the test abstract, the applicant revised the test abstract to read, "as criticality is approached, slow or stop dilution rate to allow criticality to occur during mixing or withdrawal of rods that have been slightly inserted for control." The staff has determined that a slight withdrawal of control rods that may have been inserted for control purposes would not represent a significant addition of reactivity due to rod withdrawal and is, therefore, acceptable after reactor coolant boron dilution has commenced. Thus, the staff concludes that this test abstract meets the RG 1.68 precautions.

- The staff noted that the title to test abstract 14.2.10.2.3, "Nuclear Instrumentation System Verification During Initial Criticality," does not reflect the performance of the nuclear instrument system verification prior to and during initial criticality. In its November 15, 2002, RAI response, the applicant stated that it revised the title of test abstract 14.2.10.2.3 to read, "Nuclear Instrument System Verification." The staff concludes that the revised DCD adequately addresses its comments and is therefore acceptable.

In Open Item 14.2-1.t, the staff determined that the applicant had not specified in the initial criticality test abstract that the plant operators take appropriate action if the measured reactivity and the corresponding values indicated by the plant computer deviated from the tolerance limits. The staff requested that the applicant supplement the appropriate test abstract to verify proper operation of associated alarms and protective functions for source range and intermediate range monitors. On October 30, 2003, the applicant stated that it will revise the prerequisites of DCD Tier 2, Section 14.2.10.2.4, "Post-Critical Reactor Computer Checkout," to require completion of DCD Tier 2, Section 14.2.10.2.3 prior to the initiation of this test. Specifically, the applicant committed to add the following information to the prerequisites of DCD Tier 2, Section 14.2.10.2.4:

> The systems, structures, and components required by Technical Specifications shall be operable as required for the specified plant operational mode prior to initiation of precritical, low power physics, and power ascension testing. Verification of proper operation of source-range and intermediate-range excore nuclear instrumentation and associated alarms and protective functions in Startup Test 14.2.10.2.3 shall be completed prior to initiation of this startup test.

In addition, the applicant committed to add the following statement to the performance criterion of DCD Tier 2, Section 14.2.10.2.4:

> Adjustment and re-calibration or repair of the reactivity computer may be required if the deviation between the two independent sources of reactivity is not within design tolerances.

The applicant revised DCD Tier 2, Section 14.2.10.2.4 to add the information to the test abstract stated above. The staff reviewed the changes to the DCD and confirmed that they were consistent with RG 1.68 and SRP Section 14.2. Therefore, Open Item 14.2-1.t is resolved.

The staff found that the initial criticality test abstracts met the guidance in SRP Section 14.2 and RG 1.68 and are, therefore, acceptable. Thus, the staff concludes that initial criticality testing prerequisites, precautions, general test methods, and performance and acceptance criteria are sufficient to test the SSCs important to safety during the initial criticality phase of the initial test program.

14.2.10.3 <u>Low-Power Tests</u>

The low-power test program should confirm the design, and to the extent practical, validate the analytical models and verify the correctness or conservatism of assumptions used in the safety analysis report. Additionally, the low-power test program should also confirm the operability of plant systems and design features that could not be adequately tested during the preoperational test phase because of a lack of an adequate heat source for the reactor coolant system. In DCD Tier 2, Section 14.2.10.3, "Low-Power Tests," for the AP1000 design, the applicant stated that following successful completion of the initial criticality tests, low-power tests are conducted, typically at power levels less than 5 percent, to measure physics characteristics of the reactor system and to verify operability of the plant systems at low-power levels. Based on a review of the low-power test abstracts, the staff had concerns in two areas and issued RAIs 261.006 and 261.009 to obtain additional information to complete the review of the proposed AP1000 low-power test program. A discussion of the resolution of these two staff concerns follows:

- The staff was unable to locate 20 low-power tests that were listed in RG 1.68 as applicable to PWRs in the AP1000 low-power test program. In RAI 261.006a, the staff requested the applicant to provide additional information regarding the verification of the functions addressed by the low-power tests recommended in RG 1.68. In its November 15, 2002, response to this RAI, the applicant provided a table identifying how the AP1000 test program addressed each of the 20 RG 1.68 low-power tests. The staff reviewed the table provided in the applicant's response and determined that the applicant's test program included the necessary low-power tests recommended in RG 1.68. Therefore, the staff concludes that the AP1000 test program adequately addresses all applicable low-power tests recommended in RG 1.68.

- The staff noted that the power ascension test abstract described in DCD Tier 2, Section 14.2.10.4.3, "Nuclear Instrumentation System," includes a demonstration of instrumentation overlap between the source range and intermediate range nuclear instruments. However, the staff determined that overlap between the source and intermediate range occurs well below the reactor power level associated with power ascension testing. Therefore, in RAI 261.006b, the staff requested that the applicant either justify performing the source and intermediate range overlap testing during the power ascension test phase, or conduct this testing during low-power testing. In its November 15, 2002, RAI response, the applicant deleted the overlap from test abstract 14.2.10.4.3 and stated that the initial criticality test abstract 14.2.10.2.3, "Nuclear Instrumentation System Verification," verifies the overlap between the source range and intermediate range neutron monitors. Because both the source range and intermediate range nuclear instruments can monitor the low-core power level during the initial criticality test phase, the staff concludes that the initial criticality test phase is appropriate for demonstrating the overlap between the source and intermediate range nuclear instruments.

- RG 1.68, Appendix A, Item 4.c recommends performance of pseudo-rod ejection testing to verify calculation models and accident analysis assumptions during low-power testing. The staff could not locate an AP1000 low-power test abstract that describes this testing. In RAI 261.009, the staff requested that the applicant provide additional information regarding the performance of pseudo-rod ejection testing for the AP1000 design. In its November 15, 2002, RAI response, the applicant stated that sufficient test data have been obtained from previous plant startups, and that licensees of new plants only need to confirm calculational models. The applicant also provided several licensing precedents associated with this position.

  The staff determined that the applicant's November 15, 2002, response to RAI 261.009 lacked sufficient information regarding the applicant's decision not to perform low-power pseudo-rod ejection testing. Therefore, in RAI 261.016, the staff requested that the applicant provide additional information relating to the conduct of pseudo-rod ejection testing during the low-power test phase. This was Open Item 14.2.10-1 in the DSER.

On July 31, 2003, the applicant provided a response to Open Item 14.2.10-1, stating that the pseudo-rod ejection test is performed in the 30–50 percent power range. The test is performed in the first unit only as part of the rod cluster control assembly out-of-bank measurement test. This 30–50 percent range is the preferred range in which to perform the test because the range is low enough to validate the calculation tools and accident analyses assumptions. Although the response addressed the staff's concern about the power level at which the pseudo-rod ejection test would be performed during power ascension testing, the staff determined that the applicant's July 31, 2003, response failed to adequately address why it did not perform pseudo-rod ejection testing during the low-power test phase. The applicant submitted a revised response to Open Item 14.2.10-1 on October 6, 2003, stating that this testing is not performed at low power (i.e., it is not consistent with RG 1.68, Item 4.c) because the applicant has amassed sufficient data from the low-power operation of currently operating plants to conclude that the Westinghouse nuclear physics codes are established nuclear design tools with validating performance records. Therefore, the applicant deemed the reverification of the calculation models and accident analysis assumptions at low power to be unnecessary. The applicant noted that Westinghouse letter PGD-82-109, "Core Physics Code Validation," dated March 16, 1982, contains the referenced data.

Although the staff concurs that pseudo rod ejection testing at low power is not needed to verify calculation models, the staff concluded that the applicant did not provide an adequate basis for its decision not to perform pseudo-rod ejection testing at low power. Specifically, the staff questioned if this low-power test should be performed to identify potential errors in the fuel loading of the core.

In its November 7, 2003, supplemental response to Open Item 14.2.10.1, the applicant stated that the in-core instrumentation system test performed for each AP1000 plant would detect fuel load errors. The staff determined that test abstract 14.2.10.4.2, "Incore Instrumentation System," includes a test objective to obtain data for in-core thermocouples and flux maps at various power levels during ascension to full power to determine the flux distributions and verify proper core loading and fuel enrichment.

Based on the staff's review of DCD test abstract 14.2.10.4.2, as well as a review of the applicant's response to Open Item 14.2.10-1 dated November 7, 2003, the staff found that the applicant adequately justified its decision not to perform pseudo-rod ejection tests at low power; however, the applicant only partially addressed the identification of fuel load errors or fuel misloadings in the wrong location or orientation. Specifically, test abstract 14.2.10.4.2 requires the verification of proper core loading and fuel enrichment, but it does not address the detection of fuel loading errors or fuel misloadings. The staff determined that the applicant should add test information to DCD Tier 2, test abstract 14.2.10.4.2 about the methods used to detect fuel loading errors or fuel misloadings. This issue was part of Open Item 14.2.10-1 in the DSER.

In its response dated January 13, 2004, the applicant added the following to the test method section of test abstract 14.2.10.4.2:

> Use data from the in-core maps to verify that core power distribution is consistent with design predictions and the limits imposed by the plant TS, including detection of potential fuel load errors, and to calibrate other plant instrumentation. Refer to Technical Specification 3.2, "Power Distribution Limits."

The applicant revised test abstract 14.2.10.4.2, to incorporate the above information. The staff confirmed that this revision is consistent with SRP Section 14.2 and RG 1.68. Therefore, Open Item 14.2.10-1 is resolved.

In performing the design-specific testing review, the staff identified that it required additional information to support its technical review of the low-power test abstracts. These were Open Items 14.2-1.u and 14.2-1.v.

In Open Item 14.2-1.u, the staff requested additional information about test abstract 14.2.10.3.4, "Isothermal Temperature Coefficient Measurement." Specifically, the staff requested the following:

> The "prerequisites" do not include Xenon and Samarium equilibrium. Also, no required action is specified if the moderator temperature coefficient (MTC) is equal to or significantly exceeds the technical specification (TS) value. Please specify the missing prerequisites in the test.

In a letter to the NRC staff dated August 26, 2003, the applicant stated the following:

> The basis for successfully measuring the MTC reactivity effects during low-power physics testing is to stabilize all reactivity contributors so that reactor coolant system temperature changes performed during the test are the only source of core reactivity changes. Therefore, it is inherent in the test requirements that no other significant reactivity variations can occur during MTC testing.
>
> This test is performed by manually varying T_{ave} and determining the amount of reactivity inserted or removed by the temperature change. This test takes a very short time (a few minutes) to complete, so that Xenon and Samarium concentration changes during the duration of this test are not significant. In addition, for an initial core loading, there is no Xenon or Samarium initially in the core. Due to the low power conditions while conducting the physics testing, neither fission product poison concentration changes enough during the testing to significantly impact MTC measures. Therefore, Xenon and Samarium equilibrium conditions are not required as prerequisites for this low-power physics test...
>
> ... For some startup tests, actions are required in the event that performance criteria are not met, or adjustments or repairs to equipment being tested can be performed in the event that performance criteria are not met. However, it is unlikely that corrective actions by either the operators or test personnel actions

could be taken in the event that the Technical Specification MTC limit is not met, if the test is correctly performed. Therefore, no specific operator guidance is provided in the DCD in the unlikely event that rod drop tests are outside of the expected range.

The staff determined that this low-power test does not require xenon and samarium to be in equilibrium as a prerequisite because (1) no xenon and samarium initially exists within the core, and (2) the concentration changes of these elements during the short duration of this test are not significant. Should the MTC exceed the TS limit value, no change to the DCD is needed because the limiting condition for operation (LCO) in TS 3.0.3 specifies the required actions if the MTC exceeds the TS LCO 3.1.4 limit. Therefore, Open Item 14.2-1.u is resolved.

In Open Item 14.2-1.v, the staff questioned the basis for the use of a large-scale test facility to test the PRHR HX function rather than an actual plant test during the low-power test phase. In a revision to low-power test abstract 14.2.10.3.7, "Passive Residual Heat Removal Heat Exchanger (First Plant Only)," the applicant deleted use of the large-scale test facility to test the PRHR HX function. The NRC staff finds this to be acceptable. This issue also relates to the resolution of Open Item 14.2.7-2, discussed in further detail in Section 14.2.7 of this report. Therefore, Open Item 14.2-1.v is resolved.

The staff finds that the low-power tests meet the guidance in SRP Section 14.2 and RG 1.68, and are, therefore, acceptable. Based on a review of the low-power test abstracts, the staff finds that the testing scope, general test methods, and performance and acceptance criteria are sufficient to test applicable functions applicable to safety during the low-power test phase.

14.2.10.4 Power Ascension Tests

As described in RG 1.68, power ascension tests should demonstrate that the facility operates in accordance with its design, both during normal and steady-state conditions and, to the extent practical, during and following anticipated transients. In DCD Tier 2, Section 14.2.10.4, the applicant stated that after low-power testing is completed, testing is performed at specified elevated power levels to demonstrate that the facility can operate in accordance with the design during normal and steady-state operations and, to the extent practical, during and following anticipated transients. During power ascension, tests are performed to obtain operational data and to demonstrate the operational capabilities of the plant.

In comparing the AP1000 power ascension test program to the recommendations of RG 1.68, the staff identified several areas where it required additional information to complete its review. Consequently, the staff issued RAIs 261.007 and 261.010 to obtain this additional information. A discussion of the resolution of these two areas of concern to the staff follows:

- The staff was unable to locate all 40 power ascension tests listed in RG 1.68 as applicable to PWRs in the AP1000 power ascension test program. In RAI 261.007a, the staff requested the applicant to provide additional information regarding the verification of the functions addressed by the RG 1.68 power ascension tests. In its November 15, 2002, response to this RAI, the applicant provided a table identifying how the AP1000 test program addressed each of the 40 power ascension tests listed in RG 1.68. The staff reviewed the table provided in the applicant's response and finds that the applicant's test program includes the necessary power ascension tests recommended in RG 1.68. Therefore, the staff concludes that the AP1000 test program addresses all applicable power ascension tests recommended in RG 1.68.

- Based on a review of power ascension test abstracts, the staff identified specific questions on five power ascension tests. Specifically, the staff requested additional information to evaluate power ascension testing associated with the measurement of power reactivity coefficients, performance of pseudo-rod ejection testing during power ascension testing, demonstration of the capability of the nuclear instrumentation system to detect a rod misalignment, verification of proper operation of the failed fuel detection system, and demonstration of satisfactory plant response following main steam isolation valve closure. In RAI 261.007b, the staff requested the applicant to provide additional information about these five power ascension tests to assist the staff in completings its review of the power ascension test program. The applicant's responses related to each of the five testing areas identified above follow:

(1) RG 1.68, Appendix A, Section 5.a recommends using power ascension testing to verify that the power reactivity coefficients are in accordance with design values. RG 1.68 recommends that reactivity coefficients be measured at 25 percent, 50 percent, 75 percent, and 100 percent of rated reactor power. While the test program provides for such measurements, the staff noted that the testing of the isothermal temperature coefficient measurement, described in DCD Tier 2, Section 14.2.10.3.4, "Isothermal Temperature Coefficient Measurement," occurs only in the low-power test phase. In RAI 261.007b, the staff requested that the applicant provide additional information for testing power reactivity coefficients. In its November 15, 2002, RAI response, the applicant stated that performance of boron endpoint tests occurs at both full power and at no load. The results of the boron endpoint tests will be used to confirm the necessary power coefficient and power defect parameters. Additionally, the staff determined that the applicant includes verification of the power reactivity coefficients during initial criticality, low-power, and power ascension tests. For example, test abstracts 14.2.7.2, "Initial Criticality"; 14.2.10.3.3, "Boron Endpoint Determination"; 14.2.10.3.5, "Bank Worth Measurements"; 14.2.10.4.2, "Incore Instrumentation System"; 14.2.10.4.3, "Nuclear Instrumentation System"; 14.2.10.4.6, "Rod Cluster Control Assembly Out of Bank Measurements"; and 14.2.10.4.23, "Hot Full Power Boron Endpoint," include this verification. Based on this information, the staff determined that appropriate reactivity coefficient testing will occur during initial criticality, low-power, and power ascension tests.

(2) RG 1.68, Appendix A, Item 5.e recommends performance of pseudo-rod ejection testing during the power ascension test phase to validate the rod ejection accident analysis. RG 1.68 further states that this test need not be repeated for facilities using calculation models and designs identical to prototype facilities. The staff could not locate a power ascension test abstract that addressed this

testing. In RAI 261.007b, the staff requested that the applicant provide additional information regarding the performance of this testing. In its November 15, 2002, RAI response, the applicant stated, in part, that this test was part of the rod cluster control assembly out-of-bank measurements described in DCD Tier 2, Section 14.2.10.4.6, "Rod Cluster Control Assembly Out of Bank Measurements." The applicant noted that this test is proposed to be performed on a first-plant-only basis.

The staff determined that the pseudo-rod or rod cluster control assembly ejection tests are performed in test abstract 14.2.10.4.6; therefore, RAI 261.007b, Item 2 is partially resolved. However, the applicant did not initially include test abstract 14.2.10.4.6 in the list of first-plant-only tests cited in DCD Tier 2, Section 14.2.5. The staff determined that the applicant should clarify whether it was intended that this test be performed for every AP1000 plant or whether it was intended to be a first-plant-only test, as described in DCD Tier 2, Section 14.2.5. This was Open Item 14.2.10-2 in the DSER.

In response to Open Item 14.2.10-2, on October 6, 2003, the applicant stated the following:

> This testing is performed on the first plant only, which meets the guidance of RG 1.68, Item 5e—i.e., at greater than 10% power and need not be performed for facilities using calculation models and designs identical to prototype facilities (in the case of AP1000, first unit).

The staff verified that the applicant added test abstract 14.2.10.4.6 to the list of "first-plant-only" tests found in DCD Tier 2, Section 14.2.5. The staff also notes that DCD Tier 2, Section 14.4.6, provides that either the COL applicant or the licensee must perform the tests listed in DCD Tier 2, Subsection 14.2.5, or justify that the results of the first-plant-only tests will apply to subsequent plants. Therefore, the staff will obtain additional information at the COL stage to determine the acceptability of performing this test on a first-plant-only basis. The staff agrees that the pseudo-rod ejection testing, as proposed, meets the guidance of RG 1.68 and SRP Section 14.2. Based on the information provided above, Open Item 14.2.10-2 is resolved.

(3) RG 1.68, Appendix A, Section 5.i recommends that the power ascension test program include in-core and ex-core nuclear instrumentation testing to demonstrate the capability to detect a control rod misalignment equal to or less than the TS limits at 50 percent and 100 percent of rated reactor power. However, as described in DCD Tier 2, Section 14.2.10.4.6, this test is performed between 30–50 percent of rated thermal power. In RAI 261.007b, the staff requested the applicant to provide additional information justifying its decision not to perform this testing at 100 percent of rated thermal power. In its response dated November 15, 2002, the applicant stated that the rod cluster control

assembly out-of-bank measurements test is not performed at full power because it would cause the plant to exceed peak power limits such as departure from nucleate boiling ratio (DNBR). The staff agrees that this test should not be performed at a power level that could cause the plant to exceed thermal limits. However, the staff questioned whether the applicant should include performance of this test at a higher power level than that which was proposed, consistent with RG 1.68. This was Open Item 14.2.10-3 in the DSER.

In response to RAI 261.017 and Open Item 14.2.10-3, the applicant stated the following on May 13, 2003:

> Westinghouse limits the test to the 30 to 50 percent power level in order to assure that plant peaking factor limits are not exceeded. Testing at this range of power levels is sufficient to validate the calculation tools and calibrate instrument responses such that the intent of RG 1.68, Appendix A, Section 5, Item (i) is met.

The staff determined that the applicant adequately justified not performing this test at 100 percent power. The staff also determined that performance of these tests at the 30–50 percent power level will detect rod cluster control assembly misalignments. These tests should be performed before the plant proceeds to a higher power level. The staff determined that this response addressed Open Item 14.2.10-3. The NRC staff found that this test could potentially damage fuel cladding at 100 percent power. Therefore, this exception to RG 1.68 is acceptable and Open Item 14.2.10-3 is resolved.

(4) RG 1.68, Appendix A, Section 5.q recommends verification of the proper operation of failed fuel detection systems be during power ascension testing at 25 percent and 100 percent of rated thermal power. In reviewing the power ascension test program, the staff was unable to locate a test abstract that addressed this testing. In RAI 261.007b, the staff requested that the applicant provide additional information regarding performance of the failed fuel detection system testing during power ascension testing. In its November 15, 2002, RAI response, the applicant stated that the primary sampling system detects failed fuel in the AP1000 design. This system is tested prior to power ascension tests. While proper operation of the primary sampling system depends on system temperature and pressure, it does not depend on plant power. The staff has determined that the proposed testing of the sampling system is adequate to verify its capability, as the capability to obtain a primary sample does not depend on reactor power. Therefore, the staff concludes that the applicant adequately addressed failed fuel testing.

(5) RG 1.68, Appendix A, Section 5.m.m recommends that the power ascension test program demonstrate that the dynamic response of the plant is in accordance with the design for the case of automatic closure of all main steamline isolation valves (MSIVs). In reviewing the power ascension test program test abstracts,

the staff noted that no MSIV closure testing occurs during power ascension testing. In RAI 261.007b, the staff requested that the applicant provide additional information regarding performance of MSIV closure testing. In its November 15, 2002, RAI response, the applicant stated that the dynamic response of the plant to closure of all MSIVs is bounded by a plant trip from 100 percent power, which is performed in test abstract 14.2.10.4.24.

In RAI 261.018, the staff requested the applicant to provide additional information regarding the basis for the statement that a plant trip from 100 percent power bounds the MSIV closure transient. This was Open Item 14.2.10-4 in the DSER.

In a letter dated August 1, 2003, the applicant stated the following:

> Rather than say the plant trip from 100% power, which is performed in test abstract 14.2.10.4.24, 'bounds' the MSIV test identified in RG 1.68, Appendix A, Test 5.m.m, it would be more correct to say that the proposed test allows sufficient information to be obtained to demonstrate that the dynamic response of the plant is in accordance with the design. The pressure transient in the plant resulting from opening the main generator breakers during the proposed test can be compared to analyses and is sufficient to confirm that the plant responds as predicted.

The applicant stated that licensees have not traditionally performed Test 5.m.m on its plants because closure of the MSIVs at full power or reduced power would lead to a severe transient, which could lead to opening of the plant's safety valves. The staff determined that this information provides an acceptable basis for the applicant's decision not to perform the MSIV closure transient at 100 percent power and is consistent with SRP Section 14.2 and RG 1.68. Therefore, Open Item 14.2.10-4 is resolved.

- In RAI 261.010, the staff identified two additional power ascension tests where it required additional information to complete its review. These tests involve the determination that steady-state core performance is acceptable, and gaseous and liquid radioactive waste processing, storage, and release systems are in accordance with the design. The RAI responses and the associated NRC staff evaluation are described below:

  (1) RG 1.68, Appendix A, Item 5.b, recommends that power ascension testing determine that the steady-state core performance is in accordance with the design. Specifically, RG 1.68 states that sufficient measurements and evaluations should be conducted to establish that flux distributions, local surface heat flux, linear heat rate, departure from nucleate boiling ratio, radial and axial power peaking factors, and other important parameters are in accordance with the design values throughout the permissible range of power to flow conditions.

In reviewing the proposed AP1000 power ascension test program, the staff noted that the test abstract in DCD Tier 2, Section 14.2.10.4.2, does not reference (1) the test methods necessary to generate data from in-core maps to verify that core power peaking and axial distributions are consistent with design predictions, or (2) the data collection methods necessary to establish local surface heat flux, linear heat rate, departure from nucleate boiling, and radial power peaking factors.

In its November 15, 2002, response to RAI 261.010, the applicant noted that the COL applicant is responsible for providing test specifications and test procedures for startup tests and that these procedures will meet appropriate regulatory guidance. The applicant also revised the test abstract wording in DCD Tier 2, Section 14.2.10.4.2, to generally state that in-core maps would verify that core power distribution is consistent with design predictions and TS requirements, rather than specifically referencing peaking factor measurements. In a February 13, 2003, conference call with the applicant, the staff requested additional information concerning testing of the thermal limits noted in RG 1.68. The applicant stated that the TS surveillance test program for thermal limits currently includes this information; therefore, the applicant considered it repetitious to place the information in DCD Tier 2, Section 14.2.10.4.2. The applicant revised DCD Tier 2, Section 14.2.10.4.2, to add a cross reference to TS 3.2, "Power Distribution Limits," to address the applicable surveillance test for thermal limits. Because the TS surveillance test program verifies the thermal limits, and the cross reference makes this clear, the staff concludes that this issue is satisfactorily resolved.

(2) RG 1.68, Appendix A, Section 5.c.c recommends that power ascension testing include demonstration that the gaseous and liquid radioactive waste processing, storage, and release systems operate in accordance with design. In reviewing the initial test program, the staff noted that the test abstracts described in DCD Tier 2, Sections 14.2.9.3.1, "Liquid Radwaste System Testing," and 14.2.9.3.2, "Gaseous Radwaste System Testing," specify performance of gaseous and liquid radioactive waste system testing during low-power testing, rather than power ascension testing. The staff determined that the applicant did not adequately justify performance of these tests at a power level below those typical for power ascension testing. The staff noted that performance of this testing at a lower power level could reduce the production of liquid and gaseous radioisotopes as compared to performance of this testing during the power ascension test phase.

In its November 15, 2002, RAI response, the applicant stated that testing of the gaseous and liquid radioactive waste processing, storage, and release systems is performed at low power to minimize the negative impact of any system not performing as designed. The applicant noted that low-power testing confirms that the systems perform as designed and, therefore, additional testing at high plant power is not necessary. However, the staff disagreed with the conclusion that low-power testing of these systems adequately demonstrates their capability. In a February 13, 2003, conference call with the staff, the applicant agreed to add appropriate test abstract information to DCD Tier 2, Section 14.2.10.4, "Power Ascension Tests," to perform the testing recommended by RG 1.68, Item 5.c.c. This was Confirmatory Item 14.2.10-2 in the DSER.

In a March 12, 2003, response to this issue, the applicant stated that monitoring of system performance is done continuously, as described in DCD Tier 2, Sections 11.2.1.2.4, "Controlled Release of Radioactivity," 11.3.3, "Radioactive Releases," and 11.5.3, "Effluent Monitoring and Sampling."

The applicant also noted that the value of testing the system during the power ascension tests is limited by the complexity of the interaction between radwaste source terms and system performance. Instead, the low-power testing confirms that system equipment (i.e., pumps, valves, etc.) performs as expected and the continuous monitoring constitutes continuous testing and verification of adequate purification performance.

The staff determined that DCD Tier 2, Section 14.2.10.4.14, "Radiation and Effluent Monitoring System," also addresses radioactive waste processing, storage, and release system testing. Based on the system testing described and the information given above, the staff found that added testing during the power ascension test phase was unnecessary. This conclusion is consistent with SRP Section 14.2 and RG 1.68. Therefore, Confirmatory Item 14.2.10-2 is resolved.

During the design-specific review for the power ascension test program, the staff identified three other areas for which it required additional information to complete its review. These issues, identified as Open Items 14.2-1.w, 14.2-1.x, and 14.2-1.y, are discussed below:

- In Open Item 14.2-1.w, the staff requested that the applicant "explain why Xenon and Samarium equilibrium is not part of the prerequisites if it is expected that T_{avg} will return to T_{ref}." In its response to Open Item 14.2-1.w, dated August 26, 2003, the applicant stated the following:

  This test is performed by manually varying T_{avg} and then placing the reactor coolant system in automatic and confirming that T_{avg} is restored to T_{ref} setpoint tolerance without manual intervention. This test takes a very short time (a few minutes) to complete, so that Xenon and Samarium concentration changes during the duration of the test are not significant. Therefore, since Xenon and Samarium time constants are significantly longer that the control rod response, Xenon and Samarium equilibrium conditions are not required for this power ascension test.

  Specific information on Xenon and Samarium concentrations variations and equilibrium conditions and any other related power ascension testing guidance are provided in the detailed startup test procedures and the startup test program reference document developed by the COL applicant to support plant startup testing. Due to the short duration of this test, no prerequisites are needed to the DCD discussion or the detailed test procedures for this test.

The NRC staff agreed with the applicant's response that the short duration of this test does not require prerequisites. Based on this response, the staff concludes that no revision to the DCD is needed. Therefore, Open Item 14.2-1.w is resolved.

- In Open Item 14.2-1.x, the staff requested that the applicant clarify load swing tests from 100 percent power. Specifically, the applicant should clarify that test abstract 14.2.10.4.20, "Load Swing Test," does not call for a 10 percent load increase from 100 percent power, or the applicant should specify the required operator response. In its response dated August 26, 2003, the applicant stated the following:

  Since 100 percent reactor power is not allowed to be exceeded, the load swing test at 100 percent power consists of a 10 percent power load decrease to 90 percent power, followed by a 10 percent power load step increase. This prevents exceeding 100 percent power.

The applicant revised the test abstract 14.2.10.4.20, to state that "core power should not exceed 100 percent as indicated by the excore nuclear instrumentation." The staff finds this revision to be acceptable. Therefore, Open Item 14.2-1.x is resolved.

- In Open Item 14.2-1.y, the staff requested that the applicant explain the origin of the core burnup data for the startup test of a new plant in test abstract 14.2.10.4.23, "Hot Full Power Boron Endpoint." In its response dated August 26, 2003, the applicant stated the following:

  The current core burnup data identified in the prerequisites for Startup Test 14.2.10.4.23, are generated during core power operation associated with the power ascension testing. The power generation results in a small amount of fuel burnup and, therefore, core burnup data can be taken during the power ascension testing for use in the hot full power boron endpoint test procedure.

  The staff agreed that only a small amount of fuel burnup occurs during power ascension testing, and the hot full power boron endpoint test procedure covers this detailed information; therefore, the staff finds that a revision to the DCD is not needed. Therefore, Open Item 14.2-1.y is resolved.

In conclusion, the staff reviewed all the power ascension test abstracts used to verify that the testing scope, general test methods, performance criteria and acceptance criteria are sufficient to test the SSCs important to safety during the power ascension test phase. The staff found that the applicant took one exception to RG 1.68, Appendix Action, Section 5L. The staff concluded that this exception prevents damage to fuel cladding; therefore, it is acceptable (see Section 14.2.10.4, Item (3) of this report). The staff found that all of the other power ascension test abstracts met the power ascension test attributes in SRP Section 14.2 and the applicable power ascension tests recommended in RG 1.68.

14.2.11 Conclusions

For each phase of the initial test program, the applicant provided test abstracts which included the objectives of each test, a summary of prerequisites and test method, and specific acceptance criteria. The initial test program addressed programmatic aspects, including consideration of organization and staffing; preparation, review, and technical content of test procedures; conduct of the test program; review, evaluation, and approval of test results; and utilization of reactor operating and testing experiences.

The staff completed its review of the AP1000 initial test program for design certification in accordance with the requirements of 10 CFR 52.79(b) and 50.34(b)(6)(iii) and Appendix A, "General Design Criteria," and Criterion XI, "Test Control," of Appendix B, "Quality Assurance," to 10 CFR Part 50. The staff determined that the applicant adequately addressed the methods and guidance in SRP Section 14.2, Revision 2, and all the applicable RGs (e.g., RG 1.68) referenced in SRP Section 14.2 in developing the AP1000 initial test program. The AP1000 initial test program will demonstrate, with reasonable assurance, that the SSCs important to safety will adequately perform their intended function.

Based on a review of the testing scope, general test methods, test objectives, and test performance criteria and acceptance criteria discussed in DCD Section 14.2, "Initial Test Program," the staff concludes that the applicant provided sufficient information in the initial test program to test all SSCs important to safety in the AP1000 design to satisfy the requirements of SRP Section 14.2 and the RGs referenced in SRP Section 14.2. Therefore, the staff finds the initial test program for the AP1000 design to be acceptable. On this basis, Open Item 14.2-1 is resolved.

14.3 Tier 1 Information

14.3.1 Introduction

This section describes the staff's evaluation of the DCD Tier 1 information for the AP1000 design. The Tier 1 information is derived from the AP1000 Tier 2 information. Specifically, this information includes the following:

- definitions and general provisions
- design descriptions
- inspections, tests, analyses, and acceptance criteria
- significant site parameters
- significant interface requirements

The applicant intends to have this Tier 1 information certified in a design certification rulemaking pursuant to Subpart B of 10 CFR Part 52. To be certified, the Tier 1 information must verify the complete scope of the AP1000 design and that the regulations applicable to the AP1000 scope of design are met. The amount of information in the Tier 1 design descriptions is proportional to the safety significance of the structures and systems in the standard plant design. The Tier 1 design descriptions are binding requirements for the life of a facility referencing the certified design.

The staff reviewed the Tier 1 information in accordance with the guidance provided in SRP Section 14.3, "Inspections, Tests, Analyses, and Acceptance Criteria—Design Certification," the requirements in 10 CFR 52.47 and the Atomic Energy Act of 1954, as amended. The NRC prepared the draft SRP Section 14.3 based on the experience gained in its review of the evolutionary designs (ABWR and System 80+), which were certified in 1997.

The applicant organized its Tier 1 information in a manner similar to that used for the evolutionary designs, as described in SRP Section 14.3. Therefore, Tier 1, Section 2.0, "System-Based Design Description and ITAAC," establishes the design descriptions and ITAAC for all of the systems in the AP1000 design; Tier 1, Section 3.0, "Non-System Based Design Descriptions and ITAAC," establishes the non-system-based design descriptions and ITAAC that apply to multiple systems or structures. In DCD Tier 1, Section 2.0, "System Based Design Descriptions and ITAAC," the applicant provided a Tier 1 entry (subsection) for every system in its design, thereby meeting the requirement to verify the full scope of the standard plant design. In addition, although the applicant provided a Tier 1 entry for every system that is either fully or partially captured within the scope of the AP1000 standard plant design, the amount of information in a given subsection is proportional to the safety significance of the particular system. The ITAAC portion of the Tier 1 information is used to verify that the as-built facility conforms to the applicable regulations.

14.3.2 Inspection, Test, Analyses, and Acceptance Criteria

As stated above, the staff performed its review of the system and non-system-based ITAAC in accordance with draft SRP Section 14.3. Several open and confirmatory items were identified in the DSER. The following describes the resolution of these open and confirmatory items:

- Open Item 14.3.2-1: In DCD Tier 1, Section 2.2.1, "Containment System," the staff found that Item 2 under the design description for the containment system stated that the components identified in DCD Tier 1, Table 2.2.1-1 and the piping identified in DCD Tier 1, Table 2.2.1-2 are designed and constructed in accordance with ASME Code Section III requirements. However, during the April 2–5, 2003, design audit, the staff found that the applicant did not complete the final analyses and design of the containment vessel, including attached components and piping systems (see Section 3.8.2.1 of this report). The staff designated this issue related to the containment design as Open Item 14.3.2-1 in the DSER.

  During the audits conducted from October 6–9, 2003, and December 15–16, 2003, the staff reviewed the evaluation reports prepared by the applicant and found the applicant's evaluation of the containment vessel design adequacy to be acceptable. Section 3.8.2.1 of this report discusses the details of the staff's review. Therefore, Open Item 14.3.2-1 is resolved.

- Open Item 14.3.2-2: In DCD Tier 1, Section 2.2.1, the applicant should add the phrase "structural integrity and" to (1) design description Item 5 for the containment system, and (2) Subitem 5.ii under the acceptance criteria in ITAAC Table 2.2.1-3. The sentence should read "... the seismic Category I equipment can withstand seismic design basis dynamic loads without loss of structural integrity and safety function." This issue was Open Item 14.3.2-2 in the DSER.

  The staff confirmed that the applicant added the phrase "structural integrity and" in the above-mentioned locations of DCD Tier 1, Section 2.2.1. On this basis, Open Item 14.3.2-2 is resolved.

- Open Item 14.3.2-3: In DCD Tier 1, Section 2.2.1, the applicant should designate the thickness of the steel containment vessel as Tier 1 information and specify it in DCD Tier 1, Section 2.2.1 or list it in DCD Tier 2, Table 3.3-1. This was Open Item 14.3.2-3 in the DSER.

  The applicant revised DCD Tier 2, Section 3.8.2.1.1, "General [Description of Containment]," to designate the thickness of the steel containment vessel as Tier 2* information for which any proposed change to the containment wall thickness will require NRC approval prior to implementation of the change. The staff accepts the designation of the wall thickness as Tier 2* information. Therefore, Open Item 14.3.2-3 is resolved.

- Open Item 14.3.2-4: In DCD Tier 1, Section 2.3.2, "Chemical and Volume Control System," the staff found that incomplete design commitments related to controls and displays exist in the current system-based ITAAC. For example, one current description states that, "[c]ontrols exist in the MCR [main control room] to cause the pumps identified in [DCD Tier 1,] Table 2.3.2-3, to perform the listed function." The staff recommends revising this design commitment to indicate that not only should the controls exist in the MCR and perform their intended functions, but the design of the controls should make them usable by operators. The staff suggested the following revision to accommodate this change, "[c]ontrols exist in the MCR to cause the pumps identified in [DCD Tier 1,] Table 2.3.2-3 to perform the listed function and are designed in accordance with state-of-the-art human factors principles as required by 10 CFR 50.34(f)(2)(iii)." The same concern applies to the current design commitment statements related to displays. As an example, the current design commitment, "[s]afety-related displays identified in [DCD Tier 1,] Table 2.3.2-1 can be retrieved from the MCR," should be changed to "[s]afety-related displays identified in [DCD Tier 1,] Table 2.3.2-1 can be retrieved from the MCR, perform their intended function, and are designed in accordance with state-of-the-art human factors principles as required by 10 CFR 50.34(f)(2)(iii)." These recommended changes to the examples cited above apply to other current design commitments for system-based ITAAC. This was Open Item 14.3.2-4 in the DSER.

In its June 21, 2003, response, the applicant indicated that the proposed words do not need to be added to the system-based Tier 1 ITAAC because DCD Tier 1, Section 3.2, "Human Factors Engineering," is the appropriate place to have the design commitments that demonstrate compliance with 10 CFR 50.34(f)(2)(iii). DCD Tier 1, Section 3.2 stipulates that the design of the MCR controls are consistent with state-of-the-art human factors principles. This applies to each individual control covered by the various system-based ITAAC. Based on this information, the staff agrees with the applicant's response; therefore, Open Item 14.3.2-4 is resolved.

- Open Item 14.3.2-5: In DCD Tier 1, Section 2.3.5, "Mechanical Handling System," the design descriptions (Items 3.b and 3.c) for the equipment hatch hoist and the maintenance hatch hoist are not identified as single-failure proof as they are in Tier 2. In addition to not being identified as single-failure proof, DCD Tier 1, Table 2.3.5.2 does not require a test, inspection, or analysis to demonstrate whether these equipment items will meet their design criteria. As such, the staff finds the design description in Tier 2, is inconsistent with that of the ITAAC. This was Open Item 14.3.2-5 in the DSER.

  The applicant revised DCD Tier 2, Section 9.1.5, "Overhead Heavy Load Handling Systems," to state that the maintenance hatch hoist is non-single-failure proof, but is operational after a seismic event. The equipment hatch hoist is single-failure proof. In addition, the applicant revised DCD Tier 1, Section 2.3.5, "Design Description," to be consistent with the information in DCD Tier 2. DCD Tier 1, Table 2.3.5-2, "Inspection, Test, Analysis and Acceptance Criteria," includes an inspection, test, and analysis for the equipment hatch hoist. Consequently, the design description in Tier 2 is now consistent with the ITAAC (Tier 1). Therefore, Open Item 14.3.2-5 is resolved.

- Open Item 14.3.2-6: The open item associated with DCD Tier 1, Section 2.3.9, "Containment Hydrogen Control System," remained open because hydrogen control was an open item in the DSER (see Section 6.2.5 and the resolution of DSER Open Item 6.1.1-1 in this report for details). The AP1000 Tier 2 information was written in anticipation of a rule change to 10 CFR 50.44 that would relax certain requirements, but this change was not finalized when the DSER was issued. This was Open Item 14.3.2-6 in the DSER.

  Subsequent to the publication of the DSER, the NRC completed the anticipated change to its regulations regarding the control of combustible gas in containment. Accordingly, the staff has completed its review in Section 6.2.5 of this report with no open items. However, as part of its review, the staff requested that the applicant revise DCD Tier 2, Section 6.2.4, "Containment Hydrogen Control System," to reflect that the containment hydrogen monitors are powered by the non-Class 1E dc and UPS (uninterruptible power system) system. This change demonstrates compliance with the revised regulations specified in 10 CFR 50.44 and is consistent with draft RG 1.7, Revision 3. The staff also requested that the applicant add an equivalent statement to DCD Tier 1, Section 2.3.9, and implementing provisions to DCD Tier 1, Table 2.3.9-3. The staff verified that this information was added to the DCD. Therefore, Open Item 14.3.2-6 is resolved.

- Open Item 14.3.2-7: In DCD Tier 1, Section 2.3.19, "Communication Systems," the applicant did not identify ITAACs for the communication system (EFS), as discussed in DCD Tier 2, Section 9.5.2, beyond those given in DCD Tier 1, Tables 2.3.19-2 and 3.1-1 (emergency response facilities). The applicant provided no assurance that its proposal will satisfy the appropriate tests and confirmatory criteria to meet regulatory requirements, especially 10 CFR 73.55(e) through (g) and noise level considerations for worst-case postulated noise levels. The staff asked the applicant to provide appropriate ITAAC for all of the AP1000 communication systems. This was Open Item 14.3.2-7 in the DSER.

  The applicant addressed this item in a response to RAI 420.048 dated May 14, 2003. The applicant updated DCD Tier 2, Sections 13.6.9, "Security Power Supply System," 13.5.1, "Combined License Information Item," 9.5.2.2.1, "Wireless Telephone System," 9.5.2.5.2, "Emergency Offsite Communications," and 14.2.9.4.13, "Passive Core Cooling System Testing," to address this issue. In addition, the RAI response stated that the COL applicant will test the communication equipment to verify that this equipment can operate under maximum plant noise conditions. The staff finds that these responses have addressed the appropriate tests, and confirmatory criteria will be applied to meet the requirements of 10 CFR 73.55(e) through (g) and noise level considerations for worst-case postulated noise levels. Therefore, Open Item 14.3.2-7 is resolved.

- Open Item 14.3.2-8: The staff had not completed its review of the ITAAC In DCD Tier 1, Sections 2.6.9, "Plant Security System," and 2.6.10, "Closed Circuit TV System," because the review of the security program for the AP1000 had not yet been completed (see Section 13.6 of this report). This was Open Item 14.3.2-8 in the DSER.

  The staff subsequently completed its review of DCD Tier 2, Section 13.6, "Security." As a result, the staff informed the applicant that the plant security system, as listed in DCD Tier 2, Table 1.7-2, "AP1000 System Designators and System Diagrams," was fully in scope for the design certification review, which was inconsistent with the language in DCD Tier 2, Section 13.6. In addition, the closed circuit TV system was listed as partially out of scope, which also was inconsistent because this item was not discussed in DCD Tier 2, Section 13.6 and appeared to be the responsibility of the COL applicant.

  In response to this issue, the applicant revised DCD Tier 2, Table 1.7-2 to indicate that the plant security system was partially out of scope and the closed circuit TV system was wholly out of scope. In addition, the applicant revised DCD Tier 2, Table 14.3-1, "ITAAC Screening Summary," to indicate that the closed circuit TV system was not selected for ITAAC. The applicant also deleted the reference to the closed circuit TV system in DCD Tier 1, Section 2.6.10 and renumbered the sections. The staff reviewed the applicant's changes to the DCD and found them acceptable.

  The staff also reviewed DCD Tier 1, Table 3.3-6, Item 14, concerning a security ITAAC included in DCD Tier 1, Section 3.3, "Buildings." The staff determined that additional information was required to verify that the security design characteristics had been incorporated in the as-built AP1000 design. In a conference call on May 6, 2004, the applicant committed to revise Item 14 and add four additional ITAACs (Items 15 through 18) to ensure the specific security design commitments were included in the ITAACs. Security design characteristics to be included in the ITAACS are: bullet resistant barriers, vital area designations for the central alarm station and main control room, security power supply located in a vital area, vital area design, alarm annunciation and locks. In addition, the applicant committed to revise DCD Tier 1, Section 3.3 to include the new design commitments specified in Items 14 through 18 as discussed above. The staff reviewed the changes to the DCD and concluded that they are acceptable. Therefore, Open Item 14.3.2-8 is resolved.

- <u>Open Item 14.3.2-9</u>: In RAI 252.001, the staff requested information related to the geometry, fabrication, materials, accessibility for inspection, and operating conditions for control rod drive system penetrations, based upon recent operating experience (see NRC Bulletins 2001-01, 2002-01, and 2002-02). Since the RAI was issued, the staff has issued Order EA-03-009 to operating license holders. This order is related to the inspection for cracks in these penetrations and attachment welds. The staff subsequently issued followup questions to the applicant related to changes in design and fabrication to reduce residual stresses, the ability to visually inspect 360 degrees around each nozzle, preservice volumetric inspection, and the determination of operating head temperature. The applicant responded to the followup questions in a letter dated April 7, 2003. The staff requested that the applicant provide a proposed ITAAC related to the issues noted above and discussed in the RAI responses. This was Open Item 14.3.2-9 in the DSER.

  In a letter dated May 21, 2003, the applicant stated that the AP1000 design provides access and inspectability for inservice inspection of ASME Code components and control rod drive system penetrations. Furthermore, the staff has determined, based on experience with operating reactors, that future reactor pressure vessel insulation will be removable to facilitate inspections. The staff finds the design for access and inspectability and the preservice baseline inspections described in DCD Tier 2, Section 5.3.4.7, "Inservice Surveillance," to be acceptable. Therefore, the staff concludes that an ITAAC in this area is not necessary and Open Item 14.3.2-9 is resolved.

- <u>Open Item 14.3.2-10</u>: Operating experience continues to show cracking of Alloy 600 components. Recent experience appears to indicate that cracking has even occurred in welds or components not previously expected to crack, based on the temperature of the weld or component and the time in service. The staff believes that using Alloy 690 materials in contact with reactor coolant is a substantial improvement over the materials currently employed by the industry. However, data currently available do not demonstrate that cracking in these welds and components will not occur over the projected 60-year design lifetime of an AP1000 plant (40-year period of the COL plus a potential 20-year license renewal period). The staff also believes that bare metal visual inspection of these locations is highly effective in identifying locations where cracking occurs. The staff asked the applicant to provide information to describe the extent to which the design of the insulation of all Alloy 600/690 components and welds in the reactor coolant pressure boundary (not just in the upper reactor vessel head penetrations) will readily facilitate bare metal visual inspection during refueling outage conditions. The staff requested that the applicant provide a proposed ITAAC to verify that all Alloy 600/690 components and welds in the reactor coolant pressure boundary are identified and are readily accessible for bare metal visual inspection. This was Open Item 14.3.2-10 in the DSER.

In a letter dated May 21, 2003, the applicant confirmed the accessibility of all components with Alloy 690-type materials for inspection and confirmed that no Alloy 600 materials come in contact with the primary reactor coolant. The staff has determined, based on experience with operating reactors, that insulation can be removed for visual inspection, if necessary. Since removal of insulation makes these components accessible for inspection, and since any future redesign of insulation to facilitate more rapid inspection is not a major modification, the staff concludes that the applicant's response is acceptable and an additional ITAAC is not necessary. On this basis, Open Item 14.3.2-10 is resolved.

- Open Item 14.3.2-11: The staff reviewed Tier 2, Section 5.3.4, as it applies to pressurized thermal shock in accordance with SRP 5.3.2, "Pressure-Temperature Limits and Pressurized Thermal Shock." Section 50.61 of 10 CFR Part 50, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," defines the fracture toughness requirements for protection against pressurized thermal shock (PTS) events. The requirements in 10 CFR 50.61 establish the PTS screening criteria below which no additional action is required for protection from PTS events. The screening criteria are given in terms of reference temperature (RT_{PTS}). These criteria are 148.0 °C (300 °F) for circumferential welds and 132.2 °C (270 °F) for plates, forgings, and axial welds. To verify that the design will be in accordance with the regulatory requirements associated with PTS, the staff requested that the applicant provide an appropriate ITAAC. The staff also suggested, as a design commitment for this ITAAC, that the amount of copper and nickel in the reactor vessel materials and the projected neutron fluences for the 40-year period of the COL will result in RT_{PTS} values lower than the screening criteria contained in 10 CFR 50.61. This was Open Item 14.3.2-11 in the DSER.

  By letter dated June 23, 2003, the applicant indicated that the DCD provides bounding values of nickel and copper in the reactor vessel materials. The applicant further indicated that the preliminary end-of-life RT_{PTS} values for the forging and beltline weld fall well below the screening criteria given in 10 CFR 50.61. These preliminary values are based on the bounding nickel and copper values and on the projected neutron fluences for the 40-year period of the COL. The staff concludes that an ITAAC in this area is not necessary because it is unlikely that future reactor vessels will contain unacceptable amounts of copper and nickel. On this basis, Open Item 14.3.2-11 is resolved.

- Open Item 14.3.2-12: In DCD Tier 1, Section 3.1, "Emergency Response Facilities," the staff found this ITAAC unacceptable because it did not address the radiological habitability or the ventilation system for the technical support center, both of which should be the same as, or comparable to, the MCR ITAAC. This was Open Item 14.3.2-12 in the DSER.

The applicant added Item #6 of DCD Tier 1, Section 3.1, "Emergency Response Facilities," to state that the technical support center provides a habitable work space environment. The applicant also revised DCD Tier 1, Table 3.1-1, "Inspections, Tests, Analyses, and Acceptance Criteria," to add this design commitment. Therefore, Open Item 14.3.2-12 is resolved.

- Open Item 14.3.2-13: In DCD Tier 1, Section 3.3, "Buildings," Item 2.a of the design description and DCD Tier 1, Table 3.3-6 state that the NI structures, including the critical section listed in DCD Tier 1, Table 3.3-7, are seismic Category I and are designed and constructed to withstand design-basis loads (including seismic loads), as specified in the design description, without loss of structural integrity and their safety-related functions. However, as identified in Open Items 3.7.2.3-1, 3.7.2.3-3, and 3.8.5.4-1, the applicant did not demonstrate that the foundation mat will not lift up, and/or that the shear walls will not crack, during a postulated seismic event. The phenomena of the foundation mat uplifting and shear wall cracking will directly affect the design adequacy of the NI SSCs, including the thickness of structural elements listed in DCD Tier 1, Table 3.3-1 and safety-related piping systems. This was Open Item 14.3.2-13 in the DSER.

  As discussed in Sections 3.7.2 and 3.8.5 of this report, the applicant has properly (1) demonstrated that the uplifting of the foundation mat under an SSE is insignificant, and (2) considered the effects of shear wall cracking in the analysis and design of the NI structures. On the basis that the applicant has adequately resolved Open Items 3.7.2.3-1, 3.7.2.3-3, and 3.8.5.4-1. Therefore, Open Item 14.3.2-13 is resolved.

- Open Item 14.3.2-14: In Tier 1, Table 3.3-6, acceptance criteria 2.g states that the tolerance on the height of the containment vessel is +30.5 cm, - 15.2 cm (+12", -6") and the tolerance on the inside diameter is also +30.5 cm, - 15.2 cm (+12", -6"). The information included in Tier 2 related to the containment design does not address the +30.5 cm (+12") tolerance on the inside diameter. All of the applicant's analyses, calculations, and responses to the RAIs related to the containment vessel use the nominal inside diameter of 39.62 m (130 ft) as a basis. From its review, it is the staff's understanding that the inside diameter of the vessel wall, currently specified for 39.62m (130 ft), marginally meets ASME Code allowable tolerances. Adding 30.5 cm (12") to the vessel diameter will reduce the design margin. The staff request the applicant to justify the use of the proposed tolerances. This was Open Item 14.3.2-14 in the DSER.

  In its response dated July 7, 2003, the applicant stated that design commitment 2.c of Tier 1, Table 3.3-6, states that, "The containment and its penetrations are designed and constructed to ASME Code Section III, Class MC." ASME Code, Section III, Division 1, Subsection NE requires that, "For components subjected to internal pressure, the inside diameter shall be taken as the nominal inner face." The Code further states that, "The difference between the maximum and minimum inside diameters [of the fabricated vessel] at any cross section shall not exceed one (1) percent of the nominal diameter at the cross section under consideration." The Code then requires that a report be prepared as an addendum to the design report that compares the final as-built vessel to the design report. Differences must be justified or the design report must be revised. As a result, if the as-built inner diameter deviates from the design inner diameter, the difference must be addressed in the as-built reconciliation. The staff considers the applicant's response to be acceptable and, therefore, Open Item 14.3.2-14 is resolved.

- Open Item 14.3.2-15: In DCD Tier 1, Section 3.7, "Design Reliability Assurance Program," the staff found that the applicant did not update the list of risk-significant components in DCD Tier 1, Table 3.7-1 to include all risk-significant SSCs from the list of risk-significant SSCs identified in DCD Tier 2, Table 17.4-1, "Risk Significant SSCs within the Scope of D-RAP." Specifically, the list of risk-significant components should include the following:

  - compressed and instrument air system air compressor transmitter
  - passive containment cooling system diverse third motor-operated drain isolation valve function
  - IRWST vents
  - normal residual heat removal valve V055 function
  - feedwater isolation valves

  As discussed in Section 17.4 of this report, the staff determined that DCD Tier 2, Table 17.4-1 contained an acceptable list of risk-significant SSCs under the scope of D-RAP. In Table 17.4-1, the applicant also removed the safety-related passive core cooling condensate sump recirculation valves' automatic open function from the D-RAP for the AP1000 design, and DCD Tier 1, Table 3.7-1 should reflect this. This was Open Item 14.3.2-15 in the DSER.

  In a response dated July 1, 2003, the applicant provided the following information based on its review of DCD Tier 2, Table 17.4-1 and DCD Tier 1, Table 3.7-1:

  (1) The probabilistic risk assessment (PRA) importance of the compressed and instrument air system, air compressor pressure transmitter had been reevaluated. Based on the current AP1000 PRA, this instrument just meets the D-RAP selection criteria (risk achievement worth (RAW), risk reduction worth (RRW)) for large release frequency, although it does not meet the D-RAP selection criteria for core damage frequency. Furthermore, conservatisms in the PRA have resulted in the overestimation of RAW/RRW values for this instrument. These conservatisms result from not modeling some plant features that would have reduced the PRA importance of this instrument. Based on this

reevaluation, the D-RAP tables in the DCD and the ITAAC should no longer list this instrument. Therefore, the applicant removed it from DCD Tier 2, Table 17.4-1 and did not add it to DCD Tier 1, Table 3.7-1.

The staff requested that the applicant add information to this response concerning equipment that was not modeled in the PRA which would reduce the risk importance of the air compressor pressure transmitter. The applicant agreed to add information concerning instrument air bottles used to control air-operated valves in the feedwater system which would reduce the risk importance of the air compressor pressure transmitter.

(2) The applicant agreed to add the following equipment to DCD Tier 1, Table 3.7-1:

- IRWST vents
- main feedwater isolation valves

(3) The applicant stated that it need not add the third PCS water drain valve to DCD Tier 1, Table 3.7-1 because the component already exists in the table. The table lists three values under PCCWST drain isolation valves, including PCS-PL-V001A/B/C. The C valve is the diverse third drain valve.

(4) The applicant agreed that the table should also include the normal residual heat removal (RNS) valve 055. However, as indicated in DCD Tier 2, Table 17.4-1, other RNS MOVs are also required to allow the RNS to provide RCS makeup following ADS actuation, including the following:

- V011 RNS discharge containment isolation

- V022 RNS actuation containment isolation

- V055 RNS suction from the spent fuel pool cooling system cask loading pit

- V062 RNS suction from the IRWST

(5) The applicant agreed that it should remove the PXS containment recirculation MOVs (PXS-PL-V117A/B) from DCD Tier 1, Table 3.7-1, since they have been removed from DCD Tier 2, Table 17.4-1.

(6) The applicant's review also indicated that it should make the following additional changes to DCD Tier 1, Table 3.7-1:

- Add CVS makeup pump suction and discharge check valves.
- Add inverters and battery chargers for the 24-hour batteries.
- Add reactor vessel insulation water inlet and steam vent devices.
- Add reactor cavity door damper.

- Add service water cooling tower fans.
- Add low capacity chilled water subsystem.
- Add standby diesel generator room cooling fans.
- Add fuel assemblies.
- Remove PXS valves PCS-PL-V125A/B from the IRWST injection squib valve group. These valves are not squibs, and V123A/B and V125A/B lists the four squibs in these lines.

The staff finds that the applicant's response appropriately identifies all risk-significant SSCs that should be within the scope of D-RAP; however, the staff noted that the equipment identification nomenclature between DCD Tier 2, Table 17.4-1, and DCD Tier 1, Table 3.7-1, differs, making it difficult for the staff to identify like components in each table. The applicant stated that it would add the risk-significant component tag number for each component to DCD Tier 2, Table 17.4-1 to make the nomenclature between the two tables the same. The applicant revised DCD Tier 2, Table 17.4-1, to add the appropriate nomenclature to both tables. The staff finds this to be acceptable.

In addition, the staff requested that the applicant verify that the risk-significant SSCs identified in DCD Tier 2, Table 17.4-1, match the risk-significant components in DCD Tier 1, Table 3.7-1. In DCD Tier 2, Table 17.4-1, and DCD Tier 1, Table 3.7-1, the staff verified that the component lists in the two tables were identical; therefore, this part of Open Item 14.3.2-15 is resolved.

The NRC staff also noted that Westinghouse needed to add the uninterruptible power supply (UPS) Distribution Panels, EDS1-EA-1 and EDS2-EA-1, to the AP1000 D-RAP. The NRC staff determined that these components have RAW values equivalent to UPS Distribution Panels EDS1-EA-14 and EDS2-EA-14. Therefore, the AP1000 D-RAP must include EDS1-EA-1 and EDS2-EA-1. In Revision 9 to AP1000 DCD Tier 1, Table 3.7-1, "Risk Significant Components," and Tier 2, Table 17.4-1, "Risk Significant SSCs Within the Scope of D-RAP," Westinghouse added UPS Distribution Panels EDS1-EA-1 and EDS2-EA-1 to the two tables. Therefore, this part of Open Item 14.3.2-15 is resolved. Therefore, this part of Open Item 14.3.2-15 is resolved.

The NRC staff also noted that Westinghouse needed to add the uninterruptible power supply (UPS) Distribution panels, EDS1-EA-1 and EDS2-EA-1, to the AP1000 D-RAP. The NRC staff determined that these components have RAW values equivalent to UPS Distribution Panels EDS1-EA-14 and EDS2-EA-14. Therefore, the AP1000 D-RAP must include EDS1-EA-1 and EDS2-EA-1. In Revision 9 to AP1000 DCD Tier 1, Table 3.7-1, "Risk Significant Components," and Tier 2, Table 17.4-1, "Risk Significant SSCs Within the Scope of D-RAP," Westinghouse added UPS Distribution Panels EDS1-EA-1 and EDS2-EA-1 to the two tables. Therefore, this part of Open Item 14.3.2-15 is resolved. Therefore, Open Item 14.3.2-15 is resolved.

- <u>Electrical Cable Pulling</u>

In a public meeting on October 30, 2003, the staff stated that the NRC team developing the construction inspection program for new reactors identified a potential issue concerning cable pulling. The staff requested that the applicant consider verification of as-installed electrical cables be added to the AP1000 ITAAC.

The applicant stated in its response, dated November 17, 2003, that the cable pulling process will be governed by the construction procedures for the plant. In addition, an ITAAC for the cable pulling process was not included in any of the three designs previously certified. The applicant concluded that an additional ITAAC is not needed for AP1000.

The staff discussed this issue with the applicant in a conference call on January 29, 2004. The staff provided its position to the applicant prior to the call. This position is documented in the conference call summary dated March 11, 2004, and is repeated below.

> Operational experience has shown that inadequate cable installation procedures and cable pulling could cause safety-related as well as non safety-related cables (low voltage as well as medium) to fail and could challenge the performance of systems that are important to safety, and RTNSS important. Therefore, the staff has determined that ITAAC for systems important to safety should be added to verify that damage did not occur during storage, handling, and installation of all cables (power as well as instrumentation & control) whether they are Class 1E (safety), non-Class 1E, or RTNSS important. The following guidance should be used in preparing the ITAAC:
>
> IEEE Standard 422-1986 Section 10.2, "Installation," provides information such as handling or pulling cables, cable pulling lubricants, pulling winches, cable reels, pulling tension and bends. This could cause damage to the cables' sheathing, jacketing, or conductors. Section 11 of the standard provides guidance for the testing of cables after installation but before their connection to equipment, and includes cable terminations, and connections. The purpose of the tests is to verify that major cable damage did not occur during storage and installation. The following tests should be performed in conjunction with the cable manufacturer's recommendation:
>
> 1) The insulation resistance tests for low-voltage power, instrumentation and control cables should measure the insulation resistance between the conductors in the same cable and between each conductor and station ground.
>
> 2) The insulation resistance tests should be performed for the shielded and unshielded medium-voltage cables.
>
> In addition to IEEE Standards 422 and 690, NRC Information Notices IN 87-08, IN 87-52, and IN 92-01, and EPRI Final Report NP-7485, "Practices to Assure Cable Operability," dated June 1992, should be reviewed for preparation of the electrical cable ITAAC.

In its response dated February 4, 2004, the applicant stated that it has reviewed the IEEE standards, Information Notices, and the EPRI report as they related to the AP1000 design. The applicant provided the following six conclusions in its response:

Verification Programs

1. Westinghouse agrees that inadequate cable installation and handling can cause cables to fail and could challenge the performance of systems that are important to safety.

2. Proper cable installation procedures should and will be followed. DCD Tier 2, Section 8.3.1.3.1 states that the installation of cables will comply with IEEE [Standard] 422.

3. As stated in EPRI NP-7485 (page 8-41), "A universally acceptable simple in-situ cable test or cable condition monitoring method that directly indicates the cable condition or its capability to withstand accident condition does not exist."

4. Both IEEE Standards 422 and 690 allow a functional test at full voltage as an alternative to insulation resistance tests of low voltage cable. The existing DCD Tier 1 tests of instrumentation and electrical equipment provide functional tests that serve as alternatives to insulation resistance tests of low-voltage cables.

5. High potential testing of Class 1E medium-voltage cables is required by IEEE [Standard] 690; however, AP1000 does not have any Class 1E medium-voltage cables.

6. None of the non-Class 1E medium-voltage cables that have been identified as RTNSS important are in locations that will require them to withstand accident conditions.

The applicant further stated in its February 2, 2004, response:

> The cable pulling process will be governed by the construction procedures for the plant. The Quality Assurance program for procurement , fabrication, installation, construction, and testing of structures, and components in the facility will cover the cable process, as well as other installation processes...
>
> In summary, Westinghouse understands the concern regarding proper cable installation and handling; however, Westinghouse for the reasons stated above, does not believe that changes to DCD Tier 1 are needed.

The above rationale was provided by the applicant to conclude that an ITAAC does not address the needs of electrical (low and medium voltage) environmental qualification cables and connections which are important to safety, and RTNSS important. Damage during installation may void the equipment's qualification to perform its intended safety function during and after a design basis accident. The staff believed confirmation is required that the cables have been installed in such a manner that does not negate the assumptions used in the equipment qualification type testing (i.e., the cable is installed in an as-new configuration).

On July 14, 2004, a conference call was held to discuss this issue further. The applicant agreed to consider appropriate acceptance criteria for cable installation. The applicant revised DCD Tier 1, Table 2.1.2-1, item 7a to state the following:

Inspections, Test, Analyses

ii) Inspections will be performed of the as-installed Class 1E equipment and the associated wiring, cables and terminations located in a harsh environment.

Acceptance Criteria

ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in [DCD Tier 1,] Table 2.1.2-1 as being qualified for a harsh environment are bounded by type test, analyses or a combination of type tests and analyses.

Similar changes were also made to the following DCD sections.

- DCD Tier 1, Table 2.1.3-2, item 9.a
- DCD Tier 1, Table 2.2.1-3, item 6.a
- DCD Tier 1, Table 2.2.2-3, item 6.a
- DCD Tier 1, Table 2.2.3-4, item 7.a
- DCD Tier 1, Table 2.2.4-4, item 7.a
- DCD Tier 1, Table 2.3.2-4, item 6.a
- DCD Tier 1, Table 2.3.6-4, item 7.a
- DCD Tier 1, Table 2.3.13-3, item 6.a
- DCD Tier 1, Table 2.5.5-2, item 3.a
- DCD Tier 1, Table 3.5-6, item 2

The staff has reviewed the changes to the ITAACs in the DCD sections referenced above and finds them to be acceptable.

- Containment Sump

  By letter dated January 13, 2004, Westinghouse changed the design of the containment recirculation screens and the IRWST screens by increasing the fine screen area by at least a factor of 2 to 13 m^2 (140 ft^2) or more by using a folded screen design. An increased screen area will allow the screen to tolerate more debris, while lowering the water velocity at the screen face. Westinghouse also added a cross-connection pipe between the two containment recirculation screens. This design change was incorporated in DCD Tier 1, Table 2.2.3-4, Item 8.c.

- Confirmatory Items 14.3.2-1, 14.3.2-2, and 14.3.2-3: In DCD Tier 1, Section 2.7.1, "Nuclear Island Nonradioactive Ventilation System," DCD Tier 1, Table 2.7.1-1 lists the components, but neither DCD Tier 1, Figure 2.7.1-1 nor DCD Tier 2, Figure 9.4.1-1, shows them (see RAI 410.022). This was Confirmatory Item 14.3.2-1 in the DSER.

In DCD Tier 1, Section 2.7.3, "Annex/Auxiliary Building Nonradioactive Ventilation System." DCD Tier 1, Table 2.7.3-1 lists the components, but neither DCD Tier 1, Figure 2.7.3-1 nor DCD Tier 2, Figure 9.4.2-1 shows them (see RAI 410.022). This was Confirmatory Item 14.3.2-2 in the DSER.

In DCD Tier 1, Section 2.7.5, "Radiologically Controlled Area Ventilation System." DCD Tier 1, Table 2.7.5-1 lists the components, but DCD Tier 2, Figure 9.4.3-1 does not show them (see RAI 410.022). This was Confirmatory Item 14.3.2-3 in the DSER.

The staff requested in RAI 410.022 that the applicant explain why specific heating, ventilation, and air conditioning (HVAC) components are listed in the following ITAACs but are not discussed in DCD Tier 2, Section 9.4. The impacted ITAACs, which are listed in DCD Tier 1, Table 2.7.1-1, include (1) VBS-MA-11 and MA-12 instrumentation and control (I&C), Divisions B and C ancillary fans; (2) VXS-MS-04A through D MSIV, Compartments A, B, C, and D air handling units; (3) VXS-MS-08A and B valve piping penetration rooms, A and B air handling units; (4) VXS-MY-W01A, B and C annex building nonradioactive equipment room unit heaters; (5) VXS-MS-07A and B mechanical equipment area air handling units; and (6) VAS-030 fuel handling area differential pressure indicator, VAS-032 annex building differential pressure indicator, and VAS-033 auxiliary building differential pressure indicator.

In a letter dated April 24, 2003, the applicant provided a response stating that it had revised the following DCD Tier 2 sections to add the components listed above:

- Section 9.4.1.2.3.2, "Class 1E Electrical Room HVAC Subsystems" (Item 1)
- Section 9.4.2.2.1.4, "MSIV Compartment HVAC Subsystems" (Item 2)
- Section 9.4.2.2.1.6, "Valve/Piping Penetration Room HVAC Subsystems," (Item 3)
- Section 9.4.2.2.1.3, "Equipment Room HVAC Subsystems," (Item 4)
- Section 9.4.2.2.1.5, "Mechanical Equipment Areas HVAC Subsystems," (Item 5)
- Section 9.4.3.5, "Instrumentation Applications," (Item 6)

The staff reviewed the applicant's response and revisions to the DCD Tier 2 sections listed above. Since these components are defense-in-depth-related and not safety-related, nor are they important to safety, the staff finds the applicant's revisions to the DCD acceptable based on cross-component traceability between the DCD Tier 2 text description and the DCD Tier 1 table. Therefore, Confirmatory Items 14.3.2-1, 14.3.2-2, and 14.3.2-3 are resolved.

14.3.3 Design Acceptance Criteria

During the AP1000 preapplication review, the applicant requested the staff to review the acceptability of the proposed use of design acceptance criteria (DAC) to support the development of the design certification application for the AP1000 design (see Westinghouse letter dated August 28, 2000, as supplemented by its letter dated February 13, 2002, and SECY-02-0059, "Use of Design Acceptance Criteria for the AP1000 Standard Plant Design," dated April 1, 2002). The applicant stated that the AP1000 design is based closely on the AP600 design, and that it maintained the AP600 design configuration, use of proven components, design basis and licensing basis by making as few changes as possible to the AP600 design.

In seeking certification of the AP1000 design, the applicant proposed to apply the DAC approach to the I&C and human factors engineering as it did for the AP600 design. However, the applicant also proposed to apply the DAC approach to the piping and structural design, and, to some extent, the seismic analysis, citing the precedents set in the use of DAC during certification of the ABWR and System 80+ designs. After discussions with the NRC regarding the requirements of 10 CFR 52.47(a)(2), the applicant stated, as detailed in its letter of February 13, 2002, that it would (1) limit the design certification to hardrock sites and provide a seismic analysis, and (2) perform specified structural design calculations. This would provide sufficient seismic and structural design information for the staff to reach a safety determination prior to granting design certification and to preclude the need for DAC in these areas. In the same letter, the applicant provided information supporting its proposed use of DAC in the piping area. Therefore, the staff's evaluation of the AP1000 DAC approach contained herein is limited to the proposed use of DAC in the I&C, human factors engineering, and piping areas.

14.3.3.1 Instrumentation and Control System

The I&C system design uses digital computer technology for the reactor protection and control functions. Since the digital computer-based I&C systems are a rapidly changing technology, the NRC allowed the applicant to use design processes and DAC to develop, design, and evaluate the details of the design. The Tier 1 information should address the development and qualification processes for I&C equipment. Draft SRP Section 14.3.5, "Instrumentation and Controls (Tier 1)," states that for a computer-based I&C system, the Tier 1 information should include (1) design processes and acceptance criteria to be used for safety-related systems using programable microprocessor-based control equipment, (2) a program to assess and mitigate the effects of electromagnetic interference on I&C equipment, (3) a program to establish setpoints for safety-related instrument channels, and (4) a program to qualify safety-related I&C equipment for inservice environment conditions.

The Tier 1 information found in DCD Tier 1, Section 2.5.2, "Protection and Safety Monitoring System," Item 11, addresses the hardware and software development process for the design, testing, and installation of I&C equipment. Tier 1 information includes the ITAAC that describes attributes of the process for developing the I&C system, as well as attributes of the final product. The ITAAC for software and hardware verifies the applicant's implementation of the proposed design stages within the overall design process. Tier 2 information describes the various design stages in more detail. The staff has evaluated the I&C hardware and software development process addressed in Chapter 7 of this report. The staff finds that the information in Tier 1 is consistent with the information provided in Tier 2, including two references to topical reports, WCAP-15927, Revision 0, "Design Process for AP1000 Common Q Safety Systems," and CE-CES-195, Revision 1, "Software Program Manual for Common Q Systems." Therefore, the staff finds this information to be acceptable.

DCD Tier 1, Section 2.5.2, Item 3, addresses the AP1000 I&C system's capability to withstand electrical surges and its compatibility with electromagnetic interference, radiofrequency interference, and electrostatic discharge conditions that would exist before, during, and following a design-basis accident. In particular, DCD Tier 1, Section 2.5.2, Item 3, addresses whether the system could experience such conditions without the loss of a safety function for the time required to perform the safety function. The staff finds that the information in Tier 1 is consistent with the information provided in Tier 2, including the reference to topical report, CENPD-396-P, Revision 1, "Common Qualified Platform." Therefore, the staff finds this information to be acceptable.

DCD Tier 1, Section 2.5.2, Item 10, addresses the setpoint methodology, which accounts for loop inaccuracies, response time testing, and maintenance or replacement of instrumentation. The staff finds that the information in Tier 1 is consistent with the information provided in Tier 2, including the reference to WCAP-14605, "Westinghouse Setpoint Methodology for Protection Systems—AP600." Therefore, the staff finds this information to be acceptable.

DCD Tier 1, Section 2.5.2, Item 4, addresses the I&C equipment qualification program, which qualifies the Class 1E equipment for the environment that would exist before, during, and following a design-basis accident. If qualified, equipment would experience such conditions without the loss of a safety function for the time required to perform the safety function. The staff finds that the information provided in Tier 1 is consistent with the information provided in Tier 2, including the reference to CENPD-396-P. Therefore, the staff finds this information to be acceptable.

DCD Tier 1, Section 2.5.1, "Diverse Actuation System," has addressed a concern with regard to software common mode failure. The diverse actuation system uses an operating system and programming language that are different from those used in the protection and safety monitoring system for performing comparable safety system actuation functions. The diverse actuation system implements manual initiation functions in a manner that bypasses the control room multiplexers and the signal processing equipment to ensure manual initiation capability in the event of loss of the multiplexers. The staff finds that the defense-in-depth and diversity provisions provided in Tier 1 are consistent with the information provided in Tier 2, including the reference to WCAP-15775, Revision 2, "AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report." Therefore, the staff finds this information to be acceptable.

The staff found that certain Tier 1 information was incomplete. The staff requested certain modifications for consistency with Tier 2 information. These requests were identified as open and confirmatory items in the DSER. The following describes the resolution of these open and confirmatory items:

- Open Item 14.3.3-1: The applicant should modify DCD Tier 1, Table 2.5.1-1, "Functions Automatically Actuated by the DAS," to include "actuate core makeup tanks, and trip the reactor coolant pumps on low wide-range steam generator water level." This comment resulted from the review of DCD Tier 2, Section 7.7.1.11, "Diverse Actuation System." This was Open Item 14.3.3-1 in the DSER.

  By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Table 2.5.1-1, as suggested by the staff. The staff has verified that the information is included in the DCD. Therefore, Open Item 14.3.3-1 is resolved.

- Open Item 14.3.3-2: The applicant should modify DCD Tier 1, Section 2.5.1, design description Item 2.c, to include, "the DAS manual control bypasses the protection and safety monitoring system cabinets." This comment resulted from the review of DCD Tier 2, Section 7.7.1.11. This was Open Item 14.3.3-2 in the DSER.

  By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Table 2.5.1-4, as suggested by the staff. The staff has verified that the information is included in the DCD. Therefore, Open Item 14.3.3-2 is resolved.

- Open Item 14.3.3-3: The applicant should modify DCD Tier 1, Section 2.5.1, design description Item 3.e to include, "the DAS uses sensors that are separate from those being used by the PMS [protection and safety monitoring system] and the plant control system." This comment resulted from the review of DCD Tier 2, Section 7.7.1.11. This was Open Item 14.3.3-3 in the DSER.

  By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Section 2.5.1, Item 3.e and DCD Tier 1, Table 2.5.1-4, as suggested by the staff. The staff has verified that the information is included in the DCD. Therefore, Open Item 14.3.3-3 is resolved.

- Open Item 14.3.3-4: The applicant should modify DCD Tier 1, Section 2.5.2, "Protection and Safety Monitoring System," DCD Tier 1, Table 2.5.2-1 and DCD Tier 1, Figure 2.5.2-1, to include "two divisions of safety-related post-accident parameter displays" for consistency with the DCD Tier 1, Section 2.5.2, design description. This was Open Item 14.3.3-4 in the DSER.

  By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Table 2.5.2-1, to include, "MCR safety-related displays, Division B and Division C." DCD Tier 1, Figure 2.5.2-1 does not require revision because the box labeled "Safety-Related Displays and Indications," already includes this information. The staff has verified that DCD Tier 1, Table 2.5.2-1 was revised to include the information. Therefore, Open Item 14.3.3-4 is resolved.

- Open Item 14.3.3-5: DCD Tier 1, Table 2.5.2-4, "PMS Manually Actuated Functions," is not consistent with the information provided in DCD Tier 2, Table 7.2-4, "System-Level Manual Inputs to the Reactor Trip Functions," and DCD Tier 2, Table 7.3-3, "System-Level Manual Inputs to the ESFAS." The applicant should modify DCD Tier 1, Section 2.5.2 design description Item 6.c to clarify that the functions listed in DCD Tier 1, Table 2.5.2-4 are based on minimum inventory requirements. This was Open Item 14.3.3-5 in the DSER.

  By letters dated June 23 and July 31, 2003, the applicant submitted responses to the above open item. The applicant noted that the functions listed in DCD Tier 1, Table 2.5.2-4, are not based on minimum inventory requirements. DCD Tier 2, Section 14.3.2.1, describes the Tier 1 selection (i.e., screening) criteria. Based on the criteria that "only the information from the Tier 2 material that is most significant to safety" are included in certified design descriptions, the PMS includes the manual actuation of safety functions as a top-level function. DCD Tier 1, Table 2.5.2-4 includes the specific manual actuation functions. The PMS block and interlock functions are also important, but somewhat less important than the manual actuation of the safety functions. Therefore, DCD Tier 1, Section 2.5.2 design description, Item 9, and DCD Tier 1, Tables 2.5.2-6 and 2.5.2-7 include the automatic features of these blocks and interlocks, but do not specify the details of the operator (manual) interface. Tier 1 does not discuss the reactor trip reset because the important aspect of the reactor trip function is how the reactor is tripped, not how it is reset. The staff agrees with the applicant's justification. The staff has verified that the applicant included this information in DCD Tier 1, Table 2.5.2-4. Therefore, Open Item 14.3.3-5 is resolved.

- Open Item 14.3.3-6: The applicant should modify DCD Tier 1, Section 2.5.2 design description Item 8.b to clarify that the multiple transfer switches implement the control transfer function. Each individual transfer switch is associated with only a single safety-related or single non-safety-related group. The ITAAC table should reflect this feature. This was Open Item 14.3.3-6 in the DSER.

  By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Section 2.5.2 design description Item 8.b and DCD Tier 1, Table 2.5.2-8, as suggested by the staff. The staff has verified that the information is included in the DCD Tier 1, Section 2.5.2. Therefore, Open Item 14.3.3-6 is resolved.

- Open Item 14.3.3-7: The applicant should modify DCD Tier 1, Table 2.5.2-7, "PMS Interlocks," to include "Interlocks for the Accumulator Isolation Valves and IRWST Discharge Valve," for consistency with DCD Tier 2, Section 7.6.2.3, "Interlocks for the Accumulator Isolation Valve and IRWST Discharge Valve." This was Open Item 14.3.3-7 in the DSER.

  By letters dated June 23 and July 31, 2003, the applicant submitted responses to the above open item and noted that the interlocks for the accumulator isolation valve and IRWST discharge valve are not PMS functions. Therefore, the PMS ITAAC (DCD

Tier 1, Table 2.5.2-7) does not include them. DCD Tier 2, Section 7.6.2.3, describes this interlock. As stated in the last sentence of this section, the plant control system provides the confirmatory open and automatic open signals. This function should not be added to the Tier 1 requirements for the plant control system. AP1000 TS LCOs 3.5.1, 3.5.6, and 3.5.7 included in DCD Tier 2, Section 16.1, provide the function of assuring that these valves are open whenever these injection paths are required. The staff finds the above clarification acceptable; therefore, Open Item 14.3.3-7 is resolved.

- Open Item 14.3.3-8: The applicant should modify DCD Tier 1, Table 2.5.2-6, "PMS Blocks," to include (1) block automatic rod withdrawal (P-17), and (2) block automatic safeguards (P-4). This comment resulted from the review of the DCD Tier 2, Table 7.2-3, "Reactor Trip Permissives and Interlocks," and DCD Tier 2, Table 7.3-2, "Interlocks for Engineered Safety Features Actuation System." This was Open Item 14.3.3-8 in the DSER.

  By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Table 2.5.2-6, as suggested by the staff. The staff has verified that the information is included in DCD Tier 1, Table 2.5.2-6. Therefore, Open Item 14.3.3-8 is resolved.

- Open Item 14.3.3-9: In DCD Tier 1, Table 2.5.2-8, Item 7.c columns do not have sufficient criteria to verify that they meet the design commitment. Removal of power of non-safety components and review of gateway filtering is not enough. The language should be consistent with the acceptance criteria for other ITAACs in this section, such as Items 7.a and 7.b. The applicant should prepare a report about the major design considerations, such as quality of components, performance requirements, reliability, control access, single-failure criterion, independence, failure modes, testing, and electromagnetic interference/radio frequency interference (EMI/RFI) susceptibility. SRP Section 7.9 (data communications) may be used as guidance. This was Open Item 14.3.3-9 in the DSER.

  By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Table 2.5.2-8, Item 7.c to be consistent with Items 7.a and 7.b. The applicant appropriately identified sufficient criteria to verify that the data communication between safety and non-safety systems does not inhibit the performance of the safety function. The staff finds DCD Tier 1, Table 2.5.2-8, Item 7.c, as revised, to be acceptable. Therefore, Open Item 14.3.3-9 is resolved.

- Open Item 14.3.3-10: The DCD Tier 1, Table 2.5.2-8, ITAAC Item 7.d columns may not be sufficient to verify the design commitment, especially the terminology "non-Class 1E controls" in the performance of the operational tests. The language should be similar to other ITAACs in DCD Tier 1, Section 2.5.2, such as Items 7.a and 7.b. The applicant should prepare a report about the verification process to ensure that no potential signal from the non-safety system will prevent the PMS from performing its safety function. This was Open Item 14.3.3-10 in the DSER.

By letter dated June 23, 2003, the applicant submitted a response to the above open item and agreed to revise DCD Tier 1, Table 2.5.2-8, Item 7.d, to be consistent with Items 7.a and 7.b. The applicant appropriately identified sufficient criteria to verify that the Class 1E manual controls and automatic safety functions both have priority over non-Class 1E soft controls. The staff finds DCD Tier 1, Table 2.5.2-8, Item 7.d, as revised, to be acceptable. Therefore, Open Item 14.3.3-10 is resolved.

14.3.3.2 Human Factors Engineering

The applicant used DAC for human factors engineering (HFE) of the MCR and remote shutdown room (RSR), which is similar to its approach for the AP600 design. As discussed in Section 18.1.3 of this report, the staff reviewed the applicant's HFE elements at programmatic, implementation plan, and complete element review levels. Each level of review is associated with different DAC commitments. At the programmatic level, the DAC should include a commitment to (1) develop a detailed implementation plan and (2) complete the implementation plan and provide results to the NRC. At the implementation plan level, the DAC should include a commitment to complete the implementation plan and provide results to the staff. The staff has completed its review of DCD Tier 1, Section 3.2, "Human Factors Engineering." In its review, several issues were identified as open and confirmatory items in the DSER. The following describes the resolution of these open and confirmatory items

- Open Item 14.3.3-11: DCD Tier 1, Table 3.2-1, Item 3, acceptance criteria should include "man-in-the loop engineering test reports" as a last criterion and one of the documents to indicate that the design of the operation and control centers system conforms with the implementation plan. This was Open Item 14.3.3-11 in the DSER.

  The applicant satisfactorily addressed this open item in the DCD by including this criterion. Therefore, Open Item 14.3.3-11 is resolved.

- Open Item 14.3.3-12: The applicant should modify DCD Tier 1, Table 3.2-1, Item 4, acceptance criteria to indicate that the verification and validation implementation plan includes the following activities (terminology to be consistent with NUREG-0711, Revision 1):

  - operational conditions sampling
  - design verification (HSI task support verification and HFE design verification)
  - integrated system validation
  - human engineering discrepancy resolution
  - plant HFE/HSI (as designed at the time of plant startup) verification

  This was Open Item 14.3.3-12 in the DSER.

  In its July 1, 2003, response to open items, the applicant indicated that it would revise WCAP-15860, Section 4.6, to address the above open item. The applicant submitted WCAP-15860, Revision 1, dated August 25, 2003, but it did not address this open item. By letter dated October 16, 2003, the applicant submitted WCAP-15860, Revision 2, which revised Section 4.6, "Criteria for Selection of Test Scenarios for Dynamic Evaluations," to address this open item. WCAP-15860, Revision 2, satisfactorily addressed the NUREG-0711 criteria. Therefore, Open Item 14.3.3-12 is resolved.

- Open Item 14.3.3-13: DCD Tier 1, Table 3.2-1, Item 5, design commitment should be changed to indicate that the verification and validation implementation plan includes the following activities (terminology to be consistent with NUREG-0711, Revision 1):

  - operational conditions sampling
  - design verification (HSI task support verification and HFE design verification)
  - integrated system validation
  - human engineering discrepancy resolution
  - plant HFE/HSI (as designed at the time of plant startup) verification

  This was Open Item 14.3.3-13 in the DSER.

  In its July 1, 2003, response, the applicant satisfactorily addressed this open item by explaining that although DCD Tier 1, Table 3.2-1, "Design Commitment," statement 5, terminology differs from the terminology in NUREG-0711, Revision 1, the content and meaning remain the same and the current terminology is used to maintain consistency within the AP1000 DCD. The staff agrees with the applicant's response. Therefore, Open Item 14.3.3-13 is resolved.

- Open Item 14.3.3-14: The applicant should modify the acceptance criteria in DCD Tier 1, Table 3.2-1, Item 5, to include a new Item (a) to indicate that, "(a) Operational Conditions Sampling was conducted in accordance with the implementation plan," and re-letter the remaining criteria. This was Open Item 14.3.3-14 in the DSER.

  In its July 1, 2003, response to open items, the applicant satisfactorily addressed part of this open item by explaining that although DCD Tier 1, Table 3.2-1, Item 5, terminology differs from the terminology in NUREG-0711, Revision 1, the content and meaning remain the same and the current terminology is used to maintain consistency within the AP1000 DCD. However, the applicant did not revise WCAP-15860 to address this open item as indicated in its July 1, 2003, response. Therefore, Open Item 14.3.3-14 remained open.

  By letter dated October 16, 2003, the applicant submitted WCAP-15860, Revision 2, which revised Section 4.6, "Criteria for Selection of Test Scenarios for Dynamic Evaluations," to address this open item. WCAP-15860, Revision 2, satisfactorily addressed the NUREG-0711 criteria. Therefore, Open Item 14.3.3-14 is resolved.

- Open Item 14.3.3-15: The applicant should modify the inspections, tests and analyses of DCD Tier 1, Table 3.2-1, Item (d), to replace "design issues resolution" with "human engineering discrepancy resolution." This was Open Item 14.3.3-15 in the DSER.

In its July 1, 2003, response to open items, the applicant indicated that it would revise WCAP-15860 to address this open item. However, WCAP-15860, Revision 1, dated August 25, 2003, did not address this open item. Therefore, Open Item 14.3.3-15 remained open.

By letter dated October 16, 2003, the applicant submitted WCAP-15860, Revision 2, which revised Section 5, "Issue Resolution Verification," to address this open item by clarifying that human engineering discrepancies (HEDs) would be tracked and resolved as part of the issue resolution verification process. WCAP-15860, Revision 2, satisfactorily addressed the NUREG-0711 criteria. Therefore, Open Item 14.3.3-15 is resolved.

- Open Item 14.3.3-16: The applicant should modify the acceptance criteria in DCD Tier 1, Table 3.2-1, Item (d) to, "human engineering discrepancy resolution verification was conducted in accordance with the implementation plan and includes verification that human factors issues that were documented in the design issues tracking system and human engineering discrepancies that were identified in the design process have been addressed in the final design." This was Open Item 14.3.3-16 in the DSER.

  In its July 1, 2003, response to open items, the applicant satisfactorily addressed part of this open item by explaining that although DCD Tier 1, Table 3.2-1, Item 5, terminology differs from the terminology in NUREG-0711, Revision 1, the content and meaning remain the same and the current terminology is used to maintain consistency within the AP1000 DCD. However, the applicant did not revise WCAP-15860 to address this open item as indicated in its July 1, 2003, response. Therefore, Open Item 14.3.3-16 remained open.

  By letter dated October 16, 2003, the applicant submitted WCAP-15860, Revision 2, which revised Section 5, "Issue Resolution Verification," to address this open item by clarifying that HEDs would be tracked and resolved as part of the issue resolution verification process. WCAP-15860, Revision 2, satisfactorily addressed the NUREG-0711 criteria. Therefore, Open Item 14.3.3-16 is resolved.

- Open Item 14.3.3-17: DCD Tier 1, Table 3.2-1, Items 7.iii and 7.iv acceptance criteria do not relate to the provision of a suitable work space environment for MCR operators. Nothing in DCD Tier 1, Section 2.6.3, evaluates the adequacy/effectiveness/suitability of illumination levels for the facility or the workstations in the facilities. As part of evaluating a suitable work space environment for the MCR and RSR, the applicant should assess auditory levels (noise) as well. This comment also applies to Table 3.2-1, Item 10.ii acceptance criterion. This was Open Item 14.3.3-17 in the DSER.

  The applicant satisfactorily addressed this open item by making changes to DCD Tier 1, Section 2.6.5, and DCD Tier 2, Sections 9.4.1.1.2, 9.5.3.2.1, and 9.5.3.2.2. Therefore, Open Item 14.3.3-17 is resolved.

- Open Item 14.3.3-18: With regard to DCD Tier 1, Table 3.2-1, Item 10.i, DCD Tier 1, Section 2.7.1 does not have ITAAC related to RSR. In addition, there is no ITAAC that requires inspection, test, and analyses for the RSR and ventilation. The staff asked the applicant for clarification. This was Open Item 14.3.3-18 in the DSER.

  The applicant satisfactorily address this open item by making changes to DCD Tier 1, Section 2.7.1 and DCD Tier 1, Figure 2.7.1-1. Therefore, Open Item 14.3.3-18 is resolved.

- Confirmatory Item 14.3.3-1: The staff found typographical errors throughout the ITAAC. For example, the abbreviation, "HIS" should be replaced with "HSI." This was Confirmatory Item 14.3.3-1 in the DSER.

  The applicant satisfactorily addressed this confirmatory item by making the appropriate abbreviation changes. Therefore, Confirmatory Item 14.3.3-1 is resolved.

14.3.3.3 Piping Design

In the piping design area, the applicant used a different approach for AP1000 than it used in AP600. In AP600, the applicant essentially completed the piping design. The applicant developed the ITAAC for the AP600 design to provide reasonable assurance that the as-installed piping would meet its certified design requirements. Each AP600 system-based design description involving safety-related piping incorporated the ITAAC. However, for the AP1000, the applicant does not plan to complete the piping design prior to design certification. Instead, the applicant proposes to use DAC for piping design similar to their use in the evolutionary plants (i.e., ABWR and System 80+).

While piping DAC are established as a part of the certified plant design, the COL applicant will complete, in conjunction with its COL application, the overall piping design, including piping stress analyses, pipe support design, the effects of high-energy line breaks, and the application of leak-before-break (LBB). The COL applicant will also verify the piping design using ITAAC during plant construction. The as-built piping system is required, through the piping ITAAC, to be reconciled with the AP1000 design commitments. The applicant designated the supporting information for the piping DAC as Tier 2* information in the AP1000 Tier 2, information. Section 3.12 of this report discusses in detail the acceptability of the piping DAC, including the analysis methods and design criteria to be used by a COL applicant or licensee to complete the AP1000 piping design.

In SECY-02-0059, the staff identified an issue to the Commission regarding the applicant's proposed use of piping DAC, which differs from the approach used in previous design certification applications. The applicant proposed to provide, as part of a COL application that references the AP1000 design, its analyses for piping design using an LBB approach. In previous design certification reviews, the applicants provided, as a part of design certification, their bounding piping analyses in which an LBB approach was used. However, the applicant proposes to establish bounding curves at the design certification phase, and will provide an evaluation of LBB piping at the COL phase. This approach is not consistent with Commission policy. Without performing an evaluation of the LBB bounding curves using preliminary analysis results at the design certification stage, the question of whether sufficient margin exists in the piping to demonstrate that the probability of pipe rupture is extremely low would remain unresolved. Thus, the design certification review might not assure the finality of design. This was Open Item 14.3.3-19 in the DSER.

In Section 3.6.3.5 of this report, the staff discusses the applicant's revised approach that would provide reasonable assurance at the design certification stage that the LBB piping systems will have sufficient margin to meet the LBB bounding analysis curves (BACs) and, thus, ensure successful completion of the ITAAC at the COL stage. As discussed in Section 3.6.3.5 of this report, the applicant completed an LBB evaluation for a candidate AP1000 LBB piping system using AP1000 piping stress analysis results. The applicant also provided the staff with an assessment of the other LBB candidate piping subsystems that provided reasonable assurance that these other LBB candidate piping subsystems will be able to meet their respective BACs when the final piping design and stress analyses are completed by the COL applicant. The staff evaluated the preliminary piping design and LBB analyses performed by the applicant to address Open Item 3.6.3.4-2. The staff concludes, on the basis of these analyses and assessments, that the LBB piping systems contained sufficient margin to demonstrate that the ITAAC associated with LBB can be met at the COL stage. Thus, the probability of pipe ruptures for the AP1000 LBB candidate piping subsystems is extremely low under conditions consistent with the design bases for these piping subsystems (see Section 3.6.3.5 of this report). Therefore, as Open Item 3.6.3.4-2, which encompassed the staff's concern with the applicant's LBB approach, is resolved, Open Item 14.3.3-19, is also resolved.

The use of DAC for piping in the AP1000 does not affect the application of piping ITAAC because in either case (whether DAC is or is not used), completion of the piping design must occur prior to construction of the standard plant. The application of the piping ITAAC will occur after the piping design is completed. Each system-based design description involving safety-related piping also includes the piping ITAAC for the AP1000. The piping ITAAC for the AP1000 are the same as the piping ITAAC for the AP600. For the AP1000, Tier 1 piping DAC are described and repeated in each system where piping ITAAC apply. The first column of the ITAAC (i.e., design commitment) provides the Tier 1 piping DAC. The design commitments related to piping design include the following:

- The components identified in Table [w.x.y-z] as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

- Pressure boundary welds in piping identified in Table [w.x.y-z] as ASME Code Section III meet ASME Code Section III requirements.

- The components identified in Table [w.x.y-z] as ASME Code Section III retain their pressure boundary integrity at their design pressure.

- Each of the lines identified in Table [w.x.y-z] for which functional capability is necessary is designed to withstand combined normal and seismic design basis loads without a loss of functional capability.

- Each of the as-built lines identified in Table [w.x.y-z] as designed for LBB meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.

The above items are the piping design criteria appropriate as Tier 1 design commitments. The Tier 1 piping DAC address the piping design requirements in 10 CFR 50.55a and GDC 2 and 4 of Appendix A to 10 CFR Part 50. The acceptability of piping DAC is evaluated in Section 3.12 of this report.

14.3.4 Other Tier 1 Information

The applicant provided other Tier 1 information, such as definitions, general provisions, interface requirements, and site parameters. The evolutionary designs used similar information except for the basic configuration inspection (see discussion below). The applicant did not identify any significant interface requirements for the AP1000 design because of design features in the standard plant.

Both evolutionary designs used "verifications for basic configuration for systems." This verification process consisted of an inspection of the system functional arrangement in its final as-built condition at the plant site and included four other elements (e.g., dynamic and environmental qualification). The applicant adopted a "functional arrangement" inspection but assigned verification of the other four elements to individual ITAAC, as appropriate. For the evolutionary and AP600 designs, this functional arrangement inspection verifies that the as-built facility conforms to the approved design and applicable regulations by using as-built drawings, design documentation, and in situ plant walkdowns. The applicant's approach meets the intent of the basic configuration ITAAC, as described in Appendix D to draft SRP 14.3, because the four elements are verified in the individual ITAAC. Therefore, the staff finds it to be acceptable.

Many of the acceptance criteria in the ITAAC tables use the phrase "A report exists and concludes that ..." When this phrase was used for the evolutionary designs, a description of the report was provided in the Tier 2 information. Westinghouse has adopted a broader usage of this phrase and agreed, in a public meeting on July 10, 2003, to provide an explanation of its usage in the General Provisions section of Tier 1. Also, many entries in the inspections, tests, analyses column of the ITAAC tables use the phrase "Inspection will be performed for the existence of a report ... "In a telephone conference call held on August 19, 2003, Westinghouse agreed to provide an explanation of this phrase in the General Provisions section of Tier 1. Finally, during the same conference call, the NRC staff stated that "many ITAAC are only a reference to another Tier 1 location." The applicant agreed to provide an explanation of the phrase "See Tier 1 Material ... "in the General Provisions section of Tier 1. The staff has reviewed all of the additional explanations provided in a revision to the General Provisions section of DCD Tier 1, found that they adequately explain how to use the AP1000 ITAAC and are, therefore, acceptable.

Initially, control room relative concentration (χ/Q) values were not provided in DCD Tier 1, Table 5.0-1. As noted in Section 2.3.4 of this report, the COL applicant would have to assess the impact of design-specific information on the control room χ/Q values. This was Open Item 14.3.4-1 in the DSER.

Following discussions between the NRC staff and the AP1000 applicant, the control room χ/Q values were provided in DCD Tier 2, Tables 2-1 and 15A-6, and DCD Tier 1, Table 5.0-1, as well as design-specific information in DCD Tier 2, Table 15A-7 and Figure 15A-1. The information provided by the applicant addresses the issues raised by the staff. Therefore, Open Item 14.3.4-1 is resolved.

14.4 Combined License Applicant Responsibilities

In DCD Tier 2, Section 14.4, "Combined License Applicant Responsibilities," Westinghouse describes the following COL action items (note that the NRC staff action item number follows each Westinghouse item):

- The specific staff, staff responsibilities, authorities and personnel qualifications for performing the AP1000 initial test program are the responsibility of the Combined License applicant. This test organization is responsible for the planning, executing, and documenting of the plant initial testing and related activities that occur between the completion of plant/system/component construction and commencement of plant commercial operation. Transfer and retention of experience and knowledge gained during initial testing for the subsequent commercial operation of the plant is an objective of the test program. [This is COL Action Item 14.4-1.]

- The Combined License applicant is responsible for providing test specifications and test procedures for the preoperational and startup tests, as identified in [DCD Tier 2, Section] 14.2.3, for review by the NRC. [This is COL Action Item 14.4-2.]

- The Combined License application is responsible for a startup administration manual (procedure) which contains the administration procedures and requirements that govern the activities associated with the plant initial test program, as identified in [DCD Tier 2, Section] 14.2.3. [This is COL Action Item 14.4-3.]

- The Combined License applicant or holder is responsible for review and evaluation of individual test results. Test exceptions or results which do not meet acceptance criteria are identified to the affected and responsible design organizations, and corrective actions and retests, as required, are performed. [This is COL Action Item 14.4-4.]

- The Combined License applicant is responsible for testing that may be required of structures and systems which are outside the scope of the design certification. The interfacing systems to be considered for testing are taken from [DCD Tier 2,] Table 1.8-1 and include as a minimum, the following:

- storm drains
- site specific seismic monitors
- offsite ac power systems
- circulating water heat sink
- raw and sanitary water systems
- individual equipment associated with the fire brigade
- portable personnel monitors and radiation survey instruments
- equipment associated with the physical security plan

[This is COL Action Item 14.4-5.]

- [*The COL applicant or holder for the first plant and the first three plants will perform the tests listed in [DCD Tier 2, Section] 14.2.5. For subsequent plants, the COL applicant or licensee shall either perform the tests listed in [DCD Tier 2, Section] 14.2.5, or shall provide a justification that the results of the first-plant-only tests or first-three-plant tests are applicable to the subsequent plant.*]* [This is COL Action Item 14.4-6.]

15. TRANSIENT AND ACCIDENT ANALYSES

15.1 Introduction

In the AP1000 Design Control Document (DCD) Tier 2, Chapter 15, "Accident Analyses," the applicant discussed the analysis of various design-basis transients and accidents. The applicant used the results of these analyses in the DCD to show the conformance of the AP1000 advanced passive plant design with General Design Criterion (GDC) 10, "Reactor Design," for fuel design limits, GDC 15, "Reactor Coolant System Design," for the reactor coolant pressure boundary (RCPB) pressure limits, and the requirements of Title 10, Section 50.46, of the Code of Federal Regulations (10 CFR 50.46) for the performance of the emergency core cooling system (ECCS).

The staff of the U.S. Nuclear Regulatory Commission (NRC) has reviewed the AP1000 transient and accident analyses in the DCD, in accordance with Chapter 15, "Accident Analysis," of NUREG-0800, which defines the agency's Standard Review Plan (SRP).

15.1.1 Event Categorization

The applicant assigned the initiating events to the following categories, in accordance with Chapter 15 of the SRP and Regulatory Guide (RG) 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Plants:"

- increase in heat removal from the primary system
- decrease in heat removal by the secondary system
- decrease in reactor coolant system (RCS) flow rate
- reactivity and power distribution anomalies
- *increase in reactor coolant inventory*
- decrease in reactor coolant inventory
- anticipated transients without scram (ATWSs)

The first category, an increase in heat removal from the primary system, includes a new event involving inadvertent operation of the passive residual heat removal (PRHR) heat exchanger (HX). Because this category is broader than the category of increase in heat removal from the primary system in the SRP and RG 1.70 and reflects the AP1000 design, it is acceptable.

The applicant also grouped the design-basis events according to their anticipated frequency of occurrence, identified as Condition I—normal operation and operational transients, Condition II—faults of moderate frequency, Condition III—infrequent faults, and Condition IV—limiting faults. The applicant's event frequency grouping is consistent with the guidelines of RG 1.70 and the criteria of American Nuclear Society (ANS) 18.2-1973, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants." Condition I events occur frequently, and their effects on the consequences of Conditions II, III, and IV events should be considered. Condition II events may occur during a calendar year for a particular plant. Condition III events may occur infrequently during the life of a particular plant. Condition IV events are postulated but not expected to occur during the life of a plant.

The SRP divides the events into anticipated operational occurrences (AOOs) and postulated accidents. The requirements of 10 CFR Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," define AOOs as conditions of normal operation and those transients that are expected to occur one or more times during the life of a plant; therefore, AOOs encompass the normal, moderate-frequency and infrequent events of Conditions I through III. Chapter 15 of the SRP does not specify a category of infrequent incidents but does provide specific acceptance criteria for those events that cannot be categorized as infrequent. Thus, the event frequency categorization in the DCD is consistent with the NRC's licensing approach.

In DCD Tier 2, Section 15.0.1, the applicant listed the design-basis events analyzed under Conditions II, III, and IV. These events are generally consistent with the current licensing practice. However, the DCD lists the complete loss of forced reactor coolant flow event and the single rod cluster control assembly (RCCA) withdrawal event at full-power conditions as Condition III—infrequent faults. The event categorization is inconsistent with SRP Sections 15.3.1 and 15.4.3, which classify the complete loss of RCS flow and the withdrawal of an RCCA as Condition II—moderate-frequency events, with the acceptance criterion that specifies no violation against the safety limit of the departure from nucleate boiling ratio (DNBR). Nonetheless, the applicant analyzed the complete loss of forced reactor coolant flow event, as presented in DCD Tier 2, Section 15.3.2, to satisfy the acceptance criteria for a Condition II event. Thus, the staff concludes that the applicant's approach for the analysis of the complete loss of reactor coolant flow event is acceptable.

Per WCAP-9272-A, "Westinghouse Reload Safety Evaluation Methodology," Westinghouse was previously allowed to classify the withdrawal of an RCCA event as a Condition III event for reactors that it manufactured because of the event's very low probability of occurrence. Because the manufacturer of the existing pressurized-water reactors (PWRs) also designed the AP1000 reactor, the applicant's classification of the withdrawal of an RCCA event as a Condition III event is consistent with the current licensing practices and, therefore, is acceptable.

15.1.2 Non-Safety-Related Systems Assumed in the Analysis

For the design-basis analysis, only safety-related systems or components can be used to mitigate the events. In Westinghouse letter ET-NRC-93-3804, dated January 22, 1993, the applicant responded to the staff's request for additional information (RAI) 440.31 for the AP600 review. The applicant stated that non-safety-related systems or components are assumed to be operational in the following situations:

(a) when assumption of a non-safety-related system results in a more limiting transient

(b) when a detectable and nonconsequential random, independent failure must occur in order to disable the system

(c) when non-safety-related components are used as backup protection

For the AP1000 design, Westinghouse applied, as indicated in DCD Tier 2, Chapter 15, the same approach as in the AP600 design, indicated above in the specified situations for non-safety-related systems or components to be used for the analyses of the design-basis events.

The assumption in Case (a) will result in a more limiting transient and, therefore, it is acceptable.

For Case (b), the applicant assumed continued operation of the main feedwater control system (MFCS) in the design-basis analysis of those events not related to feedwater system malfunction, loss of alternating current (ac) power, or turbine trip. For example, an event involving withdrawal of an RCCA is analyzed from an at-power condition. Before the initiating fault causing the RCCA withdrawal, the MFCS should operate and maintain steam generator (SG) inventory. If a failure exists in the MFCS, alarms in the control room or abnormal control system performance should detect it before the start of the RCCA withdrawal event. The staff concludes that the assumption of MFCS continued operation is acceptable because a failure in the MFCS is not a consequence of the initiating event, and the probability of a random, independent failure occurring in the MFCS within the timeframe of the initiating event is extremely low.

For Case (c), as discussed in the response to RAI 440.061 and summarized in DCD Tier 2, Table 15.0-8, the applicant credited the following non-safety-related components as backup protection in the design-basis analysis for the AP1000 design:

- the main feedwater pump trip in the analysis of an increased feedwater flow event

- the pressurizer heater block in the analysis of loss of normal feedwater (LONF), inadvertent operation of core makeup tanks (CMTs), chemical and volume control system (CVCS) malfunction that increases reactor coolant inventory, steam generator tube rupture (SGTR), and small-break loss-of-coolant accidents (SBLOCA)

- main steam isolation valve (MSIV) backup valves (including the turbine stop, control valves, turbine bypass valves, moisture separator reheat steam supply control valve, and main steam branch isolation valves in the analysis of inadvertent opening of SG safety valves, steamline break (SLB), and SGTR events)

During the course of the review, the staff asked the applicant to address its compliance with 10 CFR 50.36, which specifies the criteria for the systems that are subject to technical specification (TS) limiting conditions for operation (LCOs). Specifically, 10 CFR 50.36(c)(2)(ii)(C) requires that a TS be established for a structure, system, or component (SSC) that is assumed to function or actuate in a design-basis analysis for the mitigation of specified events. In its response to RAI 440.061, the applicant indicated that it complied with the 10 CFR 50.36 requirements by providing TSs to include non-safety-related systems that are credited as backup systems in the licensing design-basis analyses. Items 7 and 27 of AP1000 TS Table 3.3.2-1, "Engineering Safeguards Actuation System Instrumentation," include applicable modes, surveillance requirements (SRs), and trip setpoints for the main feedwater pump trip and pressurizer heater trip, respectively. Section 3.7.2 of the AP1000 TS provides the LCOs for the main steam branch isolation valves and the MSIV backup valves. These TSs ensure the reliability of the non-safety-related components credited as backup systems in the design-basis analyses. Therefore, Section 3.7.2 of the AP1000 TS is acceptable.

Based on its review, the staff concludes that crediting these non-safety-related backup protection systems and components in the design-basis analyses is acceptable for the following reasons:

- The trip mechanisms of the feedwater pump trip breakers and pressurizer heater trip breakers are simple, and the likelihood of the breaker function failure is low.

- The operating data show that the turbine stop and control valves are reliable, and taking credit for the turbine valves in the design-basis analyses for backup protection is consistent with the staff position stated in NUREG-0138, "Staff Decision of Fifteen Technical Issues Listed in Attachment to November 3, 1976, Memorandum from Director, NRR to NRR Staff."

- The applicant has included SRs and LCOs in the TSs to ensure the reliability of the following systems or components:

  — feedwater pump trip breakers and redundant pressurizer heater trip breakers
  — MSIV backup valves and main steam branch isolation valves

15.1.3 Chapter 15 Loss of Offsite Power Assumptions

As indicated in DCD Tier 2, Section 15.0.14, the applicant performed the Chapter 15 analysis assuming a loss of offsite power (LOOP). The LOOP is not considered as a single failure, and the analysis is performed without changing the event category. The assumption of the LOOP in the Chapter 15 analysis complies with the requirements of GDC 17, "Electric Power Systems," of 10 CFR Part 50, Appendix A, which requires the analysis of AOOs and postulated accidents assuming a LOOP. In the analysis, a LOOP is considered a consequence of an event as a result of disruption of the grid following a turbine trip during the event.

In the case of events involving a turbine trip, the applicant assumed that a LOOP and the resulting coastdown of the reactor coolant pumps (RCPs) occurs 3 seconds after the turbine trip. DCD Tier 2, Section 8.2, provides the basis for the 3-second delay. That section describes the electrical design features of the AP1000, the electrical system response to a turbine trip, and the combined license (COL) applicant interfaces that support the 3-second assumption. Among others, the AP1000 design provisions include the following electrical features that support the 3-second delay:

- Use of an output generator circuit breaker and reverse power relay, with at least a 15-second delay before tripping the breaker following a turbine trip, allows the generator to provide voltage support to the grid and maintain adequate voltage to the RCPs for significantly longer than the assumed 3 seconds.

- The COL applicant interface item in DCD Tier 2, Table 1.8-1, Item 8.3 (that transient stability must be maintained and the RCP bus voltage must remain above the voltage required to maintain the flow assumed in Chapter 15 analyses for a minimum of 3 seconds following a turbine trip) ensures that, for the applicant's unique grid system configuration, a grid instability condition following a turbine trip will take at least 3 seconds before it results in a loss of power to the RCPs.

- The COL applicant interface item in DCD Tier 2, Table 1.8-1, Item 8.3, (that the protective devices controlling the switchyard breakers are set with consideration for preserving the plant grid connection following a turbine trip) is especially important in generator output circuit breaker designs to ensure that the opening of the switchyard breakers following a turbine trip does not interrupt the backfeed offsite circuit through the generator main stepup transformer.

- This design does not use automatic transfers of RCP buses, which precludes bus transfer failures following a turbine trip.

- If a turbine trip occurs when the grid is not connected to the plant, the main generator will be available to power the RCPs for at least 3 seconds before the generator output breaker is tripped on generator undervoltage or exciter overcurrent.

The staff has reviewed the information on the AP1000 electrical design, as well as the COL requirements. On that basis, and as described above, the staff has reasonable assurance that the RCPs can receive power for a minimum of 3 seconds following a turbine trip (discussed in Section 8.2.3.4 of this report). The staff has also reviewed the DCD Tier 2, Chapter 15, analysis and found that the applicant considered LOOP in all of the applicable analyzed events and applied the acceptance criteria specified in the related SRP sections for events with and without LOOP. Therefore, the staff concludes that the applicant's approach is acceptable.

15.1.4 Analytical Methods

The analytical methods used for transient and accident analyses are normally reviewed on a generic basis. As indicated in DCD Tier 2, Sections 15.0.11, 15.6.5.4A, and 15.6.5.4B, the methods used for transient and accident analyses include the following computer codes:

- TWINKLE—This multidimensional spatial neutronics code uses an implicit finite-difference method to solve the two-group transient neutronics equations in one, two, and three dimensions. TWINKLE has been used to calculate the kinetic response of a reactor for transients, such as the RCCA bank withdrawal from subcritical conditions and RCCA ejection events, which cause a major perturbation in the spatial neutron flux distribution. As documented in WCAP-7979-P-A (proprietary) and WCAP-8028-NP-A (nonproprietary), "TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code," issued January 1975, the NRC has approved this code for operating Westinghouse plants and the AP600. Since the AP1000 fuel design is similar to that of operating Westinghouse plants and the AP600 (i.e., falls within the NRC-approved applicable range of the code), the application of the TWINKLE code to the AP1000 for analysis of kinetic responses is acceptable.

- VIPRE-01—As documented in WCAP-14565-P-A (proprietary), and WCAP-15306-NP-A (nonproprietary), "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," issued October 1999, the NRC has approved this code for the core thermal-hydraulic (T-H) analyses, determining coolant density, mass velocity, enthalpy, vapor void, static pressure, and the DNBR distribution along parallel flow channels within the reactor core under normal operational and transient conditions. Since the AP1000 core design is similar to that of operating Westinghouse plants and the AP600 (i.e., falls within the NRC-approved applicable range of the code), the application of the VIPRE-01 code to the AP1000 T-H calculations is acceptable.

- COAST—As documented in CENPD-98-A, "Coast - Code Description," issued April 1973, the NRC has approved this code for use in calculating the reactor coolant flow coast transient for any combination of active and inactive RCPs and forward and reverse flow in the hot- or cold-legs. The NRC approved the code for the PWRs manufactured by the former Combustion Engineering (CE) (now merged as part of Westinghouse). The COAST code uses equations of conservation of momentum formulated for each of the flowpaths of the COAST model, assuming unsteady-state, one-dimensional flow of an incompressible fluid. The equation of conservation of mass is formulated for each nodal point. Pressure losses resulting from friction and geometric losses are assumed proportional to the square of the flow velocity. RCP dynamics are modeled using a head-flow curve for a pump at full speed and using four-quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed. The COAST code is a generic code for calculating the coastdown flow with the values of pump head curves and the pressure drop coefficients of the RCS components as the input parameters. Since the pump head curves and pressure loss coefficients used in the COAST code reflect the AP1000 design, the staff concludes that the use of COAST is acceptable for the AP1000 in calculating the RCP flow during the RCP coastdown transient.

- FACTRAN—As documented in WCAP-7908-A (nonproprietary), "FACTRAN - A FORTRAN-IV code for Thermal Transients in a UO2 Fuel Rod," issued June 1972, the NRC has approved the FACTRAN code for calculations of the transient heat flux at the surface of a rod. Since the AP1000 fuel rod design is similar to that of operating Westinghouse plants and the AP600 (i.e., falls within the NRC-approved applicable range of the code), the application of FACTRAN to the AP1000 heat flux calculations is acceptable.

- LOFTRAN—As documented in WCAP-7907-P-A (proprietary) and WCAP-7907-NP-A (nonproprietary), "LOFTRAN Code Description," issued April 1984, the NRC previously approved this code to allow Westinghouse to analyze system responses to non-LOCA events for conventional Westinghouse PWRs. LOFTRAN simulates a multiloop system using a model containing a reactor vessel (RV), hot- and cold-leg piping, SGs, and a pressurizer. The code also includes a point kinetics model, including reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the SG uses a homogeneous, saturated mixture for analyses of thermal transients and a water-level correlation for indication and control. When the applicant applied the LOFTRAN code to the AP600 safety analysis, it modified the code to incorporate features representative of the AP600 design which are important to modeling the non-LOCA transient analyses. WCAP-14234, "LOFTRAN and LOFTTR2 AP600 Code Applicability Document," issued June 1997, describes the LOFTRAN modifications. WCAP-14307, "AP600 LOFTRAN-AP and LOFTTR2-AP Final Verification and Validation Report," issued August 1997, documents the test data comparisons that support the LOFTRAN modifications.

- LOFTTR2—As documented in WCAP-10698-P-A (proprietary) and WCAP-10750-NP-A (nonproprietary), "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," issued August 1985, the NRC-approved code is used to analyze an SGTR event for conventional Westinghouse PWRs. LOFTTR2 is a modified version of LOFTRAN with a more realistic breakflow model, a two-region SG secondary side, and an improved capability to simulate operator actions during an SGTR event. The version of LOFTTR2 applied to the AP600 SGTR analysis incorporated the LOFTRAN changes to simulate passive safety features for the AP600 design. WCAP-14234 documents these changes.

- NOTRUMP—This code consists of the modeling features that meet the requirements of Appendix K to 10 CFR Part 50. As documented in WCAP-10079-P-A (proprietary), "NOTRUMP—A Nodal Transient Small Break and General Network Code," issued August 1985, and WCAP-10054-P-A (proprietary), "Westinghouse Small-Break ECCS Evaluation Model Using the NOTRUMP Code," issued August 1985, the NRC previously approved the NOTRUMP code for the SBLOCA analysis. WCAP-14807, Revision 5, "NOTRUMP Final Validation Report for AP600," issued August 1998, documents the modified version of the NOTRUMP code for the AP600 application.

- WCOBRA/TRAC-LBLOCA—As documented in WCAP-12945-P, Revision 2, "Code Qualification Document for Best Estimate LOCA Analysis," Volumes 1 through 5, issued March 1998, the NRC has approved this best estimate (BE) code in a safety evaluation dated June 28, 1996, for large-break loss-of-coolant accident (LBLOCA) analysis. WCAP-14171, Revision 2, "WCOBRA/TRAC Applicability to AP600 Large-Break Loss-of-Coolant Accident," issued March 1998, documents the modified version of the WCOBRA/TRAC code for the AP600 application. Westinghouse letter NSD-NRC-97-5171 dated June 10, 1997, documents its auxiliary code, HOTSPOT, which is updated for the AP600.

- WCOBRA/TRAC-LTC and WGOTHIC—WCOBRA/TRAC is also used for the post-LOCA long-term cooling (LTC) analyses. WCAP-14776, Revision 4, "WCOBRA/TRAC, OSU Long-Term Cooling Final Validation Report," issued March 1998, documents the code verification for the LTC analyses. The WGOTHIC code, documented in WCAP-14407, Revision 3, "WGOTHIC Application to AP600," issued April 1998, is used to calculate containment boundary conditions for LBLOCA and post-LOCA LTC. The staff previously reviewed and accepted the application of WCOBRA/TRAC and WGOTHIC for LTC calculations, as discussed in Chapter 21 of this report.

In support of the AP1000 application, the applicant submitted WCAP-15644-P, "AP1000 Code Applicability Report," issued March 2004, for the staff to review. WCAP-15644-P documents the applicant's assessment of the safety analysis codes that were developed and approved for the AP600 design certification to determine their applicability for use in the AP1000 design. The safety analysis codes include LOFTRAN, LOFTTR2, NOTRUMP, WCOBRA/TRAC, and WGOTHIC. The staff reviewed the report and concluded in a March 25, 2002, letter from J.E. Lyons (NRC) to W.E. Cummins (Westinghouse), "Applicability of AP600 Standard Plant Design Analysis Codes, Test Program and Exemptions to the AP1000 Standard Plant Design," that the modified LOFTRAN and LOFTTR2 codes are acceptable for use in the AP1000 analysis with the following conditions and limitations:

- Table 2 of the enclosure to the March 25, 2002, letter listed the transients and accidents that Westinghouse proposed to analyze with the LOFTRAN code. The staff limited its review of LOFTRAN usage by Westinghouse to this set. The use of the code for other analytical purposes will require additional justification.

- In the preapplication review, the staff requested that Westinghouse perform main steamline break (MSLB) analyses for the AP1000 standard plant design. In particular, the staff wanted to assess the ability of the code to model the resulting steam formation in the reactor coolant loops. The applicant has provided this analysis. Chapter 21 of this report includes a review of this material.

In addressing the staff's review question regarding compliance with the limitations imposed by the staff on the use of the LOFTRAN and LOFTTR2 codes, the applicant provided its response to RAI 440.054 and indicated that the codes are used only for those events identified in the NRC letter of March 25, 2002. The applicant has submitted the MSLB analysis in DCD Tier 2, Section 15.1.5. The analysis results demonstrate that voiding in the reactor coolant loops does not occur and, therefore, is not a concern for the MSLB event. Because the application of LOFTRAN and LOFTTR2 in the safety analysis for the AP1000 has complied with the limitations imposed by the NRC staff, the staff concludes that the application is acceptable.

The applicant also provided the assessment addressing the applicability of NOTRUMP, WCOBRA/TRAC, and WGOTHIC to the safety analysis for the AP1000 design. The staff has reviewed the applicant's compliance assessment and documented its evaluation in Section 21.6.2 of this report for NOTRUMP, Sections 21.6.3 and 21.6.4 of this report for WCOBRA/TRAC, and Section 21.6.5 of this report for WGOTHIC.

15.1.5 Steam Generator Middeck Plate Induced Level Measurement Uncertainty

Westinghouse has issued three Nuclear Service Advisory Letters (NSALs), NSAL-02-3 and Revision 1, NSAL-02-4, and NSAL-02-5, which document the concerns with the Westinghouse-designed SG water-level setpoint uncertainties. NSAL-02-3 and its revision, dated February 15 and April 8, 2002, respectively, deal with the uncertainties in the SG water-level measurement caused by the placement of the middeck plate between the upper and lower taps. These uncertainties affect the low-low level trip setpoint (used in the analysis for events such as the feedwater line break (FLB), ATWS, and SLB). NSAL-02-4, dated February 19, 2002, deals with the uncertainties in the measurement created because the calculation does not reflect the void content of the two-phase mixture above the middeck plate. These uncertainties affect the high-high level trip setpoint. NSAL-02-5, dated February 19, 2002, deals with potential inaccuracies in the initial conditions assumed in safety analyses affected by SG water level. The safety analyses may not be bounding because the velocity head under some conditions may increase the uncertainties in the SG water-level control system. The staff requested, via RAI 440.062, the applicant to discuss (1) the AP1000 design that accounts for all the uncertainties documented in these advisory letters in determining the SG water-level setpoints, and (2) the effects of the water-level uncertainties on the analyses of the LOCA and non-LOCA transients and the ATWS event.

The applicant's response to RAI 440.062 stated that measurement uncertainties for the reactor protective system and engineered safety feature (ESF) actuation system instrumentation can be determined only when actual instrumentation is selected for the plant. The plant-specific setpoint calculations will be completed and reviewed as part of the COL. The COL applicants referencing the AP1000 certified design will provide a calculation of setpoints for protective functions consistent with the methodology discussed in WCAP-14605, "Westinghouse Setpoint Methodology for Protective Systems—AP600," issued April 1996. The methodology can be used for performing setpoint studies independent of the hardware used for the protection system, and, therefore applies to the AP1000 design. The setpoint study will include applicable uncertainties discussed in the referenced NSALs. Using the methodology in WCAP-14605, plant nominal setpoints are calculated by adding the channel allowance from the setpoint study to the setpoints used in the safety analysis.

The COL applicant should evaluate and confirm the validity of the safety analysis documented in the DCD using plant-specific setpoints and instrument uncertainties, including the SG middeck-level measurement uncertainty. The COL applicants should submit in the plant-specific applications the setpoint analysis and the associated safety analysis for the staff to review and approve. This item was designated as draft safety evaluation report (DSER) Open Item 15.1.5-1. In addressing DSER Open Item 15.1.5-1, Westinghouse provided its response in a letter from M.M. Corletti (Westinghouse) to the NRC dated July 1, 2003, "Transmittal of Westinghouse Responses to Open Items Identified in the AP1000 Draft Safety Evaluation Report." In the response, Westinghouse indicated that Item E of Revision 1 to RAI 440.002 addressed the COL information in DCD Tier 2, Section 7.1.6, related to instrumentation setpoint uncertainty calculations by the COL applicant upon selection of the installed plant instrumentation. In accordance with the current practice, the safety analyses will become plant specific when the COL applicant performs the setpoint study to develop plant-specific TS setpoints based on the safety analysis values, adding instrumentation uncertainty, as well as uncertainties related to the effects of the SG middeck plate on SG-level measurement. The TS setpoints are changed to reflect instrumentation uncertainties. Westinghouse stated, and the staff agreed, that the plant safety analyses are not changed because the revised TS setpoints are based on the safety analyses documented in the DCD. The COL actions to establish appropriate plant-specific setpoints, as discussed in DCD Tier 2, Section 7.1.6, add the appropriate plant-specific values to the TS setpoints used in the safety analyses. Therefore, the staff concludes that no other COL action is needed to reperform any safety analyses, and DSER Open Item 15.1.5-1 is resolved. This is COL Action Item 15.1.5-1.

15.2 Transient and Accident Analysis

The applicant presents the results of transient and accident analysis for the AP1000 design in DCD Tier 2, Chapter 15. This section discusses the staff's evaluation of results of the analysis and the applicant's responses to the staff's RAIs. Section 15.3 of this report presents the staff's evaluation of the analysis for radiological releases.

15.2.1 Increase in Heat Removal from the Primary System

In DCD Tier 2, Section 15.1, the applicant presented the results of its analysis of the events involving an increase in heat removal from the primary system. The events include (1) feedwater system malfunctions causing a reduction in feedwater temperature, (2) feedwater system malfunctions causing an increase in feedwater flow, (3) excess increase in secondary steam flow, (4) inadvertent opening of an SG relief or safety valve, (5) SLB, and (6) inadvertent operation of the PRHR HX. The staff provides its evaluation of the analytical results in the following sections.

15.2.1.1 Decrease in Feedwater Temperature (DCD Tier 2, Section 15.1.1)

Failure of a low- or high-pressure heater train may cause a decrease in feedwater temperature, a moderate-frequency event. A reduction in feedwater temperature decreases reactor coolant temperature, which, in turn, causes an increase in core power because of the effects of the negative moderator coefficient of reactivity. Because the rate of energy change is reduced as load and feedwater flows decrease, the transient initiated from zero-power conditions is less severe than the full-power case. The applicant's analysis for the limiting case is based on initial full-power conditions with a decrease of feedwater temperature caused by the loss of one string of low-pressure feedwater heaters. The loss of a string of feedwater heaters results in a maximum reduction in feedwater temperature of 26.4 °C (79.5 °F). The applicant's analysis indicates that the decrease in feedwater temperature results in an increase in core power of less than 10 percent of full power. The decrease in feedwater temperature event is bounded by an excessive increase in secondary steam flow (a moderate-frequency event), which results in a power increase of 12 percent. Section 15.2.1.3 of this report discusses the staff's review of the event with an excessive increase in secondary steam flow.

15.2.1.2 Increase in Feedwater Flow (DCD Tier 2, Section 15.1.2)

Increase in feedwater flow events may be caused by system malfunctions or operator actions that result in an inadvertent opening of a feedwater control valve. The excessive feedwater flow reduces reactor coolant temperature, which, in turn, causes a power increase because of the effects of the negative moderator coefficient of reactivity. The SG high-2 water-level signal trip prevents the continuous addition of excessive feedwater by closing the feedwater isolation valves and feedwater control valves and trips the turbine, main feedwater pumps, and reactor.

The applicant uses three codes to perform the analysis for this event. LOFTRAN calculates the nuclear power transient, the RCS flow coastdown, and the primary pressure and temperature transient. FACTRAN calculates the heat flux based on the nuclear power and flow from

LOFTRAN. VIPRE-01 calculates the departure from DNBR during the transient, using the heat flux from FACTRAN and the flow from LOFTRAN.

The applicant analyzed both the no-load case and the full-power case. For the no-load condition, the applicant assumed a feedwater control valve malfunction resulting in a step increase to 120 percent of nominal feedwater flow to one SG. The applicant assumed a feedwater temperature at the low value of 4.4 °C (40 °F). With the plant at no-load conditions, the turbine is not connected to the grid. Any subsequent reactor or turbine trip will not disrupt the grid and produce a consequential LOOP. Therefore, the applicant did not assume a LOOP in the no-load case. The results of the analysis show that the no-load case is bounded by an uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition, because of a lower reactivity insertion rate than the uncontrolled RCCA bank withdrawal event stemming from the effects of the negative moderator coefficient of reactivity. Section 15.2.4.1 of this report provides the staff's review and approval of the analysis of an uncontrolled RCCA bank withdrawal event.

The applicant's analysis for the limiting case is based on initial full-power conditions with an increase of feedwater flow caused by malfunction of one feedwater control valve to its maximum capacity, resulting in a step increase to 120 percent of nominal feedwater flow to one SG. An SG high-2 level trip signal actuates a reactor trip and an associated turbine trip. In addressing the issue of a LOOP, the applicant assumed that a LOOP and the resulting coastdown of the RCPs occur 3 seconds after the turbine trip. As discussed in Section 15.1.3 of this report, the assumption of a LOOP with a delay time of 3 seconds is acceptable.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event. From the viewpoint of an SG overfilling, the worst case is a failure of the feedwater control valve in the affected SG to close, in combination with a single failure of the feedwater isolation valve to close. In this case, the applicant indicated in its response to RAI 440.063 that an SG high-2 level trip signal will trip feedwater pumps and terminate the excessive feedwater flow. The staff notes that the feedwater pumps trip is a non-safety-related system. The staff has reviewed and approved the use of the feedwater pumps trip to terminate the excessive feedwater flow, as discussed in *Section 15.1.2 of this report.*

The applicant performed the analysis using an acceptable method, and the results of the analysis demonstrate that the limiting full-power case meets the acceptance criteria for this moderate-frequency event. Specifically, the calculated peak RCS pressure falls below 110 percent of the RCS design pressure, and the calculated DNBRs for the transient remain above the safety limit DNBR defined in DCD Tier 2, Section 4.4. As a result, the analysis satisfies the acceptable criteria defined in SRP Section 15.1.2. Therefore, the staff concludes that the analysis is acceptable.

15.2.1.3 <u>Excessive Increase in Secondary Steam Flow (DCD Tier 2, Section 15.1.3)</u>

An operator action or an equipment malfunction in the steam dump control or turbine speed control may cause an excessive increase in secondary steam flow. A rapid increase in steam flow results in a power mismatch between the reactor core power and the SG load demand.

The applicant analyzed four cases involving a 10-percent step load increase from the rated load, using the previously approved LOFTRAN, FACTRAN, and VIPRE-01 codes and assuming the following for each case:

- Case 1—minimum moderator feedback and manual reactor control
- Case 2—maximum moderator feedback and manual reactor control
- Case 3—minimum moderator feedback and automatic reactor control
- Case 4—maximum moderator feedback and automatic reactor control

The 10-percent step load increase is the highest load increase allowed in the range of 25 to 100 percent of full power. Each case is analyzed without taking credit for pressurizer heaters. At the initiation of the event, the RCS pressure and temperature are assumed at their full-power values for the DNBR calculation. The safety DNBR limit, as described in WCAP-11397-P-A, "Revised Thermal Design Procedure," issued April 1989, includes uncertainties in initial conditions. In DCD Tier 2, Sections 15.1.4 and 15.1.5 analyze steam flow increases greater than 10 percent, and Sections 15.2.1.4 and 15.2.1.5 of this report evaluate them.

In demonstrating the capability of the plant for the cases with automatic rod control, the applicant took no credit for delta T trips on overpower and overtemperature. The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these systems or equipment will adversely affect the consequences of the event. In considering the effects of a LOOP, the applicant assumed a reactor trip with a coincident turbine trip followed by a LOOP 3 seconds later. The LOOP primarily causes the RCPs to coast down. Since the LOOP is delayed for 3 seconds after the turbine trip, the RCCAs are inserted well into the core before the RCS flow coastdown begins. The resulting power reduction compensates for the reduced flow encountered once the RCPs lose power. Therefore, the applicant's analysis indicates that the minimum DNBRs predicted during the event will occur before flow coastdown begins.

The results of the analysis show that the calculated peak RCS pressure is less than 110 percent of the design pressure, and the calculated minimum DNBR does not violate the safety DNBR limits. Because the analysis uses acceptable methods and the results meet the acceptance criteria of SRP Section 15.1.3 for this moderate-frequency event, the staff concludes that the analysis is acceptable.

15.2.1.4 <u>Inadvertent Opening of an SG Relief or Safety Valve (DCD Tier 2, Section 15.1.4)</u>

An inadvertent opening of an SG relief, safety, or steam dump valve may result in an increase in steam flow. In the presence of a negative moderator temperature coefficient (MTC), the excessive cooldown increases positive reactivity, which, in turn, increases the core power level.

In assessing the effects of the negative MTC, the applicant's analysis assumes the most negative MTC corresponding to the end-of-life rodded core with the most reactive RCCA in its fully withdrawn position. Availability of offsite power is assumed to maximize the cooldown effect. Because the initial SG water inventory for the no-load case is greater, the magnitude and duration of the RCS cooldown resulting from steam releases is greater, and the associated positive reactivity addition is, therefore, also greater. Consequently, the applicant has determined that zero-power conditions are more limiting than at-power conditions for this postulated event. Because the turbine is initially in the trip condition for the plant at zero power, the consequential LOOP following the turbine trip is not considered a credible event and, therefore, is not modeled in the analysis.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event. It identified the limiting single failure as a failure of one CMT discharge valve to open. The applicant also made the following assumptions to maximize the cooldown effects:

- A typical capacity steam flow rate of 236 kilograms per second (kg/s) at 8.2 MegaPascals (MPa) (520 pounds mass per second (lbm/s) at 1200 pounds per square inch absolute (psia)) for any single steam dump, relief, or safety valve is assumed as the initial steam flow.
- The Moody model, without consideration of the piping friction losses, is used to calculate the steam flow.
- The most reactive RCCA is assumed to be stuck out of the core after the reactor trip.
- The lowest startup feedwater temperature is assumed.
- Four RCPs are assumed to be operating initially.
- No moisture is assumed in the blowdown steam.
- Manual actuation of the PRHR system is assumed at the initiation of the event.

The applicant used the LOFTRAN code to analyze the event. During the transient, the low cold-leg temperature "S" signal automatically actuates the CMT injection and the associated tripping of the RCPs. Boron solution at 3400 parts per million (ppm) enters the RCS, providing negative reactivity to prevent a significant return to power and core damage. Later in the transient, as the reactor pressure continues to decrease, accumulators actuate and inject boron solution at 2600 ppm.

The results of the analysis show that the RCS pressure remains below 110 percent of the design pressure, and the departure from nucleate boiling (DNB) does not occur, thereby satisfying the acceptance criteria in SRP Section 15.1.4. Therefore, the staff concludes that the analysis is acceptable.

15.2.1.5 Steam System Piping Failure (DCD Tier 2, Section 15.1.5)

An SLB, a limiting-fault event, is defined as a pipe break in the main steam system. The steam release during an SLB causes a decrease in the RCS temperature and SG pressure. In the presence of a negative MTC, the RCS temperature decrease results in an addition of positive reactivity, which increases the core power level. The SG pressure decrease initiates a reactor trip when low pressure in the steam system produces a safeguards "S" signal. The "S" signal initiates the actuation of the CMTs, which, in turn, initiates a trip of the RCPs. In addition, the "S" signal isolates all feedwater control and isolation valves and trips the main feedwater pumps. The low cold-leg temperature signal isolates the startup feedwater control and isolation valves. Ultimately, the borated water from the CMTs shuts down the reactor.

The applicant used the LOFTRAN code to calculate the system transient and the VIPRE-01 code to determine whether DNB had occurred for the core transient conditions calculated by the LOFTRAN code. The applicant analyzed a double-ended rupture at no-load conditions with no decay heat as the limiting case. Because the SGs have integral flow restrictors with a 0.13 square meter $(m)^2$ (1.4 square feet $(ft)^2$) throat area, any rupture with a break greater than 0.13 m^2 (1.4 ft^2), regardless of location, will have the same effect on the system as a 0.13 m^2 (1.4 ft^2) break; therefore, the analysis assumes this limiting break area.

Because the average coolant temperature for a core tripped from at-power conditions is higher than at no-load conditions, and energy is stored in the fuel, the RCS for a core tripped from at-power conditions contains more stored energy than at no-load conditions. The additional stored energy reduces the cooldown caused by the SLB. Therefore, no-load conditions are more limiting than at-power conditions. To represent the limiting initial conditions and maximize the cooldown effect, the applicant assumed an initial condition for the SLB analysis of zero power with no stored energy in the fuel.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event. For an SLB in which a single failure results in the failure of the MSIV in the intact SG to close, the applicant took credit for closing the non-safety-related MSIV backup valves (including the turbine-isolation and control valves) to avoid an uncontrolled blowdown from two SGs. The use of the MSIV backup valves in the SLB analysis for backup protection is acceptable, as discussed in Section 15.1.2 of this report. In addition, in order to maximize the overcooling effect, the applicant made the following assumptions:

- The most reactive RCCA is in the fully withdrawn position after reactor trip.
- The end-of-life shutdown margin at zero power is assumed when the accident is initiated.
- A negative moderator coefficient is assumed for the end-of-life rodded core with the most reactive RCCA stuck out.
- The Moody model without consideration of the piping friction losses, maximizing the blowdown flow rate, is used to calculate the steam flow.
- The maximum cold startup feedwater flow, plus nominal 100-percent main feedwater, is assumed.
- Four RCPs are assumed to be operating initially.

- No moisture is assumed in the blowdown steam.

- Manual actuation of the PRHR system is assumed at the initiation of the event to maximize the cooldown.

Availability of offsite power is assumed to maximize the cooldown effect. The results of an SLB with offsite power available bound the case with a LOOP for the following reasons:

- The initial condition of a LOOP results in an immediate RCP coastdown, which reduces the RCS cooldown effect and the magnitude of the return-to-power by reducing primary-to-secondary heat transfer.

- During the SLB event, actuation of the CMTs will provide borated water that injects into the RCS. Flow from the CMTs increases if the RCPs have coasted down. Therefore, the analysis performed with offsite power and continued RCP operation reduces the rate of boron injection into the core, which increases the potential for the core to return to criticality after reactor trip.

- The plant protection system automatically provides a safety-related signal that initiates the coastdown of the RCPs coincident with CMT actuation. Because this RCP coastdown initiates early during the SLB event, the difference is insignificant in predicting the DNBRs for cases with and without offsite power.

- Because of the passive nature of the safety injection system, the LOOP will not delay the actuation of the safety injection system.

During the event, the reactor protection system initiates a trip of the RCPs in conjunction with actuation of the CMTs. The MSIVs fully close in less than 10 seconds from receipt of a closure signal.

In response to RAI 440.067, which addresses the staff's concern regarding the effect of the timing of a LOOP on the analysis of the limiting SLB case, the applicant analyzed two full-break SLB cases initiated with the reactor at no-load conditions, one with offsite power available throughout the event, and one with offsite power loss simultaneous with the SLB at the start of the event. The SLB analysis shows that for the case with LOOP, the RCPs begin coasting down at the initiation of the transient, and, for the case with offsite power available, the protection system automatically trips the RCPs at 7.4 seconds into the transient. The results of the analysis show that the small difference in timing of the initiation of the RCP coastdown has no significant impact on the parameters that affect the return to power. The calculated peak core heat flux for the case with offsite power available was slightly greater than that for the LOOP case (3.17 percent versus 3.14 percent of the nominal full-power value). Consistent with the results presented in the DCD, this SLB analysis confirms that the SLB event initiated from the no-load conditions with offsite power available bounds the case with a LOOP initiated at time zero, and the event is a limiting case.

The staff concludes that the analysis for postulated SLBs is acceptable for the following reasons:

- The applicant has used the LOFTRAN code for the system response determination and the VIPRE-01 code for the DNBR calculations in the analysis for an SLB event. Throughout the event, the RCS temperature remains below saturated temperatures, confirming that the SLB analysis falls within the applicable range of the LOFTRAN code (also discussed in Section 15.1.4 of this report).

- The values used for input parameters, resulting in a maximum cooldown effect and the greatest potential for fuel failure, are conservative.

- The results of the SLB analysis have shown that the minimum DNBR remains above the allowable safety limit DNBR, and the peak RCS pressure remains below 110 percent of the design pressure, thus satisfying the acceptance criteria of SRP Section 15.1.5 for an SLB analysis.

15.2.1.6 Inadvertent Operation of the PRHR (DCD Tier 2, Section 15.1.6)

The inadvertent actuation of the PRHR system may be caused by operator action or a false actuation signal that opens the valves that normally isolate the PRHR HX from the RCS. This moderate-frequency event causes an injection of relatively cold water into the RCS and results in the addition of positive reactivity in the presence of a negative MTC.

The applicant considered plant initial conditions at both full power and zero power. A comparative assessment shows that the analysis performed for the inadvertent opening of an SG relief- or safety-valve event (discussed in Section 15.2.1.4 of this report) bounds the zero-power condition. This occurs because the latter event, a moderate-frequency event, is analyzed assuming PRHR HX actuation coincident with SG depressurization. Therefore, the applicant's analysis for the limiting case is based on initial full-power conditions.

For this analysis, the applicant used LOFTRAN for the system response calculation, FACTRAN for the heat flux determination, and VIPRE-01 for the DNBR calculation and assumed a negative moderator coefficient for the end-of-life rodded core. The applicant generated the core properties used in the LOFTRAN code for reactivity feedback calculations by combining those in the sector with cold coolant nearest to the loop with the PRHR system with those associated with the remaining sector. Control systems are assumed to function only when their operation results in more severe conditions. The analysis considered cases both with and without automatic rod control. The reactor trips on high neutron flux, and the analysis does not credit overtemperature and overpower delta T trips.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these systems or equipment will adversely affect the consequences of the event.

In considering the effects of a LOOP, the applicant assumed that a reactor trip and an associated turbine trip occur at the time of peak power. A loss of power is assumed to occur 3 seconds after the turbine trip. Since the LOOP is delayed for 3 seconds after the turbine trip, the RCCAs are inserted well into the core before the RCS flow coastdown begins. The resulting power reduction compensates for the reduced flow encountered once the RCPs lose power. The applicant's analysis indicates that the minimum DNBRs predicted during the event occur before flow coastdown begins. With the assumption of no reactor trip occurring during the transient, the results show that for the limiting case (the full-power case with manual rod control), the core power stabilizes at about 108 percent of its nominal value.

The staff finds that the assumptions used in the analysis are conservative for the reasons stated above and, therefore, are acceptable. The results of the analysis for the limiting full-power case with and without offsite power available show that the RCS pressure remains below 110 percent of the design pressure, and the minimum DNBR remains above the safety limit DNBR, thus satisfying the acceptance criteria of the SRP for moderate-frequency events. Therefore, the staff concludes that the analysis is acceptable.

15.2.2 Decrease in Heat Removal by the Secondary System (DCD Tier 2, Section 15.2)

The applicant has analyzed transients specified in SRP Section 15.2 for cases resulting from a decrease in heat removal by the secondary system and identified the limiting cases with regard to the capability of the RCS boundary and fuel rod cladding to withstand the consequences of transients. The transients include (1) steam pressure-regulator malfunction or failure resulting in decreasing steam flow, (2) loss of external electrical load, (3) turbine trip, (4) inadvertent closure of MSIVs, (5) loss of condenser vacuum and other events resulting in turbine trip, (6) loss of ac power to the station auxiliaries, (7) LONF flow, and (8) feedwater system pipe break. The staff has reviewed the applicant's analyses, as discussed in Sections 15.2.2.1 through 15.2.2.8 of this report.

15.2.2.1 Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow (DCD Tier 2, Section 15.2.1)

The AP1000 design includes no SG pressure regulators whose failure will cause a decreasing steam flow transient. Therefore, this event does not apply to the AP1000 design.

15.2.2.2 Loss of External Electrical Load (DCD Tier 2, Section 15.2.2)

Electrical system failures may cause the loss of external electrical load, a moderate-frequency event. Following the loss of generator load, an immediate fast closure of the turbine control valves will occur. A decrease in heat transfer capacity from primary to secondary causes the transient in primary pressure, temperature, and water volume because of a rapid decrease of steam flow to the turbine, accompanied by an automatic reduction of feedwater. Reactor trips on high pressurizer pressure, high pressurizer water-level, and overtemperature delta T signals protect the reactor. The pressurizer and the SG safety valves may lift to protect the RCS from overpressurization.

The turbine trip event bounds this loss of external electrical load event, because the turbine control valves close more slowly than the turbine stop valves close as a result of a turbine trip event. The smaller reduction in heat removal from a slower termination of steam flow will result in a lower peak RCS pressure. Section 15.2.2.3 below discusses the staff's evaluation of the turbine trip analyses.

15.2.2.3 Turbine Trip (DCD Tier 2, Section 15.2.3)

Signals, including generator trip, low condenser vacuum, loss of lubricating oil, turbine thrust bearing failure, turbine overspeed, manual trip, and reactor trip, may initiate the turbine trip event. Following a turbine trip, the turbine stop valves rapidly close, and steam flow to the turbine abruptly stops. The loss of steam flow results in a rapid increase in secondary system pressure and temperature, as well as a reduction of the heat transfer rate in the SGs, which, in turn, causes the RCS pressure and temperature to rise.

The applicant performed the analysis for this event using LOFTRAN for the transient response calculation, FACTRAN for the heat flux calculation, and VIPRE-01 for the DNBR calculation. In the DNBR determination, initial core power, RCS pressure, and RCS temperature are assumed to be at their nominal values consistent with steady-state, full-power operation. The DNBR limit includes uncertainties in initial conditions as described in WCAP-11397-P-A. In maximizing the RCS overpressurization effects, the turbine is assumed to trip without actuating the rapid power reduction system. This assumption delays the reactor trip until conditions in the RCS result in a trip actuated by other signals. The reactor is assumed to trip by the first reactor trip setpoint reached on high pressurizer pressure, overtemperature delta T, high pressurizer water-level, or low SG water-level trip signals. In addition, the analysis takes no credit for the turbine bypass system. Main feedwater is terminated at the time of turbine trip, with no credit taken for startup feedwater or the PRHR system to mitigate the consequences of the event. The availability of the pressurizer safety valves is assumed to reduce the pressure increase during the transient. In considering the effects of a LOOP, the applicant has assumed that offsite power will last for 3 seconds after the turbine trip. The applicant also has considered plant systems and equipment, as discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event and it determined that no single active failure in these systems or equipment would adversely affect the consequences of the event.

In analyzing the turbine trip event, the applicant considered both minimum and maximum reactivity feedback cases. The applicant also considered the event with and without credit for the effect of pressurizer spray in reducing the reactor coolant pressure. The applicant analyzed each case with and without offsite power available. The results of the applicant's analysis show that the most limiting case analyzed is a turbine trip from full power with minimum moderator feedback. The limiting case assumes no available offsite power and takes no credit for the effect of pressurizer spray in reducing the RCS pressure.

The staff finds that (1) the analysis used computer codes previously approved by the NRC and adequate assumptions to maximize the peak pressure, (2) the calculated peak RCS pressure for the limiting turbine trip case falls below 110 percent of the RCS design pressure, (3) pressurizer overfilling does not occur, and (4) the calculated minimum DNBR is within the safety DNBR limit, thus satisfying the acceptance criteria of SRP Section 15.2.3. Therefore, the staff concludes that the analysis is acceptable.

15.2.2.4 Inadvertent Closure of Main Steam Isolation Valves (DCD Tier 2, Section 15.2.4)

The inadvertent closure of steam isolation valves results in a turbine trip. The consequences of this event are the same as those of the turbine trip event discussed in Section 15.2.2.3 of this report.

15.2.2.5 Loss of Condenser Vacuum (DCD Tier 2, Section 15.2.5)

Loss of the condenser vacuum may result in a turbine trip and prevent steam from dumping to the condenser. Because the applicant assumes that the steam dump is unavailable in the turbine trip analysis, no additional adverse effects will result for the turbine trip event caused by the loss of the condenser vacuum. Therefore, the analytical results reviewed and discussed in Section 15.2.2.3 of this report for the turbine trip event also apply to the loss of condenser vacuum event.

15.2.2.6 Loss of AC Power to the Plant Auxiliaries (DCD Tier 2, Section 15.2.6)

A complete loss of the offsite grid, accompanied by a turbine-generator trip, may cause the loss of ac power, a moderate-frequency event. In terms of the removal of decay heat, this event is more severe than the turbine trip event because, for this event, an RCS flow coastdown accompanies the decrease in heat removal by the secondary system, which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip upon reaching one of the reactor trip setpoints in the primary and secondary systems as a result of the flow coastdown and decrease in secondary heat removal, or as a result of the loss of power to the control rod drive mechanisms.

The applicant used the LOFTRAN code to perform the RCS system response analysis following a plant LOOP. The analysis credits only safety-related systems to mitigate the consequences of the event. In the system response analysis, the initial reactor power is assumed to be 102 percent of the rated power level. The ANSI 5.1-1979, "Decay Heat Power in Light-Water Reactors," decay heat data represent the core residual heat generation rate. A LOOP is assumed to occur at the time of the reactor trip, which is actuated on a trip signal of Low narrow-range SG level. The assumption of a LOOP coincident with the reactor trip is more conservative than the case with the offsite power loss at time zero because of the lower SG water inventory for heat removal at the time of the reactor trip.

In addition, the PRHR HX heat transfer coefficients are assumed to be at low values associated with the low flow rate caused by the RCP trip. In RAI 440.074, the staff requested the applicant to justify the adequacy of the calculated PRHR heat transfer coefficients during the loss of ac power event. The applicant's response to RAI 440.074 stated that the determination of the PRHR heat transfer coefficients was based on the same methods discussed in Chapter 9 of WCAP-12980, Revision 3, "AP600 Passive Heat Removal Heat Exchanger Test Final Report," issued April 1997, which the NRC previously reviewed and approved, in a letter dated March 25, 2002, from J.E. Lyons (NRC) to W.E. Cummins (Westinghouse), for application to the AP1000 as part of the AP1000 preapplication review. In WCAP-12980, the results of calculations using the Dittus-Boelter correlation show that the predicted values reasonably agree with the PRHR test data. The operating conditions for the PRHR tests include 1.1 Lpm to 37.8 Lpm (0.3 gpm to 10.0 gpm) for the single HX tube flow, 121 °C to 343 °C (250 °F to 650 °F) for the primary temperature, and 0.446 MPa to 16.0 MPa (50 psig to 2300 psig) for the primary water pressure. The applicant calculated the PRHR tube flow and primary temperature during the loss of ac power event and showed that the flows and temperatures fall within the range of the PRHR test conditions. During the loss of ac power transient, the primary pressure increased from 15.5 MPa to 17.2 MPa (2250 psia to 2500 psia), which slightly exceeds the test range.

Because the primary-side fluid remains in single phase during a loss of ac power event, the applicant indicated that the impact of pressure on the primary heat transfer coefficient is much less significant than that of temperature. In addition, the applicant performed an analysis to address the effects of measurement uncertainties of the PRHR heat transfer coefficient on the plant behavior. The analysis reduced the primary-side heat transfer coefficient, calculated using the Dittus-Boelter correlation, by 25 percent. The analysis shows that reducing the PRHR primary-side heat transfer coefficient by 25 percent results in a small reduction in the overall PRHR heat transfer rate, and that the reduction in heat transfer delays the time of the calculated peak RCS pressure values but does not significantly affect the magnitude of the calculated peak RCS pressure or peak pressurizer water volume. Because the applicant's analysis shows that the calculated PRHR tube flow and primary temperature fall within the PRHR test range, and the magnitude of the PRHR primary-side heat transfer coefficient during the low-flow conditions of the loss of ac power events does not significantly affect the calculated decay heat removal, peak pressure, and pressurizer water volume, the staff concludes that the PRHR heat transfer coefficient calculated at low-flow conditions is adequate and acceptable for use in the loss of ac power event analysis.

The applicant used the LOFTRAN, FACTRAN, and VIPRE-01 codes with the revised thermal design procedure (RTDP) described in WCAP-11397-P-A to perform DNBR calculations. In the analysis, initial reactor power, pressurizer pressure, and RCS temperature are assumed to be at their nominal values consistent with steady-state, full-power operation. The analysis includes uncertainties in initial conditions, as described in the RTDP, in determining the DNBR limit during the transient. The functionality of the SG safety valves and pressurizer safety valves is assumed for steam releases, and the CMTs are assumed to actuate when the PRHR HX cools down the RCS enough to initiate a low cold-leg temperature "S" signal.

In considering the effects of a LOOP, the applicant assumed that the power loss and the resulting coastdown of the RCPs occurs 3 seconds after the turbine trip. If the LOOP occurs at the start of the event, the calculated DNBR transient will be the same as predicted for the event involving a complete loss of RCS flow, which a LOOP initiates at the beginning of the event. Section 15.2.3.2 of this report discusses the results of the complete loss of RCS flow event.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that the worst single active failure is the failure to open one of the two valves in the PRHR discharge line. During the transient, the reactor trips on the low SG water-level signal. The loss of ac power is assumed following the reactor trip. Loss of ac power causes the RCPs to coast down. The PRHR HX actuates on a low narrow-range SG water level coincident with low startup feedwater flow rate, and the CMTs actuate when the PRHR HX cools the RCS enough to initiate a low cold-leg temperature "S" signal.

The results of the analysis show that the calculated minimum DNBR meets the safety DNBR limit, and the long-term PRHR heat removal capacity is sufficient to remove the decay heat. In addition, the results show that the peak RCS pressure does not exceed the RCS pressure limit, pressurizer overfilling does not occur, and the integrity of the RCS is maintained. Thus, the SRP acceptance criteria for the loss of ac power are met, and the staff concludes that the analysis is acceptable.

15.2.2.7 Loss of Normal Feedwater Flow (DCD Tier 2, Section 15.2.7)

An LONF flow event, a moderate-frequency event, may be caused by feedwater pump failures, valve malfunctions, or loss of ac power sources. Following an event involving an LONF, the SG water inventory decreases as a consequence of continuous steam supply to the turbine. The mismatch between the steam flow to the turbine and the feedwater leads to the reactor trip on a low SG-level signal. Either a low narrow-range SG water-level signal, coincident with a low startup feedwater flow rate signal, or a low wide-range SG water-level signal actuates the PRHR HX. The PRHR HX transfers the decay heat to the in-containment refueling water storage tank (IRWST) and provides a continuous core heat removal capability following a loss of normal and startup feedwater. The RCS cooldown by the PRHR leads to the actuation of a low cold-leg temperature "S" signal, which activates the CMTs. The CMTs inject the cold borated water into the RCS. Both the PRHR HX and CMTs provide heat removal capability for long-tem decay heat removal.

The applicant performed the analysis of this event with the NRC-approved LOFTRAN computer code. Initial reactor power is assumed to be 102 percent of the rated power. The relief of steam in the secondary system is assumed to be achieved through the SG safety valves. Upon initiation of the event, the RCPs are assumed to operate until they are automatically tripped by CMT actuation on a low cold-leg temperature "S" signal. In the analysis, only safety-related systems are assumed to function to mitigate the consequences of the events. A low wide-range SG water level actuates the PRHR HX.

In considering the effects of measurement uncertainties, the initial temperature and pressurizer pressure are assumed to be 4 °C and 0.446 MPa (7 °F and 50 psi) below the nominal values. In response to RAI 440.075, related to the staff's concern about the adequacy of the initial temperature and pressure assumed in the analysis, the applicant replied that during the LONF event, the availability of ac power is assumed after reactor trip, and the CVCS makeup pump is assumed to operate. A lower initial pressurizer pressure results in a slightly higher CVCS flow rate, which is calculated with the LOFTRAN code as a function of the RCS pressure and, in turn, results in a slightly higher peak pressurizer water level with a lower margin to pressurizer overfilling. A lower initial RCS temperature results in a higher initial RCS mass and, thus, a lower margin to the pressurizer overfilling. In addition, the applicant performed a sensitivity study and showed that the effects of the initial RCS temperature and pressurizer pressure on the plant transient behavior are insignificantly small. Therefore, the staff concludes that the initial RCS temperature and pressure assumed in the analysis are acceptable.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that the worst single active failure is a failure of one of the two valves in the PRHR discharge line to open.

In considering the effects of a LOOP, the applicant assumed that the power loss and the resulting coastdown of the RCPs occur 3 seconds after the turbine trip for DNBR calculations. The LOOP causes a coastdown of the RCPs. The applicant showed that the scenario of the loss of ac power event, for which the RCPs trip instantaneously, bounds the LONF transient event followed by the consequential LOOP after turbine trip. The analysis of the loss of ac power event, presented in DCD Tier 2, Section 15.2.6, shows that the calculated minimum DNBR exceeds the safety DNBR limits. Therefore, the minimum DNBR for the loss of feedwater event also exceeds the safety DNBR limits.

The applicant performed the analyses for the peak RCS pressure and LTC for the loss of feedwater event using approved methods. The results show that the peak RCS pressure does not exceed the RCS pressure limit, pressurizer overfilling does not occur, and the integrity of the RCS is maintained. For LTC, the analysis demonstrates that the PRHR can remove the core decay heat faster than it builds up during the transient, and the long-term PRHR heat removal capacity is sufficient to remove the decay heat. Thus, the SRP acceptance criteria for the LONF event are met. Therefore, the staff concludes that the analysis is acceptable.

15.2.2.8 <u>Feedwater System Pipe Break (DCD Tier 2, Section 15.2.8)</u>

An FLB is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to maintain shell-side water inventory in the SGs. The FLB may reduce the ability to remove heat generated by the core from the RCS, because fluid in the SG is discharged through the break, and the break may be large enough to prevent the addition of main feedwater after the trip. Signals of high pressurizer pressure, overtemperature delta T, low SG water level in either SG, low steamline pressure in either SG, and high-2 containment pressure may actuate a reactor trip. During the event, either a low narrow-range SG water level, coincident with a low startup feedwater rate signal, or a low wide-range SG water-level signal may actuate the PRHR HX. In the long term, the PRHR HX removes the decay heat and provides continuous core heat removal capability. A low cold-leg temperature "S" signal may actuate the CMTs.

The applicant assumed a break in a feedwater line between the check valve and the SG with a double-ended rupture of the largest feedwater line. The applicant assumed a double-ended break area of 0.163 m^2 (1.755 ft^2). This break size is identified as the limiting break case because it results in the highest water inventory in the pressurizer and the highest peak primary pressure. In a followup to RAI 440.076, the staff requested the applicant to discuss the analysis used to determine the limiting break case for the AP1000 design. In its response, the applicant provided the results of a break size spectrum study for FLB events. The sensitivity study compares the results of the limiting FLB case presented in the DCD with FLB analysis for break sizes of 100 percent, 50 percent, 25 percent, and 10 percent of the feedwater nozzle, assuming the break occurred at the initial transient time. The results confirmed that the DCD case is the limiting case resulting in the highest RCS water inventory in the pressurizer and the highest peak primary pressure.

The applicant performed the analysis of this event using the LOFTRAN computer code. The initial power is assumed at 102 percent of the rated power. Initiation of the reactor trip is assumed when the low narrow-range SG level setpoint is reached on the affected SG. In minimizing the heat removal capability of the SG with the ruptured feedwater line, a saturated liquid discharge is assumed for the break fluid until all the water is discharged from the SG with the ruptured feedwater line. In minimizing the margin to the pressurizer overfilling, the initial pressurizer water level is assumed at a maximum allowable value. The applicant has considered the cases with a LOOP occurring simultaneously with the pipe break, with the LOOP occurring during the FLB accident, and without a LOOP, and identified (in the response to RAI 440.077) that the FLB with the LOOP occurring at the time of the break is the limiting case, resulting in the highest RCS pressure. In the analysis for the limiting FLB case, the low wide-range SG water level is assumed to actuate the PRHR HX, with a maximum delay time of 15 seconds to initiate automatic alignment of the PRHR HX valves. In addition, the applicant took no credit for the high pressurizer trip, for charging or letdown, or for energy deposited in RCS metal during the RCS heatup. During an FLB event, the ESFs required to function include the PRHR, CMTs, and steam isolation valves.

The applicant considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that the worst single active failure is the failure of one of the two valves in the PRHR discharge line to open. In considering the effects of a LOOP on the DNBR calculations, the applicant assumed that the power loss and the resulting coastdown of the RCPs occur 3 seconds after the turbine trip.

The staff notes that the non-safety-related pressurizer spray is credited for heat removal to limit the increase in the peak RCS pressure. In addition, the analysis assumes a low pressurizer safety-valve setpoint. Both assumptions will result in a lower peak RCS pressure and, thus, are not conservative. The AP600 FLB analysis made the same nonconservative assumptions. During the previous AP600 review, the staff asked the applicant to reanalyze the FLB event and quantify the effects of the pressurizer spray and a low pressurizer safety-valve setpoint on the results of the FLB event. In Westinghouse letter DCP/NRC 0962, dated July 18, 1997, the applicant replied that it had reanalyzed the event without pressurizer spray operable and with the pressurizer safety-valve setpoint at its normal value. The confirmatory analysis showed a peak RCS pressure of 18.08 MPa (2624 psia) and an increase of 27.6 kPa (4 psi) as compared to the DCD case, and it confirmed that the effects of the nonconservative assumptions on the calculated peak RCS pressure are small. Because the applicant's FLB analysis documented in the DCD shows that the RCS pressure response during an FLB event for the AP1000 design is similar to that of the AP600 design, the effects of the nonconservatism in modeling the pressurizer spray and pressurizer safety valves for the AP1000 FLB analysis will also be small. In addition, the AP1000 FLB analysis shows that the calculated peak RCS pressure is less than 17.93 MPa (2600 psia). Therefore, the staff concludes that the calculated peak pressure demonstrates that the margin (greater than 1.03 MPa (150 psi)) to the safety limit of

110 percent of the design pressure is sufficient to compensate for the nonconservative assumptions of the pressurizer spray and pressurizer safety-valve models discussed above.

The applicant performed the FLB analysis using the LOFTRAN computer code. The results of the analysis show that the peak pressures of the RCS and SG are below 110 percent of the design pressures, and the pressurizer does not overfill during the transient. For LTC, the analysis demonstrates the core coolability by showing that the PRHR removes the core decay heat faster than it builds up. For DNBR calculations, a LOOP is assumed to occur 3 seconds after turbine trip and cause a coastdown of the RCPs. The applicant showed that, for the transient up to the reactor trip and complete insertion of control rods (where the minimum DNBR occurs), the scenario of the loss of ac power event, for which the RCPs trip instantaneously, bounds the FLB event followed by the consequential LOOP after turbine trip. The analysis of the loss of ac power event, presented in DCD Tier 2, Section 15.2.6, shows that the calculated minimum DNBR exceeds the safety DNBR limits. Therefore, the minimum DNBR for the FLB event also exceeds the safety DNBR limits.

Because the applicant used NRC-approved methods, the assumptions used in the analysis are adequate in maximizing RCS pressure and minimizing the calculated DNBRs, and the results of the analysis meet the acceptance criteria of SRP Section 15.2.8 for the FLB break with respect to the pressure and safety DNBR limits, the staff concludes that the analysis is acceptable.

15.2.3 Decrease in Reactor Coolant System Flow Rate (DCD Tier 2, Section 15.3)

The applicant has analyzed the transients specified in SRP Section 15.3 for cases resulting from a decrease in RCS flow rate. The transients include (1) partial loss of forced reactor coolant flow, (2) complete loss of forced reactor coolant flow, (3) RCP shaft seizure (locked rotor), and (4) RCP shaft break. The applicant has also identified the limiting case with regard to the ability of the RCS boundary and fuel rod cladding to withstand the consequences of transients. The staff has reviewed the applicant's analysis, as discussed in Sections 15.2.3.1 through 15.2.3.4 of this report.

15.2.3.1 Partial Loss of Forced Reactor Coolant Flow (DCD Tier 2, Section 15.3.1)

A mechanical or electrical failure in an RCP, or a fault in the power supply to the pumps supplied by an RCP bus, may cause partial loss of RCS flow, a moderate-frequency event. The low primary coolant flow reactor trip signal in any reactor coolant loop provides protection against this event.

The applicant analyzed the partial loss of flow event using the following NRC-approved computer codes. LOFTRAN calculates the nuclear power transient, the primary system pressure and temperature transients, and the core flow during the transient based on the RCS loop coastdown flow from COAST. FACTRAN calculates the heat flux transient based on the nuclear power and flow from LOFTRAN. VIPRE-01 calculates the DNBRs during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR calculations are based on the RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, pressure, and RCS temperature are assumed to be at their nominal values, and the uncertainties in initial conditions are included in the DNBR limit as described in the RTDP.

In maximizing the core power and, thus, minimizing the DNBRs, the applicant used the least negative MTC and a large absolute value of the Doppler power coefficient. The applicant calculated the RCP flow coastdown based on RCS pressure losses and RCP characteristics. Reactor coolant fluid momentum is neglected to obtain a low coastdown flow, which will result in lower calculated DNBRs.

In considering the effects of a LOOP, the applicant assumed that the power loss and resulting coastdown of the RCPs occur 3 seconds after the turbine trip. In addition, turbine trip occurs 5 seconds following a reactor trip condition. This delay to turbine trip is a feature of the AP1000 reactor trip system (RTS). The LOOP primarily causes the remaining operating RCPs to coast down. The analysis shows that the LOOP will have no effect on the calculated minimum DNBR, because a rapid decrease in the heat flux following a reactor trip significantly compensates for the decrease in the RCS flow caused by a LOOP following a turbine trip, and the minimum DNBR occurs before initiation of a LOOP. The staff finds that the applicant's assumptions are conservative and thus acceptable.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these systems or equipment adversely affects the consequences of the events.

Because an event involving the loss of three of the four RCPs is not credible, the applicant did not analyze the consequences of this event. In addition, the core flow would be much lower for an event involving the loss of two RCPs than for an event involving a loss of one RCP. Therefore, the results for an event with a loss of two RCPs are limiting and bound the event where only one RCP is lost. In DCD Tier 2, Sections 15.3.1 and 15.3.2 analyze and discuss the loss of two RCPs and the loss of four RCPs, respectively.

The applicant analyzed the event using NRC-approved methods, and the results of the analysis for the limiting case, the loss of two RCPs, show that, with and without offsite power available, the RCS pressure will remain within 110 percent of the design pressure, and the minimum DNBR will remain above the safety DNBR limit. The staff finds that the results of the analysis meet the acceptance criteria of SRP Section 15.3.1 regarding the limits for the calculated RCS pressure and the minimum DNBR. Therefore, the staff concludes that the analysis is acceptable.

15.2.3.2 Complete Loss of Forced Reactor Coolant Flow (DCD Tier 2, Section 15.3.2)

A simultaneous loss of electrical power to all RCPs may cause a complete loss of forced flow from the RCPs. A LOOP and the resulting loss of all forced reactor coolant flow through the reactor core cause an increase in the average coolant temperature and a decrease in the margin to DNB. The signals of low RCP speed or the low reactor coolant loop flow will trip the reactor.

For the case analyzed with a complete loss of flow, the method of analysis and the assumptions made for initial conditions and reactivity coefficients are identical to those for a partial loss of flow, except that the RCP underspeed trip actuates a reactor trip following the loss of power supply to all pumps at power. Section 15.2.3.1 of this report discusses the methods and assumptions used in the analysis. The results of the applicant's analysis show that the peak RCS pressure during the transient will remain below 110 percent of the system design pressure, and the calculated DNBR will remain above the design DNBR safety limit. Thus, the integrity of the RCS pressure boundary is not endangered, no fuel failure is predicted to occur, and core geometry and control rod insertability will be maintained with no loss of core cooling capability. Therefore, the staff determines that the analysis meets the acceptance criteria of SRP Section 15.3.2 with respect to the integrity of the RCS pressure boundary and the fuel rods, and it concludes that the analysis is acceptable.

15.2.3.3 RCP Shaft Seizure (Locked Rotor) (DCD Tier 2, Section 15.3.3) and RCP Shaft Break DCD Tier 2, Section 15.3.4)

An instantaneous seizure of an RCP rotor may cause RCP shaft seizure, and an instantaneous failure of an RCP shaft may cause an RCP shaft break. Both events are classified as limiting-fault events.

For both cases, the RCS flow through the affected reactor loop drops rapidly, leading to a reactor trip on a low-flow signal. After the reactor trip, energy stored in the fuel rods continues to be transferred to the coolant, causing the coolant temperature to increase and the coolant to expand. During this period, heat transfer to the shell side of the SGs drops, because the reduced flow results in a decreased SG tube convective heat transfer coefficient, and the reactor coolant in the tube side cools down while the shell-side temperature increases because of steam flow through the turbine reducing to zero upon plant trip. The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the SGs, causes pressure to increase throughout the RCS. The pressurizer safety valves will open to release steam from the pressurizer. The rapid decrease in the RCS flow also results in a decrease in the DNBR.

The analysis discussed in DCD Tier 2, Sections 15.3.3 and 15.3.4, indicates that the RCP shaft seizure event with a LOOP bounds the RCP shaft break event with a LOOP, because the slightly faster RCP flow coastdown for the shaft seizure event results in a lower minimum DNBR.

The applicant analyzed the more limiting RCP shaft seizure for cases with and without offsite power available. For cases without power available, a LOOP is assumed to occur at 3 seconds following turbine trip. A LOOP causes a simultaneous loss of feedwater flow, condenser inoperability, and coastdown of all RCPs. The analysis takes no credit for restoration of offsite power before initiation of shutdown cooling.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these systems or equipment adversely affects the consequences of the events. The applicant analyzed this event using the LOFTRAN code for the system response and the FACTRAN code for the heat flux calculation at the hot spot. The NRC has approved both codes for these analyses. The low reactor coolant flow signal actuates the reactor trip. The analysis takes no credit for the pressure-reducing effects of pressurizer spray, steam dump, or controlled feedwater flow.

The results of the analysis show that the maximum RCS pressure remains less than 110 percent of the design pressure. The applicant also indicated, in the response to RAI 440.080, that the calculated minimum DNBR is above the safety-limit DNBR and thus assures no rod failure. However, for the purpose of calculating dose releases, the applicant conservatively assumed that 16 percent of rods are damaged. The results show that the dose release limits are met even with the assumed 16 percent of fuel rods damaged. Section 15.3 of this report discusses the staff's evaluation of the radiological calculations.

The applicant used NRC-approved methods with results that show that the peak RCS pressure will remain within 110 percent of the design pressure, and the radiological release will remain within the 10 CFR 50.34(a)(1)(ii)(D)(*1*) limits. Therefore, the staff finds that the analysis for the RCP shaft seizure event meets the acceptance criteria of SRP Section 15.3.3 and is acceptable.

15.2.4 Reactivity and Power Distribution Anomalies (DCD Tier 2, Section 15.4)

In DCD Tier 2, Section 15.4, the applicant presented the analytical results of events caused by reactivity and power distribution anomalies. The transients include (1) uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition, (2) uncontrolled RCCA bank withdrawal at power, (3) RCCA misalignment, (4) startup of an inactive RCP at an incorrect temperature, (5) malfunction or failure of the flow controller in a boiling water recirculation loop that results in an increased reactor coolant flow rate, (6) CVCS malfunction that results in a decrease in the boron concentration in the reactor coolant, (7) inadvertent loading and operation of a fuel assembly in an improper position, and (8) spectrum of RCCA ejection accident. The applicant has also identified the limiting case with regard to ability of the RCS boundary and fuel rod cladding to withstand the consequences of transients. The following sections discuss the staff's evaluation of the analytical results.

15.2.4.1 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low-Power Startup Condition (DCD Tier 2, Section 15.4.1)

A malfunction of the reactor control or rod control systems may cause an uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition. The source-range high neutron flux reactor trip, intermediate-range high neutron flux reactor trip, power-range high neutron flux reactor trips (low and high setting), and high-neutron flux rate reactor trip provide protection against this event.

For the analysis of this transient, the applicant used TWINKLE for the average power generation calculation, FACTRAN for the hot rod heat transfer calculation, and VIPRE-01 for the DNBR calculation. The analysis assumes a conservatively low value of Doppler-power coefficient and the least negative moderator coefficient to maximize the peak heat flux. Reactor trip is assumed to occur on the low setting of the power-range neutron flux channel at 35 percent of full power. A 10-percent uncertainty is added to the reactor trip setpoint value. The analysis assumes the maximum positive reactivity addition rate that exceeds that for the simultaneous withdrawal of the combination of two sequential RCCA banks having the greatest combined worth at maximum speed of 1.14 m/min (45 in./min). The DNBR calculation assumes the most limiting axial and radial power shapes associated with the two highest-worth banks in their high-worth position. The initial power level is assumed to be below the power level expected for any shutdown condition (10^{-9} of nominal power). The combination of the highest reactivity addition rate and lowest initial power produces the highest peak heat flux, resulting in a lowest calculated minimum DNBR, and is a conservative assumption.

The applicant considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these system or equipment adversely affects the consequences of the event. Since the turbine is initially in the tripped condition for the plant at a subcritical or low-power startup condition, a consequential LOOP following the turbine trip is not a credible event and, thus, is not modeled in the analysis.

The results of the analysis for this event show that the maximum heat flux is much less than the full-power value, and average fuel temperature increases to a value lower than the nominal full-power value. The calculated minimum DNBR is above the safety DNBR limits.

The staff has reviewed the assumptions related to the reactivity worth and reactivity coefficients used in the analysis and found that they maximize the heat flux, thereby minimizing the calculated DNBRs, and are conservative. The staff has reviewed the calculated consequences of this transient and found that they meet the requirements of GDC 10, in that the specified acceptable fuel design limits are not exceeded. The applicant also meets the requirements of GDC 20, "Protection System Functions," in that the reactivity control system can be initiated automatically so that specified acceptable fuel design limits are not exceeded. In addition, the applicant meets GDC 25, "Protection System Requirements for Reactivity Control Malfunctions," in that a single malfunction in the reactivity control systems will not cause the specified acceptable fuel limits to be exceeded. Therefore, the staff concludes that the analysis satisfies the acceptance criteria of SRP Section 15.4.1 and is acceptable.

15.2.4.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (DCD Tier 2, Section 15.4.2)

A malfunction of the reactor control or rod control systems may cause an uncontrolled withdrawal of an RCCA bank in the power operating range, a moderate-frequency event. Such an event causes an increase in fuel and coolant temperature as a result of the core-turbine power mismatch. Reactor trips, including the high neutron flux trip, overpower and overtemperature delta T trips, and pressurizer high-pressure and pressurizer water-level trips, provide plant protection.

The applicant performed the analyses using NRC-approved methods. The LOFTRAN code calculates the nuclear power transient, the flow coastdown, the primary system pressure transient, and the primary coolant temperature transient. The FACTRAN code calculates the heat flux based on the nuclear power and flow from LOFTRAN. The VIPRE-01 code calculates the DNBR using the heat flux from FACTRAN and the flow, inlet core temperature, and pressure from LOFTRAN. The DNBR calculations are based on the RTDP described in WCAP-11397-P-A. In the DNBR calculations, the initial reactor power, pressure, and RCS temperature are assumed to be at their nominal values, and the uncertainties in initial conditions are included in the DNBR limit as described in the RTDP. The maximum positive reactivity insertion rate is assumed to exceed that for the simultaneous withdrawal of the combination of the two control banks having the maximum combined worth at maximum speed. The high neutron flux signal is assumed to occur at 118 percent of nominal full power. The overtemperature and overpower delta-T trips include instrumentation and setpoint uncertainties, and the delays for trip actuation are assumed to be at the maximum values. The applicant analyzed cases with both minimum and maximum reactivity coefficients and performed a sensitivity study of the effects of initial power levels (10-, 60-, and 100-percent power) and reactivity insertion rates (from 1 pcm/s to 110 pcm/s) on the consequences of the event.

The applicant considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these systems or equipment adversely affects the consequences of the event. In addressing the LOOP issue, the applicant assumed that the power loss and the resulting coastdown of the RCP flow occur 3 seconds after the turbine trip.

The results of the analysis show that the DNBR does not fall below the safety limit for all cases. Therefore, fuel integrity and adequate fuel cooling are maintained. The calculated peak RCS pressure will remain less than 110 percent of the design pressure. The staff finds that the analysis meets the acceptance criteria of SRP Section 15.4.2 with respect to the integrity of the fuel and pressure boundaries and, therefore, concludes that the analysis is acceptable.

15.2.4.3 Rod Cluster Control Assembly Misalignment (DCD Tier 2, Section 15.4.3)

RCCA misalignment incidents include one or more dropped RCCAs within the same group, a misaligned full-length assembly, and withdrawal of a single RCCA during operation at power. Asymmetric power distributions sensed by in-core or ex-core neutron detectors or core exit thermocouples, rod deviation alarms, or rod position indicators can detect misaligned rods. The deviation alarm alerts the operator to rod deviation from the group position in excess of 5 percent of span.

The applicant considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the events, and it determined that no single active failure in these systems or equipment adversely affects the consequences of the events. In considering the effects of a LOOP, the applicant assumed that a power loss and the resulting coastdown of the RCPs occur 3 seconds after the turbine trip.

The following sections discuss the staff's evaluation of the analysis for a dropped full-length assembly, a misaligned full-length assembly, and withdrawal of a single RCCA during operation at power.

15.2.4.3.1 Analysis for a Dropped Full-Length Assembly

For an event with one or more RCCAs dropped from the same group, the core power decreases and the core radial peaking factor increases. The reduced core power and continued steam supply to the turbine cause the reactor coolant temperature to decrease. In the manual control mode, the positive reactivity feedback causes the reactor power to rise to the initial power level at a reduced inlet temperature with no power overshoot. In the automatic control mode, the plant control system (PLS) detects the reduction in core power and initiates control bank withdrawal in order to restore the core power. As a result, power overshoot occurs, resulting in a lower calculated DNBR. The applicant determined that the automatic operating mode bounds the manual operating mode and is the limiting DNBR case.

The applicant analyzed the rod drop events in the automatic control mode using the nuclear models with the computer codes described in DCD Tier 2, Table 4.1-2, for the calculation of the hot channel factor, the LOFTRAN code for the system response, and the VIPRE-01 code for the DNBR calculation. The results show that the calculated minimum DNBR exceeds the safety limit DNBR for any single or multiple RCCA drop from the same group, and the peak RCS pressure will remain less than 110 percent of the design pressure. The staff finds that the analysis satisfies the acceptance criteria of SRP Section 15.4.3 with respect to the minimum DNBR and peak pressure and, therefore, concludes that the analysis for the RCCA drop event is acceptable.

15.2.4.3.2 Analysis for a Misaligned Full-Length Assembly

For RCCA misalignment situations, the applicant analyzed the two most limiting DNBR cases, including (1) RCCA misalignments in which one RCCA is fully inserted with the rest of the RCCAs at or above their insertion limits, and (2) a case in which a group is inserted to its insertion limit, and a single RCCA in the group is stuck in the fully withdrawn position with the reactor at full-power conditions. In the DNBR analysis, the initial reactor power, pressurizer pressure, and RCS temperature are assumed to be at their nominal values consistent with steady-state full-power operation. The radial peaking factor associated with the misaligned RCCA for these two limiting cases is calculated using the approved methods described in DCD Tier 2, Table 4.1-2. Uncertainties in initial conditions, as described in WCAP-11397-P-A, are included in determining the DNBR limit during the transient. The analysis shows that the minimum DNBR exceeds the safety DNBR limit. Therefore, the staff concludes that the analysis is acceptable because it meets the acceptance criteria of SRP Section 15.4.3 with respect to the fuel cladding integrity.

15.2.4.3.3 Analysis for Withdrawal of a Single RCCA

The inadvertent withdrawal of a single assembly requires multiple failures in the rod control system, multiple operator errors, or deliberate operator actions combined with a single failure of the rod control system. Because of the low likelihood of the event, the applicant classified the single assembly withdrawal as an infrequent event for the AP1000 design. The event categorization is consistent with that approved by the staff for Westinghouse operating plants and, therefore, is acceptable. The transient resulting from such an event is similar to that resulting from a bank withdrawal, but the increased peaking factor causes DNB to occur in the region surrounding the withdrawn assembly. The radial peaking factor associated with the single RCCA withdrawal is calculated using the approved methods described in DCD Tier 2, Table 4.1-2. Uncertainties in initial conditions, as described in WCAP-11397-P-A, are included in determining the DNBR limit during the transient. In response to RAI 440.081, the applicant indicated that less than 4 percent of the rods in the core experience DNB during the limiting case, an event where RCCA rod banks are at the full-power rod insertion limits, except for one RCCA which is fully withdrawn. For the purpose of calculating dose releases, the applicant conservatively assumed that 5 percent of the fuel rods failed. The assumption of fuel failure for the dose release calculation is more conservative than the guidance in SRP Section 4.4, which states that all rods that experience DNB (in this case, less than 4 percent of the fuel rods) should be assumed to fail. Therefore, the staff concludes that the assumption is acceptable.

For the single rod withdrawal event (an infrequent event), the applicant meets the requirements of GDC 27, "Combined Reactivity Control Systems Capability," by demonstrating that the resultant fuel damage is limited, such that control rod insertability is maintained, and no loss of core coolability results. The DNBR calculation shows that a small fraction (4 percent) of the fuel rods may experience cladding perforation. The dose release calculation results show that the release acceptance criteria are met. Therefore, the staff concludes that the analysis is acceptable. Section 15.3 of this report discusses the staff's evaluation of the radiological consequence calculations.

15.2.4.4 Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature (DCD Tier 2, Section 15.4.4)

Starting an idle RCP increases the injection of cold water into the core, which causes a reactivity insertion and subsequent power increase.

Because the TSs (described in DCD Tier 2, Chapter 16, TS 3.4.4) do not allow operation with an RCP inoperable for Modes 1 and 2, the applicant did not analyze this event at Modes 1 and 2.

15.2.4.5 A Malfunction or Failure of the Flow Controller in a Boiling-Water Reactor Loop that Results in an Increased Reactor Coolant Flow (DCD Tier 2, Section 15.4.5)

This section does not apply to the AP1000 design.

15.2.4.6 Chemical and Volume Control System Malfunction that Results in the Boron Dilution in the Reactor Coolant (DCD Tier 2, Section 15.4.6)

Failures of the demineralized water transfer and storage system (DWS) or CVCS because of control system or operator error or mechanical failure cause an inadvertent boron dilution. The CVCS and DWS are designed to limit the dilution rate to values that allow sufficient time for automatic or operator actions to terminate the dilution before the shutdown margin is lost. The boric acid and blended flow rates, the status of the CVCS makeup pumps, and the boron dilution rate deviation alarm indicate the dilution rate. In Modes 1 and 2, either a rod insertion limit—low-level alarm or an axial flux difference alarm will alert the operator to an unplanned boron dilution event. Furthermore, when the reactor is subcritical, the available alarms and indications to alert the operator to a boron dilution event include (1) a high flux at shutdown alarm, (2) indicated source-range neutron flux count rates, (3) an audible source-range neutron flux rate, and (4) a source-range neutron flux multiplication alarm. Upon any reactor trip signal, source-range flux multiplication signal, low battery charger input voltage signal, or a safety injection signal, a safety-related function automatically isolates the potential unborated water from the DWS and thereby terminates the dilution.

The applicant analyzed the boron dilution event for all modes of operation. The applicant performed the analysis using the method consistent with that employed in boron dilution event analysis for Westinghouse operating plants. The method consists of a generic fluid mixing model. The nodal scheme in the model includes a node to represent the RCS volume and a flowpath to represent CVCS fluid transportation.

All cases discussed below assume a dilution flow rate of 12.6 liters per second (L/sec) (200 gallons per minute (gpm)) of unborated water, which is the maximum makeup flow with both makeup pumps operating (as stated in DCD Tier 2, Section 9.3.6.6.1.2).

15.2.4.6.1 Boron Dilution during Refueling (Mode 6)

Uncontrolled boron dilution is not a credible event during the refueling mode because administrative controls isolate the RCS from the potential source of unborated water by locking closed specified valves in the CVCS system during this mode of operation. The boric acid tank (BAT), which contains borated water, supplies makeup water during refueling.

15.2.4.6.2 Boron Dilution during Modes 3, 4, and 5 of Operation

In Modes 3, 4, and 5, the analysis assumed a shutdown margin of 1.6 percent delta K/K (the minimum value required by the AP1000 TSs for the shutdown modes) and the minimum initial reactor coolant volumes. Following the AP1000 TS LCO 3.4.8 requirements, the applicant assumed the operation of one RCP. In maximizing the effect of the boron dilution, the applicant used the minimum amount of the water in the RCS to mix with the incoming unborated water. For Mode 3, the minimum RCS water volume assumed is the total RCS volume without the pressurizer and surgeline and the RV upper head volume. For Mode 4, the water volume assumed in the analysis is the water volume of the RV without the RV upper head volume when the normal residual heat removal system (RNS) is used to remove the decay heat. For Mode 5, the water volume used in the analysis is the RCS water volume corresponding to the water level at midloop operations. The source-range flux multiplication signal is assumed to actuate an alarm in the control room and close the DWS isolation valves when the neutron flux increases by 60 percent over any 50-minute period (per Item 15.a of AP1000 TS Table 3.3.2-1). The analysis shows that the automatic closure of the DWS isolation valves initiated by the source-range flux multiplication signal occurs about 56.3 minutes after the start of the dilution for Mode 3, 12.3 minutes for Mode 4, and 12.03 minutes for Mode 5. The results of the analysis show that the automatic isolation of the DWS valves terminates the boron dilution and maintains the plant in a subcritical condition. The staff determined that the analysis meets the guidance in SRP Section 15.4.6 with respect to core criticality and concludes that it is acceptable.

15.2.4.6.3 Boron Dilution during Startup (Mode 2)

The plant is in the startup mode only for startup testing at the beginning of each cycle. During this mode of operation, rod control is manual. The applicant performed an analysis of an inadvertent deboration event at initial conditions representative of the startup mode of operation with an assumed unborated water flow rate of 12.6 L/sec (200 gpm). Following the requirements of TSs 3.1.1 and 3.4.4, the applicant assumed an available shutdown margin of

1.6 percent delta K/K and operation of four RCPs. The initial RCS water assumed in the analysis is the water volume included in all the RCS volumes except the pressurizer and surgeline. Calculation of the SG tube volume accounts for 10-percent tube plugging. The results of the analysis show that a reactor trip from a signal on the intermediate-range neutron flux will (1) initiate closure of the DWS isolation valves (DCD Tier 2, Table 15.4-1), (2) terminate the boron dilution, and (3) maintain the plant in a subcritical condition. Therefore, the staff determined that the analysis meets the guidance in SRP Section 15.4.6 with respect to core subcriticality and concludes that the analysis is acceptable.

15.2.4.6.4 Boron Dilution during Power Operation (Mode 1)

For Mode 1, the applicant analyzed both the manual mode and the automatic mode cases. Both cases use the same initial RCS water volume as for Mode 2 discussed above. For the manual mode case, the analytical results show that a reactor trip on the overtemperature delta T will initiate closure of the DWS isolation valves and terminate the boron dilution without the occurrence of a posttrip return to criticality. Because a reactor trip isolates DWS valves and terminates the event, the subsequent LOOP assumption following a turbine trip (which occurs immediately after a reactor trip), as required by GDC 17, will not affect the results of the deboration event for the case in manual mode.

For the automatic mode case, the slow insertion of the control rods to avoid the reactor trip compensates for an increase in the power and temperature caused by a boron dilution event. Because a reactor and turbine trip does not occur as predicted in the analysis for the case in automatic mode, the consequential LOOP following a turbine trip (as required by GDC 17) is not a credible event and thus is not modeled in the analysis. For the AP1000 design, the redundant pretrip alarms available to the operator for Mode 1 operation include a low-level rod insertion limit alarm and an axial flux difference alarm. The analysis shows an available time interval from a low-low rod insertion limit alarm, attributable to boron dilution, to loss of shutdown margin of about 328 minutes (DCD Tier 2, Table 15.4-1). The staff finds that the applicant has demonstrated compliance with the guidance in SRP Section 15.4.6, in that the redundant pretrip alarms should alert the operator to the initiation of the event in sufficient time (at least 15 minutes) to ensure detection of the boron dilution event during Mode 1 before possible loss of shutdown margin.

The analysis shows that (1) for Mode 6, the design and procedures prevent the inadvertent boron dilution events, (2) for Mode 1 in a manual control mode and Modes 2 through 5, the automatic closure of the DWS isolation valves minimizes the approach to criticality and maintains the core in a subcritical condition, thus ensuring the integrity of the fuel and RCS pressure boundary, and (3) for Mode 1 in an automatic control mode, a number of alarms and indications can alert an operator to a boron dilution event, and the operator has sufficient time (328 min) to detect and terminate the event before loss of shutdown margin. Therefore, the staff determines that the analysis has satisfied the guidance in SRP Section 15.4.6 with respect to the operator action times and core subcriticality and, therefore, concludes that it is acceptable.

In support of the boron mixing model used in the analysis, the applicant specified a required minimum core flow rate. Specifically, TS LCO 3.4.8 requires that at least one RCP operate with a total flow through the core of at least 630 L/sec (10,000 gpm) while in Modes 3, 4, and 5, whenever the reactor trip breakers are open. The staff requested, in RAI 440.106, that the applicant provide the basis to support the conclusion that the required core flow rate is sufficient to provide the well-mixed flow condition assumed in the boron dilution analysis. The applicant replied that the process of selecting 630 L/sec (10,000 gpm) included general consideration of the results reported in NUREG/CR-2733, "Experimental Data Report for LOFT Boron Dilution Experiment L6-6," issued June 1982. As discussed in EGG-LOFT-5867, "Quick-Look Report on LOFT Boron Dilution Experiment L6-6," issued May 1982, the key parameters of the loss-of-fluid test (LOFT) L6 series of tests were scaled based on the characteristics of the Westinghouse four-loop Trojan PWR. With its four cold-legs, the general configuration of the AP1000 inlet plenum region is similar to that of a four-loop plant.

The LOFT considered two low-pressure injection system flow rates that were scaled to provide equivalence to 189 L/sec (3000 gpm) and 378 L/sec (6000 gpm) residual heat removal (RHR) flow rates in the Trojan plant. Typical RHR-related TSs, intended to ensure adequate boron mixing in current Westinghouse-designed plants, allow operation in the applicable mode with a single operating RHR pump. EGG-M-03783, DE83 013666, "PWR Response to an Inadvertent Boron Dilution Event," presented at the Third Multiphase Flow and Heat-Transfer Symposium Workshop, April 18–20, 1983, documents the results of the tests. The report indicates that, for the 189 L/sec (3000 gpm) RHR flow equivalent case, "the fluid volume in the reactor vessel was well mixed and that the assumption of perfect mixing, though not strictly correct, is adequate for calculational purpose." For the 378 L/sec (6000 gpm) flow equivalent case, the reported test results show an even closer approach to perfect mixing. These results of the LOFTs have been used to support the typical plant TSs that generally accept an RHR flow in the vicinity of 189 L/sec (3000 gpm) as sufficient to justify the perfect mixing assumption modeled in the boron dilution analysis.

For the AP1000, the minimum core flow required by the TS exceeds the flow rates considered in the LOFT and currently accepted as providing adequate mixing in the operating plants. In addition, SR 3.4.8.1 places an operating speed requirement on a single RCP. Specifically, the SR requires that, in order to be considered as an operating RCP, the single pump involved must operate at a minimum of 25-percent rated speed, which produces a flow rate of 1,239 L/sec (19,688 gpm). This SR indicates that the total RCP flow is almost twice the required 630 L/sec (10,000 gpm) core flow and much greater than the 189 L/sec (3,000 gpm) value that is typically applied to operating plants. Since the general configuration of the AP1000 inlet flow plenum region is similar to that of a four-loop Westinghouse plant, the LOFTs that were scaled to a Westinghouse plant and are used to support the boron mixing model for the current Westinghouse plants apply to the AP1000 for selection of the minimum core flow rate to assure a well-mixed flow condition. In addition, the required minimum RCP flow through the core of 630 L/sec (10,000 gpm) is much greater than the value of 189 L/sec (3,000 gpm) that is typically applied to the operating plants and supported by the LOFT results. Therefore, the staff concludes that the required minimum core flow gives reasonable assurance that it is sufficient to provide the well-mixed flow conditions considered in boron dilution events that were analyzed to address the guidance in SRP Section 15.4.6, and is therefore acceptable.

15.2.4.7 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (DCD Tier 2, Section 15.4.7)

The applicant indicated that, during fuel loadings, it will follow strict administrative controls to prevent operation with a misplaced fuel assembly or a misloaded burnable poison assembly. Nevertheless, the applicant performed an analysis of the consequences of a loading error.

The applicant used the NRC-approved methods documented in WCAP-10965-P-A, "ANC: Westinghouse Advanced Nodal Computer Code," issued September 1986, to perform the analysis for this event. In DCD Tier 2, Figures 15.4.7-1 through 15.4.7-4, the applicant provided comparisons of power distributions calculated for the nominal fuel loading pattern and those calculated for four loadings with misplaced fuel assemblies or burnable poison assemblies. The selected non-normal loadings represent the spectrum of potential inadvertent fuel misplacement, including (1) a case in which a Region 1 assembly is interchanged with a Region 3 assembly, (2) a case in which a Region 1 assembly is interchanged with a neighboring Region 2 fuel assembly, (3) the enrichment error with a case in which a Region 2 fuel assembly is loaded in the core central position, and (4) a case in which a Region 2 fuel assembly, instead of a Region 1 fuel assembly, is loaded near the core periphery.

The analysis described above shows that resulting power distribution effects will either be detected by the startup test involving the in-core detector system (and hence be remediable) or cause an acceptable small perturbation within the measurement uncertainty of 5 percent. The testing requirements and the results of the analysis demonstrate that the applicant has met the requirements of GDC 13, "Instrumentation and Control," with respect to minimizing the possibility that a misloaded fuel assembly goes undetected (and minimizes the consequences of reactor operation in the event of inadvertent fuel misload). For the undetectable errors, the resulting power distribution changes fall within the acceptable measurement uncertainty, ensuring no fuel failure and satisfying the SRP Section 15.4.7 guidance. Therefore, the staff concludes that the analysis is acceptable.

15.2.4.8 Spectrum of Rod Cluster Control Assembly Ejection Accidents (DCD Tier 2, Section 15.4.8)

The mechanical failure of a control rod mechanism pressure housing may result in the ejection of an RCCA. For assemblies initially inserted, the consequences include a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. Although mechanical provisions have been made to render this accident extremely unlikely, the applicant has provided its analysis of the consequences of such an event. The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these systems or equipment adversely affect the consequences of the events. The staff has reviewed this analysis in accordance with SRP Section 15.4.8.

WCAP-7588, Revision 1-A, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods," issued January 1975, which the staff has previously reviewed and accepted, documents the methods used in the analysis.

The applicant analyzed two sets of cases for the rod ejection event, one initiated at hot full-power (HFP) and one initiated at hot zero-power (HZP). The analysis of both of these cases uses both beginning-of-cycle (BOC) and end-of-cycle (EOC) kinetics. DCD Tier 2, Table 15.4-3, lists the values of the initial plant parameters (power level, ejected rod worth, delayed neutron fraction, and trip reactivity) assumed in the analysis. The analysis credits the high neutron flux trip (high and low setting) to trip the reactor. The results show that the calculated values of hot spot radially averaged fuel enthalpy for the four analyzed cases are 181 calories per gram (cal/g) for HFP-BOC, 104 cal/g for HZP-BOC, 170 cal/g for HFP-EOC, and 117 cal/g for HZP EOC. These values of peak fuel enthalpy fall below the safety limit of 280 cal/g specified in SRP Section 15.4.8, "Spectrum of Rod Ejection Accidents." The calculated values also fall within the Westinghouse-specified analysis limit of 200 cal/g. In addition, the calculated pressure surge resulting from the rod ejection does not exceed the RCS emergency limits (Service Level C) and thus satisfies the guidance of SRP Section 15.4.8 with respect to the RCS pressure limit.

In considering the effects of a LOOP, the applicant assumed that the power loss and the resulting RCP coastdown occur 3 seconds after the turbine trip. The applicant has shown that the effect of a LOOP on the calculated minimum DNBR is negligible, because a rapid decrease in the heat flux after the control rod insertion compensates for the decrease in the RCS flow caused by a LOOP, and the minimum DNBR occurs before initiation of a LOOP.

The analysis shows that less than 10 percent of the fuel rods experience DNB as a result of the rod ejection event. For the purpose of calculating dose releases, the applicant conservatively assume that 10 percent of the fuel fails. The assumption of fuel failure for the dose calculation results in a higher radiological release dose and is conservative. Therefore, the assumption is acceptable.

Experimental data show failure of high burnup fuels at lower enthalpy values than the fuel enthalpy safety limit specified in SRP Section 15.4.8. However, the staff, the industry, and the international community agree that burnup degradation in the margin to low-enthalpy fuel failure is likely to be regained by application of more detailed three-dimensional (3-D) analysis methods of the fuel response to rod ejection accidents. Detailed 3-D models predict that the value of the peak fuel rod enthalpy would fall below 100 cal/gm (R.O. Meyer, R.K. McCardell, H.M. Chung, D.J. Diamond, and H.H. Scott, "A Regulatory Assessment of Test Data for Reactivity-Initiated Accidents," Nuclear Safety, Volume 37, Number 4, October–December 1996, pages 271–288). In addition, a generic analysis performed by the applicant that assumes low-enthalpy fuel failure shows that the radiological consequences of rod ejection accidents meet the acceptance criteria specified in Appendix A to SRP Section 15.4.8. As indicated in the response to RAI 440.181, the applicant's generic analysis is predicated on conservative treatment of the experimental fuel data applied to existing and planned cores operating within approved burnup limits for PWRs. Therefore, the staff concludes that, although the SRP Section 15.4.8 fuel enthalpy safety limit may not be conservative, the generic analysis provides reasonable assurance that radiological consequences of the rod ejection accident will not violate the acceptance criteria in SRP Section 15.4.8 for the AP1000 core operating within the current NRC-approved burnup limits. The staff will not accept further extension of burnup limits until additional experimental information on fuel behavior is available to demonstrate that the fuel cladding will satisfy the regulatory acceptance criteria used in the rod ejection analyses for licensing applications. Section 15.3 of this report includes the review of the radiological releases.

The applicant performed the analysis using acceptable methods. The results of the analysis show that the calculated values of peak fuel enthalpy fall below the acceptable limit specified in SRP Section 15.4.8, the calculated peak RCS pressure does not exceed the RCS emergency limits (Service Level C), and the radiological consequences meet the SRP Section 15.4.8 acceptance criteria. The staff finds that the analysis meets the acceptance criteria of SRP Section 15.4.8, with respect to the limits of the hot rod average enthalpy, RCS pressure, and radiological consequences. Therefore, the staff concludes that the analysis is acceptable.

15.2.5 Increase in Reactor Coolant System Inventory (DCD Tier 2, Section 15.5)

In DCD Tier 2, Section 15.5, the applicant considers two cases which would result in an increase in the RCS inventory. These cases are (1) an inadvertent operation of the CMTs and (2) malfunction of the chemical and control system.

15.2.5.1 Inadvertent Operation of the Core Makeup Tanks during Power Operation (DCD Tier 2, Section 15.5.1)

Operator action, a false electrical actuation signal, or a valve malfunction can cause spurious CMT operations. The DCD presents the results of the most limiting case, a CMT inadvertently actuated by operator error or a mechanical failure resulting in the opening of two valves in the CMT discharge lines. During the event, the high-3 pressurizer water-level signal actuates to trip the reactor, followed by the PRHR actuation and eventually by an "S" signal, which then actuates the second CMT. The applicant analyzed the case using the LOFTRAN code and established the following initial conditions to maximize pressurizer water level:

- The reactor power is at 102 percent of nominal, the pressure is at 344.7 kPa (50 psi) below nominal, and RCS temperature is at 3.9 °C (7 °F) below nominal.
- The pressurizer spray system and automatic rod control are operable.
- A least-negative MTC, a low (absolute) Doppler power coefficient, and a maximum boron worth are assumed.

The CMT enthalpies are maximized to minimize the cooling provided by the CMTs. The pressure drop of the CMT injection and balance lines is minimized to maximize the CMT flow injected into the primary system. In response to RAI 440.085, the applicant indicated that modeling high pressure drops through the PRHR loop minimizes the PRHR heat transfer capability. A higher pressure drop limits the PRHR flow and reduces the calculated value of the primary-side heat transfer coefficient. In addition, a maximum TS value for PRHR tube plugging and a minimum effective heat transfer area have been assumed. The assumptions using the higher CMT injection flow and a minimum PRHR heat transfer capability result in an increase in the RCS temperature and RCS expansion, thus reducing the margin to pressurizer overfilling. Therefore, the assumptions are conservative and acceptable.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it identified that the worst single failure is one of the two PRHR parallel isolation valves failing closed. In addressing the issue of a LOOP, the applicant assumed that a power loss and the resulting coastdown of the RCPs occur 3 seconds after the turbine trip.

The analysis assumes that an inadvertent opening of the CMT discharge valves, which results in the one CMT injecting borated water, initiates the event. During the transient, the reactor is tripped upon receipt of the high-3 pressurizer-level signal. Following reactor trip, the reactor power drops and average RCS temperature decreases with subsequent coolant shrinkage. At about the same time of the reactor trip, the turbine is tripped and, after a 3-second delay, a consequential LOOP is assumed, and the RCPs are tripped. The cold-leg temperature increases, resulting in an increased CMT injection rate, because of the increased driving head from the density decrease in the pressure balance line. The CMT injection makes up the RCS shrinkage, and, within 1 minute after actuation of the high-3 pressurizer-level signal, the high-3 pressurizer-level setpoint is once again reached. Initiation of the PRHR, with appropriate delay time, is then assumed. The primary and secondary pressures increase initially because of the assumed unavailability of the non-safety-related control systems, but eventually decrease as the PRHR removes the core decay heat. At about 1.39 hours, the PRHR heat flux matches the core decay heat. During this period, the pressurizer level continues to slowly increase until the CMT recirculation decreases sufficiently to limit the mass addition to the RCS. After about 3.43 hours into the transient, the cold-leg temperature ("S") setpoint is reached, and the second CMT is actuated. The pressurizer level initially shrinks from the addition of cold borated water. As the CMT continues to add water to the primary system, the pressurizer level begins to increase. At 3.69 hours, the first CMT stops recirculation. At 6.06 hours, the PHRH heat flux approaches the core heat flux. The CMTs stop recirculating at 8.52 hours into the transient.

The staff finds that the applicant used the LOFTRAN code for the analysis and adequately identified the limiting case. The results of analysis show that no RCS water is relieved through the pressurizer safety valves as a result of the transient. In addition, the calculated minimum DNBR remains above the safety limit value, and the RCS and SG pressures remain below 110 percent of their respective design pressures. The staff determines that the analysis meets the acceptance criteria of SRP Section 15.5.1 with respect to the pressure limit and core DNBR safety limit and, therefore, concludes that the analysis is acceptable.

15.2.5.2 CVCS Malfunction that Increases Reactor Coolant Inventory (DCD Tier 2, Section 15.5.2)

A CVCS malfunction may result in an event that increases RCS inventory. Operator action, an electrical actuation signal, or a valve failure may cause the CVCS to malfunction. The DCD presents the results of the most limiting case, the CVCS malfunction caused by an operator error, resulting in the startup of two CVCS pumps to deliver the flow to the RCS. The applicant analyzed CVCS malfunction cases using the LOFTRAN code and established the following initial conditions to maximize the pressurizer water level:

- The reactor power is at 102 percent of nominal, the pressure is 344.7 kPa (50 psi) above nominal, and the RCS temperature is at 3.6 °C (6.5 °F) above nominal.

- The pressurizer spray system is operable.
- A least-negative MTC, a low (absolute) Doppler power coefficient, and a maximum boron worth are assumed.
- The initial boron concentration is chosen on the basis of an iterative analysis process, such that the limiting case bounds the case that models explicit operator actions after the reactor trip.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it identified that the worst single failure is one of the two PRHR parallel isolation valves failing closed. In addressing the issue of a LOOP, the applicant assumed that a power loss and resulting coastdown of the RCPs occur 3 seconds after the turbine trip.

The analysis assumes that a CVCS malfunction that results in injection from two CVCS pumps initiates the event. As the CVCS injection flow increases RCS inventory, the pressurizer water volume begins increasing while the primary system cools down. The RCS temperature decreases to reach the low cold-leg temperature setpoint and actuates an "S" signal, resulting in a reactor trip. Following the reactor trip, the turbine is tripped, and, after a 3-second delay, a consequential LOOP is assumed, and the RCPs are tripped. Soon after the reactor trip, main feedwater lines, steamlines, and the CVCS are isolated. After a delay of 12 seconds following the "S" signal, the CMT discharge valves open, and 5 seconds afterward the PRHR HX is actuated. The operation of the PRHR HX and CMTs cools down the plant. At about 4.09 hours into the transient, the PRHR heat flux matches the core decay heat, and at 5.61 hours the CMTs stop recirculating.

The staff finds that the applicant used the LOFTRAN code for the analysis with adequate inputs and appropriately identified the limiting case, and the results show that no RCS water is relieved from the pressurizer safety valves. In addition, the calculated minimum DNBR remains above the safety limit values, and the RCS and SG pressures remain below 110 percent of their respective design pressures. The staff determines that the analysis meets the acceptance criteria of SRP Section 15.5.2 with respect to the pressure limit and core DNBR safety limit. Therefore, the staff concludes that the analysis is acceptable.

15.2.6 Decrease in Reactor Coolant Inventory (DCD Tier 2, Section 15.6)

In DCD Tier 2, Section 15.6, the applicant provided an analysis of events that may decrease the RCS inventory. These events include (1) an inadvertent opening of a pressurizer safety valve or inadvertent operation of the automatic depressurization system (ADS), (2) a break in an instrument line or other lines from the reactor coolant boundary that penetrate the containment, (3) an SG tube failure, and (4) a LOCA resulting from a spectrum of postulated piping breaks within the RCPB. The following sections discuss the applicant's analysis and the staff's evaluation.

15.2.6.1 Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the Automatic Depressurization System (DCD Tier 2, Section 15.6.1)

An accidental depressurization of the RCS may occur as a result of an inadvertent opening of a pressurizer safety valve or ADS valves. During the transient, the RCS pressure rapidly decreases and, in turn, causes a decrease in power because of the moderator density reactivity feedback. The pressurizer level may eventually drop far enough to cause a reactor trip on a low pressurizer-level signal.

The ADS consists of four stages of depressurization valves, which are interlocked such that Stage 1 is initiated first, with subsequent stages actuated only after previous stages have been actuated. The AP1000 design prohibits opening of the fourth stage valves while the RCS is at nominal operating pressure. For inadvertent operation of the ADS valves, the applicant considered an opening of both first stage ADS flowpaths to be the limiting case, because operation of these valves results in a greater depressurization rate than ADS Stages 2 and 3 valves given the shorter first stage ADS valve opening time.

The applicant has also analyzed an inadvertent opening of the pressurizer safety valve. The flow area of the pressurizer valve is smaller than the combined two ADS Stage 1 valves; however, the safety valves open more rapidly than the ADS valves.

Normal reactor control systems are assumed not to function. The rod control system is assumed to be in automatic mode in order to maintain the core at full power until the reactor trip protection function is reached.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it determined that no single active failure in these systems or equipment adversely affected the consequences of the event. In addressing a LOOP, the applicant assumed that a power loss and resulting coastdown of the RCPs occur 3 seconds after the turbine trip. The analysis shows that a LOOP has no effect on the calculated minimum DNBR, because a rapid decrease in the heat flux after the reactor trip compensates for the decrease in the RCS flow caused by the LOOP (which would follow a turbine trip), and the minimum DNBR occurs before initiation of a LOOP.

To perform the analysis of these events, the applicant used LOFTRAN for the transient response calculation, FACTRAN for the heat flux calculation, and VIPRE-01 for the DNBR calculation. The DNBR calculations for these RCS valve opening events are performed using the revised thermal margin procedure in WCAP-11397-P-A. Initial core power, RCS pressure, and RCS temperature are assumed to be at their nominal values, consistent with steady-state, full-power operation.

The staff finds that the applicant analyzed the events using acceptable methods. The analysis shows that the overtemperature delta T reactor trip signal provides adequate protection against the RCS depressurization events. The calculated DNBR remains above the safety limiting value, and the RCS pressure remains less than 110 percent of the design pressure throughout the transients. The staff determines that the analysis meets the acceptance criteria of SRP

Section 15.6.1 with respect to the pressure and core safety DNBR limits and, therefore, concludes that it is acceptable.

15.2.6.2 Failure of Small Lines Carrying Primary Coolant Outside Containment (DCD Tier 2, Section 15.6.2)

The reactor coolant may be released directly from a break or leak outside containment in a CVCS discharge line or sample line. The applicant's analysis has identified that the worst case event is the double-ended break of the sample line between the isolation valve outside the containment and the sample panel. This sample line break results in the largest release of reactor coolant outside containment. The sample line orifices limit the maximum breakflow to 8.2 L/s (130 gpm).

Both the isolation valves inside and outside containment are open only during sampling, and the loss of sample flow will provide an indication of the break to plant operators. A break in a sample line releases radioactivity which will actuate area and air radiation monitors. Because the operator sees multiple indications, the applicant assumed that, 30 minutes after initiation of a break, the operator would isolate the sample line and terminate further release of primary fluid discharged to the atmosphere. The assumed operator action delay time of 30 minutes is consistent with the current operating plant design-basis analysis of a break of a small line outside containment and, therefore, is acceptable.

The assumptions used for analysis of this event are adequate and acceptable, and the scenario described in DCD Tier 2, Section 15.6.2, ensures that the applicant has considered the most severe failure of piping carrying the primary coolant outside containment. In addition, the radiological releases fall within the 10 CFR 50.34(a)(1)(ii)(D)(*1*) limits. Thus, the staff determines that the analysis meets the SRP Section 15.6.2 acceptance criteria. Therefore, the staff concludes that the analysis is acceptable. Section 15.3 of this report discusses the staff's evaluation of the radiological release calculations.

15.2.6.3 Steam Generator Tube Rupture (DCD Tier 2, Section 15.6.3)

The SGTR accident is defined as a penetration of the barrier between the RCS and the main steam system. The failure of an SG U-tube may cause this accident.

The analysis for the SGTR event consists of two parts, SG overfill calculation and the calculation of the SG mass releases used to evaluate the radiological consequence.

The applicant performed an analysis with LOFTTR2 to demonstrate that the AP1000 design features can prevent the SG from overfilling with water. To maximize the SG water increase, the applicant identified the limiting single failure as the failure of the startup feedwater control valve to throttle flow when nominal SG level is reached. Other conservative assumptions maximizing the SG secondary water inventory include a high initial SG level, minimum initial RCS pressure, LOOP, maximum CVCS injection flow, maximum pressurizer heater addition, maximum startup feedwater flow, and minimum startup feedwater delay time. The results of the analysis demonstrate that the AP1000 protection system and passive system design features will prevent the SG from overfilling with water during an SGTR.

For the SG mass release calculation, the applicant performed the SGTR analysis using the LOFTTR2 code for a case with complete severance of a single SG tube. At the initiation of an SGTR, the reactor is assumed to be at nominal full power. The initial secondary mass is assumed at nominal SG mass with an allowance for uncertainties. A LOOP is assumed at the start of the event, because tripping the RCPs (resulting from a LOOP) has been determined to maximize flashing of primary-to-secondary break flow, consequently maximizing radiological releases. The LOOP is assumed to trip the reactor. Consistent with the assumption of a LOOP, main feedwater pump coastdown occurs after the reactor trip, and no startup feedwater is assumed in order to minimize SG secondary inventory and, thus, maximize secondary activity concentration and steam release. The CVCS pumps are assumed to be loaded onto the diesel generators. Maximum CVCS flows and the pressurizer heater addition are assumed at the initiation of the event (even though offsite power is not available) to maximize primary-to-secondary leakage. The CVCS is assumed to isolate on the high-2 SG narrow-range level setpoint. Because the failure of the steam dump system would result in a steam release from the SG power-operated relief vales (PORVs) to the atmosphere following the reactor trip, the steam dump system is assumed to be inoperable to maximize the radiological releases.

The applicant has considered plant systems and equipment, discussed in DCD Tier 2, Section 15.0.8, that are available to mitigate the effects of the event, and it identified that the most limiting single failure is a failed-open PORV on the affected SG. The applicant assumed that the single failure occurs coincidently with the low-2 pressurizer-level signal, maximizing the integrated RCS-to-secondary break flow. The automatic closure of the associated block valve on a low steamline pressure protection system signal isolates the SG PORV.

The analysis shows that after the reactor trip, low pressurizer pressure generates a safeguard "S" signal. The "S" signal results in CMT actuation and PRHR system actuation. Opening the SG PORVs and operation of the PRHR and CMTs decrease the primary and secondary pressures. When the secondary pressure decreases to the low steamline pressure setpoint, the steamline isolation valves and SG PORV block valves are closed. Following closure of the block valves, the primary and secondary pressures and faulted SG secondary water volume increase as breakflow accumulates. This increase continues until the SG secondary level reaches the high-2 narrow-range level and isolates the CVCS pump. With continued RCS cooldown and depressurization provided by the PRHR system, primary pressure decreases to match the secondary pressure. At about 6.70 hours after the transient, the breakflow terminates, and the system reaches a stable condition. The analysis shows that the PRHR can remove the core decay heat and prevent the unaffected PORV from opening. During the transient, the CMTs remain full, ADS actuation does not occur, and the SG does not overfill with water.

During an SGTR, the RCS depressurizes as a result of the primary-to-secondary leakage through the ruptured SG tube. The depressurization reduces the calculated DNBRs. The analysis shows that the depressurization before reactor trip for the SGTR is slower than for the RCS depressurization events discussed in Section 15.2.6.1 of this report. Following a reactor trip, the DNBR rapidly increases. Thus, the staff's conclusion for the event discussed in Section 15.2.6.1 of this report also applies to the SGTR event, in that the calculated DNBR remains above the safety limit.

For this analysis, the applicant used the LOFTTR2 computer code together with conservative and acceptable assumptions to maximize the primary-to-secondary leakage. The results of the analysis show that the SG will not overfill with water, the maximum RCS will not exceed 110 percent of design pressure, and the minimum DNBR will remain greater than the safety DNBR limit. In addition, the analysis shows that the PRHR and CMTs can achieve LTC, and the radiological releases will remain within the limits of 10 CFR 50.34(a)(1)(ii)(D)(*1*). The staff finds that the SGTR analysis meets the acceptance criteria of SRP Section 15.6.3 with respect to the pressure and core safety DNBR limits and, therefore, concludes that the analysis is acceptable. Section 15.3 of this report discusses the staff's evaluation of the radiological release.

15.2.6.4 Spectrum of Boiling-Water Reactor Steam System Piping Failure Outside Containment (DCD Tier 2, Section 15.6.4)

This section of the DCD does not apply to the AP1000 design, which is a PWR design.

15.2.6.5 Loss-of-Coolant Accident (DCD Tier 2, Section 15.6.5)

In DCD Tier 2, Section 15.6.5, Westinghouse presents the LOCA analysis results. The applicant's analyses examine SBLOCAs, LBLOCAs, and post-LOCA LTC.

The applicant's LOCA analyses meet the following acceptance criteria for the calculated ECCS performance:

- The calculated peak cladding temperature (PCT) is less than 1204 °C (2200 °F).

- The calculated total oxidation of the cladding is within 0.17 times the total cladding thickness before oxidation.

- The calculated total amount of hydrogen generated is less than 0.01 times the hypothetical amount that can be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, reacts.

- Any calculated changes in core geometry will be such that the core remains amenable to cooling.

- After any calculated successful initial operation of the ECCS, the calculated core temperature will be maintained at an acceptably low value, and decay heat will be removed for the extended time required by the long-lived radioactivity remaining in the core.

These criteria are established to provide significant margin for ECCS performance following a LOCA. The staff finds that these acceptance criteria are consistent with the requirements of 10 CFR 50.46(b)(1)–(b)(5) for ECCS performance and, therefore, are acceptable.

15.2.6.5.1 Small Breaks

The AP1000 is designed to keep the reactor core cooled and covered with water by means of passive safety systems which do not require the start and operation of pumps to provide makeup water. No operator action is required to actuate and control the passive protective systems. Active systems using pumps are also available for activation and control by the operator in the event of an SBLOCA. However, the design-basis analysis of the AP1000 design does not credit the operation of these active systems.

During an SBLOCA, the AP1000 reactor system will depressurize to the pressurizer low-pressure setpoint, initiating a reactor trip signal. With further reduction in reactor system pressure, the pressurizer low-pressure setpoint will be reached to actuate an "S" signal. The "S" signal causes the opening of valves in the discharge of the CMTs and PRHR. The CMTs will immediately begin to circulate borated water into the RV downcomer by way of the direct vessel injection (DVI) line. Water will also begin to circulate through the PRHR HX to ensure decay heat removal. As the reactor system drains, the CMTs provide a source of water to replenish that lost out of the break. The "S" signal will also trip the RCPs, which will retain water in the lower elevations of the reactor system and around the core and will minimize the loss of water from the break.

As the CMTs drain, signals are sent to the ADS valves to open in a prescribed sequence. The first three stages of ADS, which are located at the top of the pressurizer, will begin to sequence open when the CMT water volume drops to 67.5 percent. The ADS Stage 4 valve (ADS-4) begins its open sequence when the CMT water volume drops to 20 percent.

The action of the break, PRHR, and ADS-1, 2, and 3 causes the reactor pressure to decrease. When the pressure reaches approximately 4.83 MPa (700 psig), the accumulator tanks, which contain borated water pressurized with nitrogen, will inject into the RV by way of the DVI lines. Following actuation of the ADS-4, the reactor system pressure will approach that of the containment, permitting borated water from the IRWST to flow by gravity into DVI lines and into the RV.

In DCD Tier 2, Section 15.6.5.4B.2, "Small-Break LOCA Analysis Methodology," the applicant described the three elements of the AP1000 SBLOCA evaluation model as the NOTRUMP computer code, the NOTRUMP homogeneous sensitivity model, and the CHF assessment during accumulator injection. As described in the following discussion, the applicant applied the three elements in the analyses for the AP1000 design. The results demonstrate that the design of the AP1000 adequately mitigates the consequences of postulated design-basis SBLOCA events. Section 21.6.2 of this report discusses the staff's evaluation and acceptance of the NOTRUMP code and the SBLOCA evaluation model for the AP1000.

The applicant performed SBLOCA analyses using the NOTRUMP computer code for the period immediately after the break occurs until IRWST flow is fully established to the reactor core. After this time, the reactor is considered to be in LTC. Section 15.2.7 of this report discusses the applicant's analyses for LTC. The NRC staff conducted its evaluation of SBLOCA for the AP1000 design in accordance with SRP Section 15.6.5 to ensure that the acceptance criteria listed in 10 CFR 50.46 will not be exceeded.

NOTRUMP calculates the flow of steam and water in one dimension with variable nodalization. The code considers thermodynamic nonequilibrium between the steam and water phases. Code features include flow regime-dependent drift-flux calculations with counter-current flooding limitations, mixture-level tracking logic in multiple-stacking fluid nodes, and regime-dependent heat transfer correlations.

The NOTRUMP analyses were made conservative by assuming decay heat at 120 percent of the ANS 5.1-1971 Standard, as required by Appendix K to 10 CFR Part 50. The single failure of one of the four ADS-4 valves was assumed. This failure was determined to be the most limiting for the AP1000 design. For most of the NOTRUMP analyses, the containment was assumed to remain at atmospheric pressure. The use of atmospheric pressure maximizes pressure losses out of the three ADS-4 valves assumed to remain operable, which delays the time when sustained inventory injection to the RV from the IRWST can occur. DCD Tier 2, Section 15.0.8, discusses the plant systems and equipment that are assumed to be available to mitigate the effects of the event.

In the DCD, the applicant described SBLOCA analyses for the following cases:

- the inadvertent opening of both 10.16-cm (4-in.) ADS-1 valves (atmospheric containment pressure)
- a cold-leg break of 5.08 cm (2 in.) equivalent diameter in the loop without the pressurizer (atmospheric containment pressure)
- the double-ended rupture of a DVI line (atmospheric containment pressure)
- the double-ended rupture of a DVI line (138 kPa (20 psia) containment pressure)
- a cold-leg break of 25.4 cm (10 in.) equivalent diameter (atmospheric containment pressure)

NOTRUMP did not calculate any of these breaks to cause core uncovery or core heatup. For the analysis of the 25.4-cm (10-in.) cold-leg break, NOTRUMP calculated the core to become highly voided during the early part of the accident when the core stored energy was removed. NOTRUMP does not have a detailed core heatup model for hot channel evaluation. To evaluate the core heating that might occur, the applicant performed a conservative heatup calculation in which that portion of the core that might experience critical heat flux was allowed to heat adiabatically until the combined flow from the two accumulators reduced the core void fraction. This calculation resulted in a PCT of 744 °C (1370 °F), which is much less than the 1204 °C (2200 °F) limit in 10 CFR 50.46. For break sizes larger than 25.4 cm (10 in.) equivalent diameter, even more core voiding and core heatup would be expected. The large break sizes, evaluated in Section 15.2.6.5.2 of this report, would bound the breaks discussed above.

In the AP1000, the hot-legs enter the RV at a lower elevation than do the cold-legs. A small break in a hot-leg might lead to a lower RV inventory than a break in a cold-leg of the same size. In RAI 440.098, the staff requested the applicant to perform additional SBLOCA analyses, including hot-leg breaks, for the AP1000 design. In response, the applicant provided the NOTRUMP predictions for the following small breaks:

- a 5.08-cm (2-in.) cold-leg break in the loop with the pressurizer (atmospheric containment pressure)
- a 5.08-cm (2-in.) hot-leg break in the loop without the pressurizer (atmospheric containment pressure)
- the double-ended break of a cold-leg pressure balance line to a CMT (atmospheric containment pressure)

None of these break sizes resulted in core uncovery. The staff concludes that the applicant has evaluated a sufficient small-break spectrum.

The double-ended severance of a DVI line represents a limiting sequence for SBLOCA analysis, because the water from one of the two accumulators, one of the two CMTs, and one of the two IRWST injection lines would not reach the RV, but would spill into the containment. For this reason, the staff concentrated much of the review effort on this postulated accident.

The staff has reservations on the ability of the NOTRUMP code to conservatively predict liquid entrainment within the upper plenum, hot-legs, and ADS-4 valves. If too little liquid entrainment were assumed, this liquid would be available to flow back into the core and provide unrealistic core cooling, and depressurization of the reactor system by the ADS-4 would be artificially enhanced. Both these effects would not be conservative for safety analysis. Westinghouse addressed this concern by performing an analysis for the double-ended DVI line break in which all liquid leaving the core was set at the same velocity as that of the steam (homogeneous flow). Using the homogeneous flow assumption, all liquid which reached the upper plenum would be swept out toward the ADS-4. The homogeneous analysis did not predict significant core uncovery. However, it predicted a lower minimum core water mass, compared to the nonhomogeneous case. The homogeneous analysis for a postulated double-ended DVI line break is part of the small break evaluation model for the AP1000 design.

As part of the validation of NOTRUMP, as discussed in Section 21.6.2 of this report, Westinghouse compared NOTRUMP predications with test data from the Advanced Plant Experiment (APEX)-1000 test facility. For most phenomena, the code compared well with the test data. However, the code was found to be nonconservative for prediction of water in the core in the early part of the tests simulating double-ended DVI line breaks. For this reason, the applicant performed an analysis of the double-ended DVI line break for the AP1000 using the Chang critical heat flux correlation (Chang, S.H., et al., "A Study of Critical Heat Flux for Low Flow of Water in Vertical Round Tubes Under Low Pressure," Nuclear Engineering and Design, July 1991). The Chang correlation analysis demonstrated that the core will remain cooled during this period. Use of the Chang correlation to demonstrate core cooling for the double-ended DVI line break is part of the small break evaluation model for the AP1000 design.

In performing the double-ended DVI break analyses (including the homogeneous assumption analysis), the applicant took credit for the ADS-4 and the elevated containment pressure that would exist as a result of the energy added to the containment atmosphere by the break. Use of an elevated pressure increases the relieving capacity of the ADS-4 and shortens the time before IRWST injection begins. The applicant believes that 137.9 kPa (20 psia) is the minimum pressure that will occur within the containment building following the occurrence of a double-ended DVI line break during the time period covered by the NOTRUMP analysis. In calculating the minimum containment pressure, the applicant used the WGOTHIC code, which the NRC staff has reviewed, as discussed in Section 21.6.5 of this report. After discussions with the NRC staff, the applicant made a series of conservative assumptions for computing low containment pressures. The AP1000 minimum pressure and LTC models incorporate the following conservative assumptions, with the detailed maximum pressure model as the reference point:

- The containment net volume was increased by a factor of 1.1.
- The containment shell and the passive containment cooling system (PCS) heat structure areas were increased by a factor of 1.1.
- The remaining heat structure areas were increased by a factor of 2.1.
- The Uchida correlation with a multiplier of 1.2 was used for passive heat structures (non-PCS structures) throughout the accident.
- The PCS heat and mass transfer correlation multipliers were appropriately biased to account for the uncertainty in the experiential database, and forced convection was not included on the PCS inner surface.
- Heat transfer in dead-ended compartments below the operating deck was not turned off at the end of blowdown.
- The air gap between the steel and the concrete was reduced to zero, from the 20-mil thickness used in the maximum pressure calculation.
- The material properties for steel, concrete, air, and the inorganic zinc coating were biased high for conservatism.
- Heat transfer credit for the PCS was set to start at the beginning of the accident, earlier than was assumed for the maximum pressure calculation.
- Westinghouse maintained its treatment of ECCS spillage as implemented in 1979 (with the acceptance of the WGOTHIC breakflow model for this evaluation).
- The containment purge system was assumed to be operating at the start of the accident and isolated on a high-pressure signal.
- The initial and boundary conditions for the containment, the PCS water, and the environment were set to minimize the calculated pressure.

- The operators were assumed to actuate the non-safety-related air coolers 10 minutes after the break occurred.

Westinghouse used similar assumptions to compute the minimum containment pressures for ECCS evaluation of operating plants. The NRC staff reviewed the minimum back pressure calculation and concludes that they are an acceptable adaptation of the guidelines of SRP Section 6.2.1.5, "Minimum Containment Pressure Analysis for Emergency Core Cooling System Performance Studies," and that the results are acceptable for use in the ECCS evaluation for the AP1000 design.

Although the core was predicted to remain covered following a double-ended DVI line break, even if the containment pressure is maintained at 101.4 kPa (14.7 psia) as a boundary condition for the NOTRUMP calculation, the applicant considered the 137.9 kPa (20 psia) containment back pressure boundary condition case to be the base case for the design basis. The LTC analysis for the design-basis double-ended DVI line break using WCOBRA/TRAC is initialized from the NOTRUMP analysis using the 137.9 kPa (20 psia) back pressure.

As an additional check on the NOTRUMP results obtained by the applicant, the staff performed a series of audit calculations of SBLOCAs for the AP1000 using the RELAP5 computer code. The staff developed RELAP5, an advanced T-H simulation tool. The RELAP5 analyses used conservative assumptions similar to those used by the applicant in the NOTRUMP analyses. Decay heat was set at 120 percent of the ANS-5.1-1973 Standard. The ANS-5.1-1973 decay heat standard is equivalent to the ANS-5.1-1971 standard used in the NOTRUMP analyses. The single failure of one of the four ADS-4 valves was assumed. The containment was assumed to remain at atmospheric pressure. The core model in the RELAP5 analyses is somewhat more detailed than the NOTRUMP core model, in that a hot rod is modeled with a higher heat flux than the average core. The increased heat flux of the hot rod allows for the assessment of the possibility of fuel cladding heatup following a DNB condition or core uncovery event.

The staff performed audit calculations for the following cases:

- the inadvertent opening of both 10.16-cm (4-in.) ADS-1 valves
- a cold-leg break of 5.08-cm (2-in.) equivalent diameter in the loop without the pressurizer
- a cold-leg break of 8.89-cm (3.5-in.) equivalent diameter in the loop without the pressurizer
- a hot-leg break of 8.89-cm (3.5-in.) equivalent diameter in the loop with the pressurizer
- the double-ended rupture of a DVI line
- a cold-leg break of 25.4-cm (10-in.) equivalent diameter

None of the breaks analyzed by the staff using RELAP5 resulted in core uncovery or cladding heatup. RELAP5 calculated approximately the same minimum core water mass for all break sizes. However, the analysis predicted slightly less core water mass for the double-ended DVI line break than for the other breaks.

Operating PWRs do not have ADS valves or a PRHR to depressurize and cool the RCS following a LOCA. Operating PWRs must cool and depressurize the reactor system using the SGs to remove decay heat. Under this scenario, it has been postulated that water from steam condensation within the SG tubes might flow into the lower cold-leg elevations and into the core. The water derived from steam condensation would not be borated, so that the entry of this water into the core might cause an increase in core power. The NRC staff does not believe deboration will occur during an SBLOCA for the AP1000 design. Section 15.2.8 of this report evaluates this issue.

Based on the foregoing considerations, the staff concludes that the applicant's analyses for a spectrum of small piping breaks in the reactor pressure boundary are acceptable and meet the requirements of 10 CFR 50.46 and Appendix K to 10 CFR Part 50, and that the calculated performance of the passive ECCS following a postulated SBLOCA is acceptable.

15.2.6.5.2 Large Breaks (DCD Tier 2, Section 15.6.5.4A.8)

The applicant performed the LBLOCA analyses using the WCOBRA/TRAC code as documented in WCAP-12945. WCOBRA/TRAC is the Westinghouse's BE T-H computer code used to calculate T-H conditions in the reactor system during blowdown and reflood of a postulated LBLOCA. This code consists of the BE features needed to satisfy the requirements of 10 CFR 50.46(a)(1)(i) for a realistic code.

In addition, the applicant used WCOBRA/TRAC to analyze the post-LOCA LTC of the AP1000, including decay heat assumptions from 10 CFR Part 50, Appendix K. Section 15.2.7 of this report discusses the staff's evaluation and conclusions for the LTC.

The applicant used the WCOBRA/TRAC code to perform the LBLOCA analysis. DCD Tier 2, Table 15.6.5-4, lists the initial plant physical configuration, power-related parameters, initial fluid conditions, and RCS boundary conditions used to determine the most limiting break size. These initial conditions are determined from the applicant's sensitivity study of the worst-case set of combinations that result in the highest limiting calculated PCT. To determine the limiting break case, the applicant performed parametric studies for the PCT with respect to bounding initial conditions and associated uncertainties using the methods described in WCAP-14171, to calculate the 95th percentile PCT. The results of the analysis show that the double-ended cold-leg guillotine break results in a maximum PCT and is the limiting case. In all cases analyzed, the bounding core design values of Fq = 2.60 and FdH = 1.65 are applied to the hot rod, at 102 percent of nominal core power. Finally, it was noted that the search for the limiting LBLOCA included the hot-leg break and the cold-leg limiting split break.

The applicant considered the plant systems and equipment that are available to mitigate the effects of the accident, as discussed in its response to RAI 440.097, Revision 1, and identified the limiting single failure as a failure of one CMT discharge valve to open. In modeling the

CMTs and accumulators, the applicant minimized the capability to add borated water by assuming the failure of one CMT discharge valve to reflect the limiting single failure.

The applicant presented the results of the LBLOCA analyses in DCD Tier 2, Tables 15.6.5-5 through 15.6.5-8, and Figures 15.6.5.4A-1 through 15.6.5.4A-12. The applicant submitted additional information in its response to RAI 440.097, Revision 1, Table 15.6.5-8, and Revision 1 response to RAI 440.097, Figures 440.097R1-1 through 440.097R1-3. Following an LBLOCA, the reactor trip actuates on a low-pressurizer pressure trip signal. The LBLOCA analysis does not credit the insertion of the control rods. Within a few seconds after the initiation of an LBLOCA, an "S" signal actuates on the containment high-2 pressure. As a result, after appropriate delays, the PRHR and CMT isolation valves open, and containment isolation occurs. The rapid depressurization of the RCS during an LBLOCA leads to the initiation of accumulator injection early in the transient. The accumulator flow reduces CMT delivery to the degree that the CMT level does not reach the ADS Stage 1 valve actuation setpoint until after the accumulator tank empties, following completion of the blowdown phase. The applicant's calculations continue until the fuel rods are quenched.

The applicant used the WCOBRA/TRAC models to perform the LBLOCA analyses with calculated PCT uncertainties derived from the effects of model-related parameters, while the initial condition-related parameters used in the analyses are bounding and conservative.

The applicant addressed the limitations in WCOBRA/TRAC relating to the PCT for values greater than 940 °C (1725 °F). Staff review of the sensitivity calculations required by the code limitation indicates that the results reinforce the conservatism of the calculation.

15.2.6.5.2.1 Summary of the Large Break LOCA Analysis Results

As per 10 CFR 50.46, the AP1000 LBLOCA analysis shows a high level of probability that the following criteria will be met:

- The calculated PCT will not exceed 1204 °C (2200 °F).
- The calculated maximum cladding oxidation will not exceed 0.17 percent of the total cladding thickness before oxidation.
- The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam will not exceed 1 percent of the amount that would be generated if the entire cladding metal surrounding the fuel (excluding the cladding surrounding the plenum volume) were oxidized.
- The calculated changes in core geometry are such that the core remains amenable to cooling.
- After successful initial operation of the ECCS system, the core temperature will be maintained at an acceptably low value, and decay heat will be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

The calculated results of the AP1000 LBLOCA satisfy the requirements of 10 CFR 50.46 and, therefore, are acceptable.

15.2.7 Post-LOCA Long-Term Cooling (DCD Tier 2, Section 15.6.5.4C)

This analysis establishes that (1) the core remains cooled for the duration of the LTC phase, (2) the boron concentration in the core keeps the core noncritical, and (3) boron precipitation will not obstruct core coolant flow.

15.2.7.1 Double-Ended Direct Vessel Injection Line Break

The applicant selected a double-ended guillotine break of the DVI line for the LTC evaluation. The double-ended DVI (DEDVI) line break is the most limiting LTC case, in the sense that it maximizes the decay heat generation rate and minimizes the cooling water injection head. The case analyzed is the continuation of an SBLOCA. Maximum design resistance is applied for the ADS-4 flowpath, the IRWST injection, and the containment recirculation. Failure of one of the two ADS-4 valves in the PRHR loop is assumed. ADS-1, 2, and 3 valves are not modeled here, because they do not practically impact depressurization with the ADS-4 valves opened.

The applicant used WCOBRA/TRAC for the LTC analysis. As described in Section 21.6.4 of this report, the staff has evaluated WCOBRA/TRAC and found it to be acceptable for the AP1000 LTC analysis. The LTC analysis uses a detailed nodalization model, which includes 4 radial channels and 17 axial nodes in each channel to represent the AP1000 core.

Initial conditions of the RCS liquid inventory and temperatures are taken from the NOTRUMP DEDVI case to initiate the calculation shortly after IRWST injection begins, and it proceeds until achievement of a quasi-steady state. At this time, the calculated results are independent of the initial conditions. The WCOBRA/TRAC calculation proceeds using boundary conditions from a corresponding WGOTHIC analysis and is carried to 10,000 seconds, until establishment of a quasi-steady-state sump recirculation. The minimum containment flood level for this LTC transient is 32.86 m (107.8 ft)(from the plant reference elevation), which is sufficient to inject coolant into the RV through the broken DVI line. Likewise, the IRWST also provides sufficient head to inject water through the intact DVI nozzle.

In the downcomer, the water level is about 5.49 m (18 ft)(from the bottom of the core), while the core collapsed level is about 2.44 m (8 ft). Boiling in the core produces steam and a two-phase mixture, which flows into the upper plenum. The boiling process, coupled with the changes in the steam quality exiting the ADS-4 lines, causes pressure variations, which in turn cause liquid flow variations entering the bottom of the core. This also results in liquid and vapor flow variations at the top of the core. The void fraction at the uppermost two nodes is about 0.8. Two-phase mixture continuously flows into the hot-legs, which, on average, have a collapsed liquid level of more than 50 percent. The exit flow rates through the pressurizer- and nonpressurizer-side ADS-4 valves are about 22.68 kg/s and 45.36 kg/s (50 lbm/s and 100 lbm/s), respectively. The broken DVI line indicates a small outward flow at the beginning of the transient, which reverses and reaches about 22.68 kg/s (50 lbm/s) at the quasi-steady state. The intact DVI line injects about 77.11 kg/s (170 lbm/s) at the start of the transient and diminishes to about 29.48 kg/s (65 lbm/s) at the quasi-steady state. The WCOBRA/TRAC analysis demonstrated that the void fraction in the top node is 0.8, and therefore the core is wetted. The peak clad temperature for the hot rod follows saturation temperature within -12.2 °C (10 °F), indicating that core uncovery and temperature excursion do not occur during LTC.

A variant of this transient for a containment pressure of 101.4 kPa (14.7 psia) was calculated using the window method and starting at 6500 seconds. The lower containment pressure creates a higher volume of steam for the same decay heat. The reduction in containment pressure coincides with the switchover to containment recirculation. The results also show that the core remains covered, with PCTs remaining very near the saturation level.

15.2.7.2 DEDVI Break and Wall-to-Wall Floodup—Containment Recirculation

The case of DEDVI break and wall-to-wall floodup with containment recirculation is a more limiting case, in that it assumes that all of the spaces beneath the sump level are flooded, corresponding to the minimum possible water level and the minimum injection head through the broken DVI line. Flooding of the dry compartments is conservatively estimated to take 14 days. The decay heat source is estimated for this time. DCD Tier 2, Section 15.6.5.4C.2, describes the calculations for the initial conditions for the window at floodup conditions, including the assumptions for an ADS-4 failure and 101.4 kPa (14.7 psia) containment pressure.

This LTC calculation was performed using the window mode methodology. The calculation was performed with the continuous mode until establishment of a quasi-steady state at about 400 seconds of transient time. The downcomer collapsed liquid level varies from 7.0 m to 7.6 m (23 ft to 25 ft), while the collapsed liquid level in the vessel is about 4 m (13 ft). Pressure spikes from the boiling process and changes in steam quality out of the ADS-4 lines cause injection liquid flow rate variations through the broken and intact DVI lines of an average value of approximately 22.68 kg/s (50 lbm/s). The top two nodes have average void fractions of about 0.8 and 0.7, respectively. The collapsed liquid level in the hot-leg is about .5 m (1.7 ft), while the peak clad temperature of the hot rod remains close to the saturation temperature. The vapor mass flow rate out of the core is about 1.6 kg/s (3.5 lbm/s), and the liquid flow rate is about 45.36 kg/s (100 lbm/s). This liquid flow out of the vessel is more than sufficient to remove excess boron. As described in Section 15.2.7.6 of this report, the staff also performed an independent evaluation of the AP1000 LTC behavior, which concludes that the boric acid concentration will not reach precipitation limits. In summary, the wall-to-wall flooding case with the lowest injection head keeps the core cooled and provides more than adequate liquid flow to preclude boron concentration in the core.

15.2.7.3 Post Accident Boron Concentration

Westinghouse performed an evaluation of the potential for boron concentration to build up in the core following a LOCA and during LTC. The evaluation considered short- and long-term intervals which correspond to the times before and after ADS actuation. In the short term, the time is relatively limited and continuous flow exists. For boron to concentrate in the vessel, significant amounts of borated water must be dumped into the vessel. This takes place when the cold-legs void, and the CMTs begin to inject. At a CMT level of 20 percent, the ADS-4 actuates. In this time interval, favorable conditions for boron concentration do not occur. The applicant's calculations show that a 2-in. break LOCA requires less than 16 minutes until the ADS is actuated. For larger breaks, the time is shorter. At the decay heat levels of the AP1000, the buildup of significant concentration requires more than 3 hours. In the long-term interval, once the ADS-4 is actuated, liquid outflow limits the boron concentration in the core. These calculations indicate that ADS-4 vent quality at the initiation of recirculation is about 50 percent and decreases to less than 10 percent at the time of wall-to-wall flooding. At the maximum vent quality, boron concentration is about 7400 ppm. The maximum boron solubility temperature is 14.4 °C (58 °F) (at 7400 ppm). The vessel is not expected to reach this temperature. Early in the LTC phase, with high decay heat, the high vent flow velocities can support an annular flow regime that moves water up and out the ADS-4 vent. In this case, a larger amount of water is expelled, creating a lower boron concentration in the core and a solubility temperature lower than 14.4 °C (58 °F). In summary, both physical considerations and calculation results indicate that the boron concentration in the core will not reach precipitation limits. The results of the AP1000 LTC phase are acceptable because boric acid precipitation in the core is precluded, preventing both criticality and/or flow blockage.

Operator Actions

The water level in the AP1000 sump varies from 33.3 m (109.3 ft)(from the plant reference elevation) at the beginning of recirculation for a non-DVI LOCA, to 31.5 m (103.5 ft) for a DVI LOCA and wall-to-wall flooding. Westinghouse stated that, during recirculation, the operators will be instructed to maintain the sump water level at or above the 32.6 m (107 ft) level. This practice adds a measure of assurance that adequate recirculation hydraulic head will exist during the LTC phase. Therefore, the core will remain covered with a two-phase mixture, and sufficient liquid entrainment will occur to ensure that boric acid is maintained well below precipitation limits.

Summary and Conclusion—LTC Boron Precipitation

Using WCOBRA/TRAC, Westinghouse analyzed the AP1000 LTC for the limiting case (i.e., highest decay heat level) DVI line break LOCA. Westinghouse also analyzed a variation of this case, which results in the lowest sump injection head through the broken DVI line (the wall-to-wall floodup case). The results show that sufficient ventflow (of medium- to low-quality steam) through the ADS-4 exists to remove enough water from the core to keep the boron concentration below 7400 ppm. The corresponding boron precipitation temperature is about 14.4 °C (58 °F), which is virtually unattainable in the vessel or the ADS-4 vent pipe. For the floodup case, the minimum sump injection head (through the broken DVI line) is adequate to maintain cooling and limit boron concentration. The applicant used an acceptable code to perform the analysis, and the results showed that the core boron concentration during LTC will not allow the core to become critical, nor will boron precipitation obstruct core coolant flow.

15.2.7.4 Additional Calculations

In Appendix H to WCAP-15644-P, Westinghouse provided additional analysis to (1) support the conclusion above regarding LTC boron precipitation and (2) to address a staff question regarding the instances with low decay heat that may not generate sufficient steam to support boron removal by expulsion of liquid through the ADS-4 valves. This section reviews this analysis.

The study consists of hand calculations and is based on a number of bounding assumptions. For the short term (as defined in Section 15.2.7.3 of this report), this study extends the size of the LOCA break to less than 5 cm (2 in.), with maximum makeup from the BAT. In such a case, the ADS may not actuate, and the plant would remain in this condition for some length of time. The hot-leg voids in about an hour, during which the CMT injects and increases the boron concentration. The BAT continues to inject borated water until it empties. Under those conditions, the maximum concentration is about 39,000 ppm, which could be reached in about 7 hours. In this case, the operator will likely be able to cool down and depressurize the RCS and avoid ADS actuation. The RCS temperature will remain well above the boron solubility temperature of about 87.8 °C (190 °F) (39,000 ppm) until the RNS cut-in temperature of 176.7 °C (350 °F) is reached. The RNS shutdown cooling operation would promote the RCS boron mixing. On the other hand, should the failure of the operator to shut the plant down actuate the ADS, injection from the IRWST will enter to dilute the boron concentration. In either case, the AP1000 emergency response guidelines (ERGs) require that the RCS be sampled for boron concentration to assure that sufficient shutdown margin exists and to prevent excessive concentration.

For the long term, after ADS-4 activation, boron concentration depends on the amount of water exiting from the ADS-4. A simplified model was developed, which considered the possibility of 100-percent quality steam through the ADS-4, or varying steam quality until the pressure drop through the system equals the driving injection head. In the first case, the hot water level will increase to the point where slugflow will be established. In the second case, the steam quality is sufficiently low so as to maintain an acceptable boron concentration. In addition, the method was used to estimate the capability of the core with reduced decay heat to expel water during LTC through the ADS-4. Such instances include (1) a very low core decay heat generation rate during the very long term and (2) the core decay heat immediately after refueling.

According to these results, with an initial core water level of 33.2 m (109 ft) and reasonable operator action to restore the sump level, the LTC phase can be maintained for a significantly long period of time (Westinghouse estimates this duration to be 6 years). Eventually, the decay heat cannot sustain steam velocity or quality to expel water. On the other end (i.e., a very short irradiation history, for which decay heat diminishes rapidly), a very small probability exists that a LOCA will occur during the time the reactor core has been operational. However, if a fresh core experiences a LOCA, the calculation indicates that the operator has adequate time to intervene and add water to restore the sump water level.

In summary, the auxiliary simplified calculations support the conclusions derived with WCOBRA/TRAC and extend the conclusion into low decay heat cases. The staff finds that emergency operating procedures and operator action can assure LTC for extended periods of time.

15.2.7.5 Closure of Open Item 15.2.7-1

In Revision 2 to the AP1000 DCD, the WCOBRA/TRAC LTC analysis was performed with the same noding as in the AP600 LTC analysis, which had only two axial nodes to represent the reactor core. However, the increased decay heat level and the increased core height to 4.3 m (14 ft) in the AP1000 design prompted the staff to request an analysis with a nodalization of sufficient detail to capture the spatial variation in the core void distribution. In the DSER, the staff identified Open Item 15.2.7-1, which stated that the applicant should provide more nodes in the vessel axial void distribution analysis during LTC to demonstrate that no possibility of core uncovery and adiabatic fuel heatup exists.

In the later revisions to the DCD, the applicant performed the LTC analysis, described in DCD Tier 2, Section 15.6.5.4C, based on a detailed nodalization model with 4 radial channels and 17 axial nodes to represent the reactor core. The LTC analysis results with this more detailed noding scheme were the subject of the preceding review and show that no long-term core uncovery occurred. The staff concludes that Open Item 15.1.7-1 is closed.

15.2.7.6 Staff Independent Post-LOCA Long-Term Cooling Calculation

This section describes the staff's independent calculation of the post-LOCA LTC behavior in the RCS to address the AP1000 system performance to maintain core cooling and preclude boron precipitation. During the LTC phase, the RCS will boil for extended periods of time, causing the boric acid concentration to increase in the vessel core and upper plenum regions.

Unlike conventional nuclear steam supply systems, the AP1000 does not rely primarily on operator action to control boric acid and prevent precipitation. Because of ADS-4 actuation, the AP1000 design ensures that boric acid is flushed from the core and RCS during the long term, because of the sustained entrainment of liquid from the upper plenum and hot-legs that is expelled through the ADS-4 piping to the containment. In order to evaluate LTC system performance, the staff developed several methodologies to show the inherent margin in the AP1000 that ensures a continued core cooling and flushing of the boric acid from the vessel during the post-LOCA LTC phase. The following discusses LTC behavior, models, and analytical results dealing with the prevention of boric acid precipitation in the AP1000.

LTC and the prevention of boric acid precipitation is addressed for all break sizes, including the double-ended DVI line break, which results in the earliest draintime for the IRWST and, hence, the earliest start of recirculation from the sump (i.e., 2.4 hours). Because this break results in the earliest start of recirculation, decay heat will be the highest, maximizing the pressure drop across the ADS-4 lines. Furthermore, because liquid must always be expelled out the ADS-4 lines to control boric acid, it is also necessary to show that the two-phase level remains above the centerline of the hot-leg. With the two-phase level above the centerline of the hot-leg, the steam will entrain liquid from the hot-leg piping and carry it out the ADS-4 lines as long as steaming rates are 6.8 kg/s (15 lb/s) or higher. Moreover, as the evaluation below demonstrates, once the steaming rate drops below 6.8 kg/s (15 lb/s), the pressure drop across the ADS-4 decreases so that the two-phase level rises to very near the top of the hot-leg. In this condition, a two-phase mixture is expected to spill from the RCS to the containment from the ADS-4 lines, continuing the removal of boric acid from the RCS. The steaming rate of

6.8 kg/s (15 lb/s) occurs after about 14 days following a reactor trip from full-power operating conditions, assuming no subcooling of the entering sump injection.

To show that liquid is expelled from the ADS-4 lines, a model will be described that demonstrates that the fluid levels in the vessel remain in the top half of the hot-leg.. This condition is necessary during the long term to assure that boric acid is flushed from the system. That is, it will also be shown that sufficient liquid is expelled to demonstrate that more liquid concentrate is removed than is accumulated in the core and upper plenum during extended boiling periods lasting for upwards of 14 days.

15.2.7.6.1 Long-Term Core Cooling Evaluation

To evaluate the AP1000 long-term core cooling behavior, the staff developed a T-H model, which consists of computing (1) the pressure drop from the upper plenum through the hot-legs and the ADS-4 lines to the containment when single phase steam exits the RCS (maximized pressure drop for a given mass flow rate), and (2) the hydrostatic differential head of water between the sump/downcomer and the inner vessel containing the core and upper plenum. The computation of this hydrostatic head differential assumes that the two-phase level in the vessel always remains at the centerline elevation of the hot-legs. This head differential is then compared to the pressure drop across the ADS-4 lines for a range of decay heat levels, down to and including conditions 14 days after initiation of the LOCA. Thus, if the pressure drop across the ADS-4 lines is less than or equal to the hydrostatic head differential between the sump/downcomer and inner vessel, then there is assurance that the two-phase level will always remain in the top half of the hot-leg, thereby assuring entrainment of liquid and the removal of boric acid from the system.

The staff evaluation made the following bounding assumptions:

- The containment pressure is 101.4 kPa (14.7 psia).
- The water in the sump and downcomer is saturated at 101.4 kPa (14.7 psia).
- The sump water level is at Elevation 31.4 m (103 ft) at the start of recirculation, which is the minimum level or elevation calculated by Westinghouse to be at Elevation 31.5 m (103'-5") at 14 days.
- Recirculation begins at 8640 seconds (0.104 days).
- Decay heat generation is based on the ANS-5.1-1971 standard increased by 20 percent

The staff used a drift-flux model to compute the void distribution in the core and upper plenum regions of the inner vessel. Appendix A to technical report, ISL-NSAD-NRC-01-003, "Preliminary Results of the AP1000 RELAP5/MOD3.3 Analysis for the Two-Inch Cold Leg and Main Steam Line Breaks," V. Palazov and L. Ward, Information Systems Laboratories, Inc., August 2001, describes this model in detail. This model was benchmarked against the thermal-hydraulic test facility (THTF) bundle uncovery tests and was validated against the ACHILLES low-pressure two-phase-level swell tests, as well as the THETIS boiloff tests, also performed at low pressure. The benchmarks showed that the drift-flux model predicted the void distribution (swelled level) within the experimental uncertainty for the tests.

To compute the pressure drop across the ADS-4 lines from the upper plenum at the two-phase surface, the staff developed an additional methodology. This model consisted of a simultaneous solution of the mass, energy, and momentum equations employing a volume-flowpath-network arrangement using a semi-implicit numerical scheme. The region from the upper plenum through each of the hot-legs and the ADS-4 lines was modeled as a series of parallel volumes and connecting flowpaths or junctions. The solution to the conservation equations produced a simultaneous solution of both the system pressure distribution and attendant mass flow rates. The equation for the time rate of change of pressure at each volume was derived from the definition of specific volume of the fluid, the energy equation, and the equation of state. The momentum equation contained the inertia term, the static pressure drop between cells, the geometric and friction pressure drop, and the recoverable momentum flux acceleration pressure losses. The time rate of change equations for pressure and momentum form a coupled set of differential equations. Westinghouse provided the geometric K-factors used to represent the piping and components from the upper plenum through the ADS-4 lines to the containment. The staff model increased the frictional pressure losses by 10 percent. In addition, the least-resistant ADS-4 line was conservatively assumed to fail closed.

The model was applied to the pressure drop data and sample problems in Crane ("Flow of Fluids Through Valves, Fittings, and Pipes," Crane Co., Technical Paper No. 14, 1988) and shown to reproduce the pressure drop for steam flowing in pipes with various geometric and frictional pressure losses. The model was also compared to the data of J.K. Ferrel, et al., (Ferrel, J.K., "Two-Phase Flow through Abrupt Expansions and Contractions," TID-23394 (Volume 3), North Carolina State University, June 1966) and predicted the pressure loss across contractions for a range of area ratios. Furthermore, this method was compared to a range of pressures and ADS-4 steam flow rates, and it was also shown to reproduce the pressure loss across the ADS-4 lines computed by Westinghouse using its detailed FLOAD4 network code.

Using the staff methodology described above, Figure 15.2.7.6 of this report compares the calculated hydrostatic head differentials between the sump/downcomer and inner vessel, covering the range of decay heat steaming rates from 25 kg/s to 5 kg/s (54.1 lb/s to 10.6 lb/s) (1.4 h to 14 days). The start of recirculation is 8640 seconds (2.4 h), with a steaming rate in the core of 21 kg/s (46.1 lb/s). Figure 15.2.7.6 of this report compares the head differential to the pressure drop across the ADS-4 lines over these decay heat generation rates. The two-phase level would be at the hot-leg centerline elevation only when the pressure loss across the ADS-4 lines equals the differential head of water between the sump/downcomer and inner vessel region. Clearly, when the ADS-4 pressure loss exceeds the differential head curve in Figure 15.2.7.6 of this report, the pressure loss across the ADS-4 lines is high enough to depress the two-phase level below the centerline of the hot-leg. In Figure 15.2.7.6 of this report, the vertical line indicates this condition so that, for steaming rates of about 23 kg/s (50 lb/s) and higher, the two-phase level will be depressed below the hot-leg centerline if only pure steam (quality = 1.0) should exit the system. The region to the right of the vertical line demonstrates that when only single vapor exits the ADS-4 lines, the pressure loss across the ADS-4 lines is insufficient to depress the two-phase level below the centerline of the hot-leg.

This demonstrates that the two-phase level would be higher than the prescribed two-phase level, which is always assumed to be at the hot-leg centerline. Because entrainment will remove liquid from the hot-legs for steaming rates above 7 kg/s (15 lb/s) (approximately 14 days after reactor trip), liquid is expelled from the RCS for 14 days following a LOCA. In fact, the difference between the upper and lower curve represents the excess margin in the AP1000 design and can be interpreted to mean that the two-phase level will remain near the top of the hot-leg from the earliest time for start of recirculation at 2.4 hours, through to decay heat levels producing steaming rates down to 7 kg/s (15 lb/s), or 14 days after reactor trip.

Furthermore, if the minimum sump level computed by Westinghouse based on conservative assumptions regarding containment performance is used, even more margin is available to guarantee the expulsion of liquid from the RCS. Bounding containment calculations by Westinghouse show that the sump level at 2.4 hours is at Elevation 32.9 m (108 ft) in the containment (higher than the assumed Elevation 31.4 m (103 ft) in the staff analysis). Using the sump level of 32.9 m (108 ft) at 2.4 hours which decreases to 32.6 m (107 ft) at 1 day, as shown in Figure 15.2.7.6 of this report, at the earliest time of recirculation (2.4 h), a margin of approximately 20.7-kPa (3-psi) in the pressure loss is required to depress the two-phase level below the hot-leg centerline. This water is also subcooled, but the Figure 15.2.7.6 analyses did not credit it. Subcooling would further increase the excess margin, as would higher containment pressures, because at 2.4 hours the minimum containment pressure is 131 kPa (19 psia). At these low pressures, an increase from the assumed 101.4 kPa (14.7 psia) containment pressure to the minimum justified pressure of 131 kPa (19 psia) would further reduce the pressure loss across the ADS-4 lines, since the pressure drop would decrease because of the lower steam specific volume at the higher pressures. Clearly, excess margin exists to cover uncertainty in the pressure losses in the ADS-4 lines (uncertainty in the CRANE resistances and unknown variations in the line resistance set up possibly by the interactions between two closely connected elbows or bends), as well as any additional uncertainty that may exist in the line resistances connecting the sump to the downcomer. Figure 15.2.7.6 of this report shows that, at the start of recirculation (2.4 h), a 20.7 kPa (3 psi) margin exists. This estimate is conservative because it did not credit subcooling and neglected the benefit of the higher containment pressure of 131 kPa (19 psia).

Lastly, this excess margin can also accommodate compressible effects. Crane shows that a compressible factor of 1/0.87 should be applied to the pressure drop when the hot-leg is at 137.9 kPa (20 psia), and the steam flow rate through one hot-leg is 13.61 kg/s (30 lb/s). The excessive margin shown in Figure 15.2.7.6 of this report more than sufficiently covers increases in the pressure drop from compressibility effects.

In view of these results, sufficient margin in the AP1000 design exists to assure that liquid will be expelled from the RCS through the ADS-4 lines for as long as 14 days following reactor trip. In fact, because of the excess margin displayed in Figure 15.2.7.6 of this report, two-phase fluid would be expected to spill from the RCS through the ADS-4 lines well beyond the 14-day period illustrated in this graph. Even as late as 14 days, ERGs will require the operators to take actions to secure the plant. These actions include raising the sump level to the elevation between 33.2 m (109 ft) and 33.5 m (110 ft) by filling the containment sump with subcooled water from the RNS. This action would ensure liquid expulsion from the RCS for an extended period of time and would ensure that the steaming rate in the core would be terminated because of the subcooling of the sump water and the very low decay heat generation beyond 14 days. Limiting the sump level to lower than 33.5 m (110 ft) will preclude submergence of the ADS-4 valves, thus preventing core uncovery.

15.2.7.6.2 Boric Acid Precipitation Evaluation

The AP1000 does not require operator action to mechanically flush the boric acid from the RCS. For larger and intermediate breaks, which result in the actuation of ADS-4, the RCS entrains and expels sufficient liquid to maintain the boric acid content well below precipitation limits. For very small breaks where the RCS pressure remains high for extended periods of time to prevent ADS-4 actuation, ERGs will require the operators to depressurize the RCS or refill the RCS with charging injection to disperse the boric acid throughout the primary system. The staff evaluates both situations with regard to the boron precipitation concerns, beginning with the large and intermediate break system response, followed by an assessment of the very small breaks.

Larger and Intermediate Breaks

To assess boric acid buildup, the staff developed a simple model to compute the boric acid accumulation in the vessel over time. The model describes the boric acid content in the core and upper plenum as a function of time with and without the flushing of boron via ADS-4 liquid entrainment.

Since the DEDVI line break produces the earliest IRWST draintime and, hence, the earliest start of sump recirculation, this break is the limiting event and is used to investigate the buildup of boric acid. The first staff calculation credits no core flushing or entrainment out the ADS-4 lines, so that a bounding calculation is performed to identify the earliest time to precipitation. In essence, the no-flushing calculation is independent of break size because boric acid buildup depends on decay heat. The result of the no-flushing assumption shows that boron precipitation could occur about 5 hours into the event.

The second calculation assumes flushing through ADS-4 liquid entrainment. This analysis includes the following bounding assumptions:

- The decay heat generation is increased by 20 percent.
- The mixing volume is based only on the core region.
- The BAT injects at the maximum rate of 662.45 L/min (175 gpm).
- The concentration of the BAT is 2.4 percent.
- No entrainment or flushing is credited before IRWST drainage.
- At the start of recirculation, only a 2.27 kg/s (5 lb/s) flushing flow is assumed (flow in excess of the core boiloff rate).

The calculation credits ADS-4 liquid entrainment at the initiation of sump recirculation, which occurs 2.4 hours into the event. At 2.4 hours or the start of recirculation, a flushing flow out the ADS-4 lines of only 2.27 kg/s (5 lb/s) is assumed, which is the flow in excess of the decay heat steaming rate of about 20.87 kg/s (46 lb/s). The 2.27-kg/s (5-lb/s) liquid flow out of ADS-4 valves is a very conservative bounding assumption, as the RELAP5 calculations of the DEDVI line break show that the liquid flow out of the ADS-4 during the ADS-4 blowdown period and LTC period well exceeds 23.13 kg/s (51 lb/s). The calculation used containment pressures, sump levels, and sump temperatures from the bounding LTC analysis provided by Westinghouse as boundary conditions for the determination of the liquid flow out the ADS-4 lines.

With this bounding assumption, the calculated boric acid concentration in the core over time shows that at the start of recirculation, the excess flushing flow of 2.27 kg/s (5 lb/s) is sufficient to reduce the boric acid concentration in the vessel. Furthermore, during the blowdown or before IRWST injection, ADS-4 actuation would produce a liquid flow out the valves in excess of the boiloff, which would act to reduce the boric acid concentration much earlier in this event. Even with no credit for entrainment during blowdown, for conservatism, the boric acid concentration does not reach the precipitation limit of 32 wt% (corresponding to the saturation temperature at the minimum containment pressure of 137.9 kPa (20 psia) at the start of recirculation). This calculation produces a higher boric acid concentration than that calculated by Westinghouse. Calculations taking credit for a minimal flushing flow of 2.27 kg/s (5 lb/s) when the ADS-4 valves first open during blowdown (i.e., about 2000 seconds) show that the maximum concentration is 15.8 wt% (27,538 ppm), achieved shortly after the start of recirculation. This result assumes saturated inlet conditions to maximize the boiloff rate and the rate at which boron builds up in the core. When subcooling is credited at 48.9 °C (120 °F), the concentration remains well below the 27,538 ppm concentration because of the decreased boiloff rate in the core.

Based on this bounding analysis, the staff concludes that the boric acid concentration will not reach precipitation limits following breaks in the RCS that produce ADS-4 actuation.

Very Small Breaks

In the event of a very small break with a diameter of 1.3 cm (0.5 in.) or less, the RCS could boil for extended periods of time while remaining at elevated pressures and conditions, which would delay actuation of the ADS-4 valves. Under these conditions, injection from the CMTs, accumulators, and BAT could increase the boric acid concentration in the vessel. Since the break is small with RCS pressures remaining high, the CMTs do not rapidly drain, delaying the ADS-4 valve actuation. If boiling persists for several hours, concentrations could increase to values that, although soluble at the high pressures and temperatures, could cause precipitation should ADS-4 eventually actuate and rapidly depressurize the RCS. To investigate the time to reach precipitation limits corresponding to RCS pressures at 137.9 kPa (20 psia), the staff performed an analysis to determine the time required to increase the boric acid content in the core to 32 wt%. Assuming the BAT injects with the boric acid content of 2.4 percent, about 3.5 hours of boiling would be sufficient to increase the boric acid content in the core to 32 wt%. This assumption is considered to be bounding because the staff assumed saturated inlet conditions and did not credit the fact that, as subcooled water enters the core, the boiloff rate and the rate at which boric acid builds up in the core are significantly reduced.

As documented by Westinghouse, ERGs will instruct the operators to sample RCS boric acid content and take actions to reduce the concentration of the injected boric acid or initiate an early cooldown to prevent boric acid precipitation, in anticipation of ADS-4 actuation after extended periods of boiling. The ERGs assure that precipitation limits are never exceeded following very small breaks in the RCS. Such actions to control boric acid for the very small breaks are directed after 1 hour, but no later than 3 hours.

15.2.8 Deboration during SBLOCAs

The staff reviewed the issue of boron dilution associated with the SBLOCA reflux condensation, the so-called "Finnish scenario." In response to RAI 440.099, Revision 1, the applicant provided its evaluation, which concluded that the Finnish scenario is of no consequence to the AP1000 reactor design because the AP1000 does not rely on SGs to cool the RCS during an SBLOCA event. Consequently, the SGs should not generate any significant amount of conservatively assumed boron-free condensate via reflux condensation over an extended period of time during an SBLOCA event. The following describes the staff evaluation in detail.

During an SBLOCA, the SG functions as a heat source as the RCS depressurizes, rather than a heat sink. Therefore, the differential temperature across the primary and secondary side of the generators is such that steam from the reactor will not condense on the tubes.

The AP1000 PRHR HX becomes a dominant RCS heat sink following the generation of an "S" signal during a postulated SBLOCA event. As such, the PRHR HX could become a potential source for generating a volume of unborated coolant during an SBLOCA. Such a scenario could lead to a reactivity excursion as a result of a restart of an RCP after the unborated water slug had collected in the reactor coolant loop. The applicant had determined that this scenario is not a concern for the AP1000 design for the following reasons. Specifically, the AP1000 reactor coolant loop piping does not contain a loop seal, and thus no point exists to collect a large slug of unborated condensate in the reactor coolant loop piping. During the SBLOCA event, once subcooling in the RCS is lost, steam will enter the PRHR HX and will condense on the inside of the PRHR HX tubes. Steam condensed in the PRHR is delivered to the Loop 1 SG outlet plenum. The AP1000 loop layout does not contain an RCP crossover leg, and the PRHR condensate will drain continuously from the SG channel head into the Loop 1 cold-legs and flow into the RV.

During the SBLOCA transient, the water in the cold-legs enters the downcomer, where it mixes with the highly borated safety injection flow from either the accumulators, the CMTs, or both. The relatively low flow rate of fluid from the downcomer into the core, during the post-RCP-trip natural circulation phase of the AP1000 SBLOCA events, enables mixing to occur in the downcomer and lower plenum. No unmixed slugs of unborated water from the PRHR can form in the downcomer and enter the core during this scenario.

The applicant performed bounding calculations that demonstrated that it was not credible to postulate that the boron concentration in the downcomer and lower plenum would be diluted to a critical boron concentration for this postulated LOCA. The conclusions from these studies, which show that boron dilution from the operation of the PRHR HX would not occur, were based on demonstrating that the PRHR condensate would adequately mix with the water in the downcomer and the lower plenum so that a critical boron concentration would not be reached.

The AP1000 uses a low boron core design with the boron concentration at the BOC of approximately 1000 ppm. The low AP1000 core boron concentration significantly reduces the potential for the PRHR to dilute the coolant in the RV to the point of criticality. Although the AP1000 PRHR flow rate is high, the CMT flow rate, the RV downcomer, and the lower plenum volume for the AP1000 are also high. Taking these differences into account, the AP1000 design studies show that post-LOCA boron dilution is not a concern, provided that good mixing exists in the vessel. Analysis for the AP1000 showed that mixing in the RV downcomer and lower plenum will counteract boron dilution in the core from PRHR operation.

NUREG/IA-0004, "Thermal Mixing Tests in a Semiannular Downcomer with Interacting Flows from Cold Legs," issued October 1986, reported the study of the mixing of high-pressure safety injection water with primary coolant in a simulated PWR downcomer. Test #106 in NUREG/IA-0004 considers a geometry which represents the PRHR condensate delivery geometry into the AP1000 downcomer, namely equal flow rates of liquid entering the downcomer through two cold-legs which are 90 degrees apart at the connection into the RV vessel. The downcomer at the test facility is shorter in length (approximately 3.08 m (10 ft)) than the AP1000 dimension (approximately 6.16 m (20 ft) from the cold-leg bottom to the bottom of the downcomer). The test facility, therefore, provides less than one-half of the mixing length available in the AP1000 downcomer. The fluid velocity in the test facility cold-legs is approximately 0.14 m/s (0.45 ft/s) for the simulated high-pressure injection (HPI) flow injection in Test #106, as indicated by the "C" series of figures in NUREG/IA-0004. This is similar to the velocity of the PRHR condensate in the cold-legs for SBLOCA scenarios. Therefore, the parameters of Test #106 are such that the observed results provide meaningful insights into the mixing that occurs in the AP1000 downcomer during the SBLOCA boron dilution scenarios. The results of Test #106 illustrate that the injected plume thoroughly mixes with the resident downcomer liquid during the 3.08-m (10-ft) fall to the bottom elevation. The Test #113 results in NUREG/IA-0004 provide further support for AP1000 downcomer mixing.

Test #113 was run at a simulated HPI rate that is 3.6 times greater than that of Test #106, with a 60 degree angle between the two cold-leg injection connections, as depicted in the "D" series of photographs in NUREG/IA-0004. Test #113 results show mixing behavior in the downcomer which closely resembles that of Test #106. Test #113 indicates that the sensitivity of downcomer mixing to initial plume velocity is minor. These two tests provide compelling evidence that the diluted boron stream in the AP1000 PRHR condensate delivery scenarios is well mixed in the downcomer and that no unmixed slugs enter the lower plenum or core. These test results provide additional independent technical justification that the degree of mixing which occurs in the AP1000 downcomer during the PRHR condensate return scenarios is more than adequate to disperse a plume of diluted boron liquid. The test results support the conclusion that recriticality of the core is not of concern for SBLOCA scenarios.

Based on the information provided in the submittal of the AP1000 DCD, and on the analysis performed by Westinghouse on behalf of this event, including the thermal tests mentioned in NUREG/1A-0004, the staff finds that the analysis in support of the possible deboration from an SBLOCA event is acceptable.

15.2.9 Anticipated Transients Without Scram (DCD Tier 2, Section 15.8)

An ATWS event is defined as an AOO (such as LONF, loss of condenser vacuum, or LOOP) combined with an assumed failure of the RTS to shut down the reactor. On June 26, 1984, the Commission amended the Code of Federal Regulations to include 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants" (known as the ATWS Rule). This rule, as amended on July 6, 1984; November 6, 1986; April 3, 1989; and July 29, 1996, requires nuclear power plant facilities to reduce the likelihood of failure to shut down the reactor following anticipated transients and to mitigate the consequences of ATWS events.

The equipment to be installed in accordance with the ATWS Rule must be diverse from the existing RTS and must be capable of testing at power. This equipment will provide needed diversity to reduce the potential for common-mode failures that result in an ATWS and lead to unacceptable plant conditions.

For the PWRs manufactured by Westinghouse, 10 CFR 50.62(c)(1) specifies the basic requirements of the ATWS Rule:

> Each pressurized water reactor must have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater and initiate a turbine trip under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner and be independent (from sensor output to the final actuation device) from the existing reactor trip system.

The AP1000 design includes a control-grade diverse actuation system (DAS) to provide an alternate turbine trip signal and an alternate actuation signal of the PRHR system for decay heat removal, which are separate and diverse from the safety-grade RTS and PRHR normal actuation signals. The DAS also provides a diverse scram function. Section 7.7 of this report discusses the staff's review and acceptance of the applicant's DAS design.

The AP1000 design relies on the PRHR in lieu of an auxiliary or emergency feedwater system as its safety-related method for removing decay heat. In its letter, "AP1000 Request for Exemption," DCP/NRC-1534, dated December 3, 2002, the applicant submitted a request for exemption from the part of the ATWS Rule, 10 CFR 50.62(c)(1), that requires auxiliary or emergency feedwater as an alternate system for decay heat removal during an ATWS event. The staff concludes that the applicant has met the intent of the ATWS Rule by relying on the PRHR system to remove the decay heat and meets the underlying purpose of the rule. Therefore, the Commission has determined that the special circumstances described in 10 CFR 50.12(a)(2)(ii) exist, in that the requirement for an auxiliary or emergency feedwater system is not necessary to achieve the underlying purpose of 10 CFR 50.62(c)(1), because the applicant adopted acceptable alternatives that accomplish the intent of this regulation, and the exemption is authorized by law, will not present an undue risk to public health and safety, and is consistent with the common defense and security.

The applicant provided the results of an ATWS analysis in AP1000 Probabilistic Risk Assessment, Appendix A, Section A4, for the staff to review. In its analysis, the applicant used a complete LONF event as an initial event for the ATWS analysis because the LONF event was previously established as the limiting case (i.e., produced the maximum RCS pressure) for the AP600.

The applicant performed the ATWS analysis with the LOFTRAN code. The AP1000 DAS is credited to function in the analysis for ATWS cases. Specifically, the DAS is credited to actuate a turbine trip and the PRHR when the low wide-range SG-level signal is generated. Two LONF cases are analyzed, one for equilibrium cycle core (ECC) conditions and one for first cycle core (FCC) conditions. The ECC case used an MTC of -12.5 pcm/°F, which is the least negative MTC at any time in an ECC condition. The analysis shows that the peak RCS pressure is about 20.68 MPa (3000 psia), which is less than the limit of 22.06 MPa (3200 psia). For the FCC case, the LONF analysis shows that with an MTC of -10 pcm/°F, the calculated peak RCS reaches about 22.06 MPa (3200 psia). The MTC used in the analysis for the FCC case is less than 60 percent of the cycle time. Therefore, the unfavorable exposure time (UET) for the FCC case is 40 percent. The UET is the time during the fuel cycle when the reactivity feedback is not sufficient to maintain pressure under 22.06 MPa (3200 psia) for a given reactor state. The staff requested, in a followup question to RAI 440.014, that the applicant provide additional justification to show that the LONF analysis is the worst case, and the selection of the MTC used in the analysis is acceptable with respect to the acceptable UET limit.

In response, the applicant performed a probabilistic risk assessment (PRA) evaluation to identify the frequency of the anticipated transients in DCD Tier 2, Chapter 15, and specify the most risk-significant ATWS scenarios for the AP1000 design. Based on the results of the PRA evaluation, the applicant identified the most risk-significant ATWS scenarios which make up more than 95 percent of the AP1000 ATWS initiating event frequency. The applicant performed ATWS analyses on the most risk-significant ATWS cases that, based on the results of the DCD Tier 2, Chapter 15, non-LOCA analysis for the AP1000, may result in a significant pressure increase during the transients. The applicant analyzed the following cases in detail to identify the scenario that results in the least margin to the RCPB limit for the AP1000:

- turbine trip without feedwater system operable with turbine bypass system operable
- turbine trip with feedwater system operable with turbine bypass system operable
- turbine trip without feedwater system operable without turbine bypass system operable
- LONF event with turbine bypass system operable
- LONF event without spray system, without turbine bypass system operable
- LONF event with turbine bypass system operable, more realistic SG heat transfer model
- complete loss of forced coolant flow with main feedwater system (MFWS) operable with turbine bypass system operable

- complete loss of forced coolant flow with MFWS operable without turbine bypass system operable

- complete loss of forced coolant flow induced by the loss of ac power, MFWS not operable, no steam dump operable, turbine trip at the initiation of the transient

The results of the ATWS analysis for the above cases confirm that, for the AP1000 design, the limiting case is the LONF event with the turbine bypass operable, resulting in the highest peak RCS pressure.

In addressing the second concern in RAI 440.014, related to the acceptability of the MTC value used in the ATWS analysis for the limiting case, the applicant has revised the DAS actuation logic to improve its capability for accident mitigation in response to an ATWS event. In addition to actuation of the PRHR and the turbine trip, the new logic actuates the CMT and RCP trip on the low wide-range SG-level signal. Together with implementation of a new DAS logic, an additional change has been implemented in the PLS, such that the PLS isolates the steam dump system whenever the SG level drops below the low wide-range SG water-level setpoint. DCD Tier 2, Section 7.1.1, includes the description of the new DAS logic.

Section 7.7.1 of this report discusses the review and acceptance of the new logic. The applicant performed an ATWS analysis of the LONF event for the AP1000, with the new DAS ATWS protection logic assuming an MTC of -5 pcm/°F. The value of the MTC envelops 100 percent of the AP1000 core life. The results of the ATWS show that for the limiting case, the LONF event, the maximum calculated RCS pressure is 19.43 MPa (2818 psia), which is within the acceptance limit of 22.06 MPa (3200 psia). The limiting ATWS case demonstrates that the UET (i.e., the time during the fuel cycle when the reactivity feedback is not sufficient to maintain pressure under 22.06 MPa (3200 psia) for a given reactor state) does not exist for the AP1000 design. RAI 440.014, Revision 1, and AP1000 Probabilistic Risk Assessment, Appendix A, Section A4, include the information on the new ATWS analysis discussed in this section. Because (1) the ATWS analysis used the LOFTRAN code previously approved by the NRC, (2) the limiting ATWS case is identified based on the results of the actual ATWS analysis discussed in this section, (3) the value of the MTC used in the limiting case analysis envelops 100 percent of the AP1000 fuel cycles, and (4) the calculated peak RCS pressure for the limiting case falls within the pressure limit acceptance criterion, the staff concludes that the ATWS analysis is acceptable.

15.2.10 Conclusions

The staff has reviewed the safety analyses of the design-basis transients and accidents described DCD Tier 2, Chapter 15, for the AP1000 design. Based on the evaluation discussed above, the staff concludes that the AP1000 design meets the acceptance criteria for these transients and accidents.

As discussed in Section 15.2.9 of this report, the staff concludes that the applicant's request for exemption to the ATWS Rule of 10 CFR 50.62 is acceptable. Specifically, the exemption request applies to 10 CFR 50.62(c)(1), which requires auxiliary or emergency feedwater as an alternate system for decay heat removal during an ATWS event. The AP1000 design relies on the PRHR in lieu of an auxiliary or emergency feedwater system as its safety-related method of removing decay heat. The staff concludes that the AP1000 design meets the underlying purpose of the ATWS Rule by relying on the PRHR system to remove the decay heat. In accordance with 10 CFR 50.12(a)(2)(ii) for the AP1000 design, the requirement for an emergency feedwater system is not necessary to achieve the underlying purpose of 10 CFR 50.62(c)(1). Therefore, the exemption request is acceptable.

15.3 Radiological Consequences of Accidents

In DCD Tier 2, Chapter 15, the applicant performed radiological consequence assessments of the following seven reactor design-basis accidents (DBAs), using the hypothetical set of atmospheric relative concentration (dispersion) values (χ/Q values) provided in DCD Tier 2, Table 15A-5. Because all other aspects of the design are fixed, these χ/Q values help determine the required minimum distances to the exclusion area boundary (EAB) and the low-population zone (LPZ) for a given site in order to provide reasonable assurance that the radiological consequences of a DBA will be within the dose limits specified in 10 CFR 50.34(a)(1)(ii)(D). The analyzed DBAs include the following:

- MSLB outside containment (DCD Tier 2, Section 15.1.5)
- RCP shaft seizure (locked rotor) (DCD Tier 2, Section 15.3.3)
- RCCA ejection (DCD Tier 2, Section 15.4.8)
- failure of small lines carrying primary coolant outside containment (DCD Tier 2, Section 15.6.2)
- SGTR (DCD Tier 2, Section 15.6.3)
- LOCA (DCD Tier 2, Section 15.6.5)
- fuel-handling accident (FHA) (DCD Tier 2, Section 15.7.4)

In DCD Tier 2, Chapter 15, the applicant concluded that the AP1000 design will provide reasonable assurance that the radiological consequences resulting from any of the above DBAs will fall within the offsite dose criterion of 0.25 Sv (25 rem) total effective dose equivalent (TEDE), as specified in 10 CFR 50.34(a)(1)(ii)(D), and the control room operator dose criterion of 0.05 Sv (5 rem), as specified in GDC 19, "Control Room," of Appendix A to 10 CFR Part 50. The applicant reached this conclusion by performing the following:

- using reactor accident source terms based on NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants," and RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors"
- relying on natural deposition of fission-product aerosol within the containment

- controlling the pH of the water in the containment to prevent iodine evolution
- using a set of hypothetical atmospheric dispersion factor (χ/Q) values

The χ/Q values are the relative atmospheric concentrations of radiological releases at the receptor point in terms of the rate of radioactivity release. In lieu of site-specific meteorological data, the applicant provided a reference set of χ/Q values for the AP1000 design using meteorological data that is expected to bound 70 to 80 percent of U.S. operating nuclear power plant sites for offsite dispersion. In DCD Tier 2, Tables 2-1 and 15A-5 list the AP1000 hypothetical χ/Q values, and DCD Tier 2, Table 15A-6, lists the AP1000 hypothetical χ/Q values for the control room.

Regulatory Evaluation

The staff evaluated the radiological consequences of DBAs against the dose criteria, specified in 10 CFR 50.34(a)(1)(ii)(D), of 0.25 Sv (25 rem) TEDE at the EAB for any 2-hour period, following the onset of the postulated fission product release, and 0.25 Sv (25 rem) TEDE at the outer boundary of the LPZ for the duration of exposure to the release cloud. The staff used a criterion of 0.05 Sv (5 rem) TEDE for evaluating the radiological consequences from DBAs in the control room of the AP1000 design, pursuant to GDC 19 of Appendix A to 10 CFR Part 50. The staff used applicable guidance in SRP Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," and RG 1.183 in its review of the AP1000 DBA radiological consequence analyses. RG 1.183 provides guidance on radiological consequence analyses to those licensees of operating power reactors choosing to implement an alternative source term pursuant to 10 CFR 50.67, which has the same regulatory dose criteria as those specified in 10 CFR 50.34(a)(1)(ii)(D) (i.e., 0.25 Sv (25 rem) TEDE) and GDC 19 (i.e., 0.05 Sv (5 rem) TEDE). Although RG 1.183 applies to the current operating power reactors, its guidance on radiological acceptance criteria, formulation of the source term, and DBA modeling is useful in the review of the AP1000 design because the AP1000 is an advanced PWR.

Technical Evaluation

The staff reviewed the radiological consequence analyses performed by Westinghouse using the hypothetical χ/Q values given in DCD Tier 2, Tables 15A-5 and 15A-6. The staff finds that the radiological consequences calculated by Westinghouse meet the relevant dose acceptance criteria stated above. To verify the Westinghouse analyses, the staff performed independent radiological calculations for the above DBAs using the hypothetical χ/Q values provided by the applicant and the computer code described in Supplement 2 to NUREG/CR-6604, "RADTRAD: A Simplified Model for Radionuclide Transport and Removal and Dose Estimation." The following sections describe the staff's findings.

Accident Source Terms

In SECY-94-302, "Source Term-Related Technical and Licensing Issues Relating to Evolutionary and Passive Light-Water-Reactor Designs," dated December 19, 1994, the staff proposed to use only the coolant, gap, and early in-vessel releases from NUREG-1465 for the radiological consequence assessments of DBAs for the passive advanced light-water reactor

(ALWR) designs. These source terms encompass a broad range of accident scenarios, including significant levels of core damage with the core remaining in the vessel. These scenarios define the most severe accidents from which the plant could be expected to return to a safe-shutdown condition. The revised source terms in NUREG-1465 must be applied conservatively in evaluating DBAs in conjunction with conservative assumptions in calculating doses, such as adverse meteorology. Application to severe accidents may use more realistic assumptions.

The staff considered the inclusion of the ex-vessel and the late in-vessel source terms to be unduly conservative for DBA purposes. Such releases would only result from core damage accidents with vessel failure and core-concrete interactions. For passive ALWRs, the estimated frequencies of such scenarios are low enough that they do not have to be considered credible for the purpose of meeting 10 CFR 50.34. In SECY-94-302, the Commission approved the staff-recommended technical positions to use only the coolant, gap, and early in-vessel releases from NUREG-1465 for the radiological consequence assessments of DBAs for the passive ALWR designs.

The NRC issued RG 1.183 in July 2000 to provide guidance to licensees of operating power reactors on acceptable applications of alternative source terms pursuant to 10 CFR 50.67. This RG provides guidance based on insights from NUREG-1465 and significant attributes of other alternative source terms that the NRC staff may find acceptable for operating light-water reactors (LWRs). It also identifies acceptable radiological analysis assumptions for use in conjunction with the accepted alternative source term for operating power reactors. The applicant followed the relevant guidance in RG 1.183 for PWRs.

Post-Accident Containment Water Chemistry Management

Management of the postaccident containment water chemistry must comply with the requirements of GDC 41, "Containment Atmosphere Cleanup," and GDC 4, "Environmental and Dynamic Effect Design Bases." By minimizing the release of radioactive iodine from the containment sump water, the water chemistry will meet the requirement of GDC 41, as it relates to the ability of the design of containment atmosphere cleanup systems to control fission product releases to the reactor containment following postulated accidents. By preventing stress-corrosion cracking of stainless steel components exposed to the water accumulated in the containment sump, the water chemistry will meet the requirement of GDC 4 that components important to safety be compatible with the environmental conditions associated with accident conditions, including LOCAs.

NUREG-1465 states that, after an accident, iodine entering the containment from the reactor core is composed of at least 95 percent cesium iodide (CsI), with the remaining 5 percent elemental iodine and a small amount of hydriodic acid. However, about three percent of elemental iodine in contact with some organic compounds will produce organic iodides. Therefore, the iodine in the containment will consist of 95 percent particulate iodine as CsI, 4.85 percent elemental iodine (I_2), and 0.15 percent organic iodine. The composition of the iodine in the AP1000 is consistent with the composition stated in NUREG-1465.

Iodine in the form of CsI is soluble in the containment water. However, some of it may be converted into the elemental form, which is considerably less soluble, and will be released into the containment atmosphere. The released radioactive iodine may leak out of the containment and contribute to outside radiation doses. To minimize formation of the elemental iodine, the pH of the containment water should be kept basic. Basic pH will also prevent stress-corrosion cracking of the stainless steel components.

In the AP1000, the pH of the containment water will be between 7 and 9.5, which is the range found acceptable in Branch Technical Position (BTP) Materials Engineering Branch (MTEB) 6-1 of the SRP. A predetermined amount of trisodium phosphate (TSP) stored in the stainless steel baskets situated on the containment floor will maintain the pH in this range. After a LOCA, when the containment flooding water reaches the level of the baskets, the TSP will dissolve, and the solution of TSP will exercise buffering action and maintain sump water pH in the required range.

Acidic and basic chemical species released to the containment from different sources in the plant determine the pH of the containment sump water. Boric acid produces the most significant effect on reducing containment water pH. Westinghouse identified the RCS, IRWST, CMTs, accumulators, CVCS BAT, and spent fuel pool cooling system (SFS) cask loading pit as sources of boric acid. Westinghouse did not include normal operating RCS leakage, because in the AP1000 plant design such leakage would quickly drain to the waste sump and be pumped out of the containment. Other sources of chemical species that are formed in the containment during the 30 days following a core damage accident include hydrochloric acid produced by radiolytic decomposition of electric cable jackets and nitric acid produced by radiolytic formation from air dissolved in the sump water. In addition, there is cesium hydroxide present, released from the damaged core. Because it is a strong base, cesium hydroxide will contribute to the increase of the pH. The applicant has determined that the baskets in the containment sump must store 12,492 kg (27,540 lb) of TSP to maintain the pH in the range of 7 to 9.5. While 7,503 kg (16,540 lb) of TSP is needed to neutralize boric acid, the rest will neutralize other acids existing in the containment and provide a 35-percent safety margin, which includes 10 percent to cover possible long-term degradation of TSP.

By performing independent verifications, based on the information provided in the response to RAI 281.004, the staff has confirmed the adequacy of the postaccident management of water chemistry in the AP1000 plant design. The staff finds that the amount of TSP stored in the containment sump will ensure a basic environment that will minimize the release of radioactive iodine to the outside and will prevent stress-corrosion cracking of the stainless steel components exposed to the containment water. The staff concludes, therefore, that the AP1000 plant design meets the requirements of GDC 41 and 4.

<u>Hypothetical Atmospheric Dispersion Factors</u>

Because no specific site is associated with the AP1000 plant, Westinghouse defined the offsite boundaries only in terms of various hypothetical atmospheric relative concentration (χ/Q) values at fixed EAB and LPZ distances. DCD Tier 2, Tables 15A-5 and 15A-6 list the hypothetical reference χ/Q values used in the radiological consequence analyses for the AP1000 design. Section 2.3.4 of this report provides the staff's discussion of the hypothetical atmospheric dispersion factors. The staff will perform an independent assessment of short-term (less than or equal to 30 days) atmospheric dispersion factors for potential accident consequence analyses on a site-specific basis for a COL application that references the AP1000 design. If site-specific atmospheric dispersion factors exceed the reference values used in this evaluation (e.g., poorer dispersion characteristics), a COL applicant may have to consider compensatory measures, such as increasing the size of the site or providing additional ESF systems to meet the relevant dose limits set forth in 10 CFR 50.34 and GDC 19.

The staff had not completed its review of the control room atmospheric dispersion factors at the time the DSER was issued. Because the radiological consequence analyses for control room habitability use the control room atmospheric dispersion factors as an input, the staff could not make a finding on the acceptability of the Westinghouse analyses. In addition, the staff could not make a finding on whether Westinghouse had shown that the AP1000 design would be expected to meet GDC 19 for the hypothetical meteorological conditions used in the DCD. With the conclusion of the staff's review of the control room atmospheric dispersion factors, discussed in Section 2.3.4 of this report, the staff has completed its review of the control room habitability radiological consequences analyses. Therefore, DSER Open Item 15.3-2 is closed.

15.3.1 Radiological Consequences of a Main Steam Line Break Outside Containment

Both the staff and Westinghouse have evaluated the radiological consequences of a postulated SLB accident occurring outside of the containment and upstream of the MSIVs. The applicant submitted a radiological analysis for the MSLB accident in DCD Tier 2, Section 15.1.5.4. The applicant analyzed this hypothetical accident using the following parameters:

- 567.8 L/d (150 gal/d) of primary-to-secondary leakage through any one SG, as specified in the AP1000 TS
- discharge of the entire mass of secondary water from one affected SG to the environment with no iodine partitioning

The applicant also considered a coincident loss of spent fuel pool (SFP) cooling capability. Section 15.3.9 of this report discusses the staff's review of the radiological consequences of SFP boiling.

The staff has reviewed the applicant's analysis and finds that the calculational methods used for the radiological consequence assessment are acceptable, and the radiological consequences calculated by the applicant meet the relevant dose acceptance criteria.

To verify the applicant's assessment, the staff performed an independent radiological consequence calculation for three scenarios for the MSLB accident. For Case 1, the most reactive control rod was assumed to be stuck in the fully withdrawn position. The applicant indicated, and the staff agreed, that no DNB is expected to occur. Therefore, the calculation did not assume fuel-cladding failure. With no additional fuel failures occurring, Case 1 becomes identical to Case 2 (discussed below), and no radiological consequences are presented for Case 1.

For Case 2, the staff assumed that a temporary increase in the primary coolant iodine concentration (iodine spike) occurred as a result of the power/pressure transient caused by the MSLB accident. Before the accident, the AP1000 reactor was assumed to operate at the AP1000 TS equilibrium limit of 37 kBq/gm (1.0 μCi/gm) for dose equivalent iodine-131 (DEI-131) in the primary coolant. The iodine spike generated during the accident is assumed to increase the release rate of iodine from the fuel by a factor of 500. This increase in the release rate results in an increasing concentration in the primary coolant during the course of the accident. For Case 3, the staff assumed that previous reactor operation had resulted in a primary coolant iodine concentration equal to the maximum instantaneous AP1000 TS limit of 2.2 MBq/gm (60 μCi/gm) for DEI-131.

Tables 15.3-2 and 15.3-1 of this report provide the major parameters and assumptions used by the staff for the MSLB accident and the results of the staff's radiological consequence analyses for the EAB, LPZ, and control room, respectively. The offsite radiological consequences calculated by the staff are consistent with those calculated by the applicant.

The staff concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated MSLB accident with accident-induced iodine spiking and coincident with the loss of SFP cooling capability will not exceed a small fraction (i.e., 10 percent or 0.025 Sv (2.5 rem) TEDE) of the dose criterion set forth in 10 CFR 50.34.

The staff also concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated MSLB accident with the reactor coolant at the TS maximum value of 2.2 MBq/gm (60 μCi/gm) for DEI-131 and coincident with the loss of SFP cooling capability will not exceed the dose criterion set forth in 10 CFR 50.34 (i.e., 0.25 Sv (25 rem) TEDE).

In DCD Tier 2, Section 6.4.4, Westinghouse reported the results of its radiological consequence analysis for personnel in the main control room during a design-basis MSLB, relying on the main control room emergency habitability system (VES) to limit the radioactivity to which the personnel may be exposed. Section 6.4 of this report describes the staff's review and assessment of the VES. To verify the Westinghouse assessment, the staff performed an independent radiological consequence calculation for the MSLB accident with VES operation under high-high radiation levels. The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following a design-basis MSLB to meet the dose criterion specified in GDC 19. Tables 15.3-9 and 15.3-1 of this report provide the major assumptions used by the staff and the resulting radiological consequence analysis results for the control room operators, respectively.

The calculation of the dose to the control room operators does not rely on the nuclear island nonradioactive ventilation system (VBS), a non-safety-related system, to meet the requirements of GDC 19. Under some accident circumstances, the non-safety-related VBS would be available to pressurize the control room and the technical support center (TSC) with filtered air and to provide recirculation cleanup. Section 9.4 of this report describes the staff's review and assessment of the non-safety-related VBS. In DCD Tier 2, Section 6.4.4, Westinghouse also reported the results of its radiological consequence analysis for personnel in the main control room and the TSC during a design-basis MSLB with the VBS available. The staff finds reasonable the Westinghouse assertion that, if available, the VBS can mitigate the dose in the main control room and the TSC following a design-basis MSLB to be within 0.05 Sv (5 rem) TEDE. Table 15.3-9 of this report provides the major assumptions used by the staff and the resulting radiological consequence analysis results for the personnel in the control room and the TSC with VBS available.

15.3.2 Radiological Consequences of a Reactor Primary Coolant Pump Seizure (Locked Rotor)

An instantaneous seizure of an RCP rotor rapidly reducing the primary coolant flow through the affected reactor coolant loop, leading to a reactor trip on a low-flow signal, causes the reactor primary coolant pump seizure accident. Westinghouse analyzed this hypothetical accident assuming that 10 percent of the fuel elements will experience cladding failure, releasing the entire fission product inventory in the fuel-cladding gap of these elements to the reactor coolant. The maximum allowable 1135.6 L/d (300 gal/d) of primary-to-secondary leakage through two SGs, as specified in the AP1000 TS, carries the activity released to the primary coolant into the secondary coolant. The steamline safety valves or the PORVs release the activity to the environment. The applicant submitted a radiological analysis for the reactor primary coolant pump seizure accident in DCD Tier 2, Section 15.3.3.

The applicant also considered a coincident loss of SFP cooling capability. Section 15.3.9 of this report discusses the staff's review of the radiological consequences of SFP boiling.

The staff has reviewed the applicant's analysis and finds that the calculational methods used for the radiological consequence assessment are acceptable, and the radiological consequences calculated by the applicant meet the relevant dose acceptance criteria.

To verify the applicant's assessment, the staff performed independent radiological consequence calculations for the reactor primary coolant pump seizure accident using the RG 1.183 source terms. Tables 15.3-3 and 15.3-1 of this report provide the major parameters and assumptions used by the staff and the results of the staff's radiological consequence analyses, respectively. The offsite radiological consequences calculated by the staff are consistent with those calculated by the applicant.

The staff concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated reactor primary coolant pump seizure accident coincident with the loss of SFP cooling capability will not exceed a small fraction (i.e., 10 percent or 0.025 Sv (2.5 rem) TEDE) of the dose criterion set forth in 10 CFR 50.34.

In DCD Tier 2, Section 6.4.4, Westinghouse reported the results of its radiological consequence analysis for personnel in the main control room during a design-basis locked rotor accident, relying on the VES to limit the radioactivity to which the personnel may be exposed. Section 6.4

of this report describes the staff's review and assessment of the VES. To verify the Westinghouse assessment, the staff performed an independent radiological consequence calculation for the locked rotor accident with VES operation under high-high radiation levels. The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following a design-basis locked rotor accident to meet the dose criterion specified in GDC 19. Tables 15.3-9 and 15.3-1 of this report provide the major assumptions used by the staff and the resulting radiological consequence analysis results for the control room operators, respectively.

The calculation of the dose to the control room operators does not rely on the nuclear island VBS, a non-safety-related system, to meet the requirements of GDC 19. Under some accident circumstances, the non-safety-related VBS would be available to pressurize the control room and the TSC with filtered air and to provide recirculation cleanup. Section 9.4 of this report describes the staff's review and assessment of the non-safety-related VBS. In DCD Tier 2, Section 6.4.4, Westinghouse also reported the results of its radiological consequence analysis for personnel in the main control room and the TSC during a design-basis locked rotor accident with the VBS available. The staff finds reasonable the Westinghouse assertion that, if available, the VBS can mitigate the dose in the main control room and the TSC following a design-basis locked rotor accident to be within 0.05 Sv (5 rem) TEDE. Table 15.3-9 of this report provides the major assumptions used by the staff and the resulting radiological consequence analysis results for the personnel in the control room and the TSC with VBS available.

15.3.3 Radiological Consequences of Rod Cluster Control Assembly Ejection

The mechanical failure of a control rod mechanism pressure housing is postulated to result in the ejection of an RCCA and drive shaft. Because of the resultant opening in the pressure vessel, primary coolant is lost to the containment with concurrent rapid depressurization of the reactor pressure vessel. This mechanical failure causes a rapid positive reactivity insertion, together with an adverse core power distribution, possibly leading to localized fuel rod damage.

The applicant has assumed that 10 percent of the fuel elements will experience cladding failure, releasing the entire fission product inventory in the fuel-cladding gap of these elements. In addition, the applicant assumed that 0.25 percent of the fuel rods may experience fuel melting. The applicant performed its calculations to obtain these parameters using the guidelines provided in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for PWRs." Therefore, the staff finds these assumptions to be acceptable. The applicant submitted a radiological consequence analysis for the control element assembly ejection accident in DCD Tier 2, Section 15.4.8.

The applicant also considered a coincident loss of SFP cooling capability. Section 15.3.9 of this report discusses the staff's review of the radiological consequences of SFP boiling.

The staff has reviewed the applicant's analysis and finds that the calculational methods used for the radiological consequence assessment are acceptable, and the radiological consequences calculated by the applicant meet the relevant dose acceptance criteria.

The applicant assumed that the release of fission products to the environment may occur via either of two pathways. The first pathway involves a release of primary coolant to the containment, which is assumed to leak into the environment at the design leak rate of the containment. In the second pathway, fission products would reach the secondary coolant via the SGs with a maximum total allowable primary-to-secondary leak rate of 1135.6 L/d (300 gal/d), as specified in the AP1000 TS. For both pathways, the applicant assumed that the AP1000 reactor operated at its TS instantaneous primary coolant limit of 2.2 MBq/gm (60 μCi/gm) for DEI-131.

To verify the applicant's assessment, the staff performed independent radiological consequence calculations for the same two pathways, as described above for the RCCA ejection accident, using the RG 1.183 source terms. Tables 15.3-4 and 15.3-1 of this report provide the major parameters and assumptions used by the staff and the results of the staff's radiological consequence analyses, respectively. The offsite radiological consequences calculated by the staff are consistent with those calculated by the applicant.

The staff concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated RCCA ejection accident coincident with the loss of SFP cooling capability will fall well within the dose criterion set forth in 10 CFR 50.34 (i.e., 25 percent or 0.063 Sv (6.3 rem) TEDE).

In DCD Tier 2, Section 6.4.4, Westinghouse reported the results of its radiological consequence analysis for personnel in the main control room during a design-basis RCCA ejection accident, relying on the VES to limit the radioactivity to which the personnel may be exposed. Section 6.4 of this report describes the staff's review and assessment of the VES. To verify the Westinghouse assessment, the staff performed an independent radiological consequence calculation for the RCCA ejection accident with VES operation under high-high radiation levels. The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following a design-basis RCCA ejection accident to meet the dose criterion specified in GDC 19. Tables 15.3-9 and 15.3-1 of this report provide the major assumptions used by the staff and the resulting radiological consequence analysis results for the control room operators, respectively.

The calculation of the dose to the control room operators does not rely on the nuclear island VBS, a non-safety-related system, to meet the requirements of GDC 19. Under some accident circumstances, the non-safety-related VBS would be available to pressurize the control room and the TSC with filtered air and to provide recirculation cleanup. Section 9.4 of this report describes the staff's review and assessment of the non-safety-related VBS. In DCD Tier 2, Section 6.4.4, Westinghouse also reported the results of its radiological consequence analysis for personnel in the main control room and the TSC during a design-basis RCCA ejection accident with the VBS available. The staff finds reasonable the Westinghouse assertion that, if available, the VBS can mitigate the dose in the main control room and the TSC following a design-basis RCCA ejection accident to be within 0.05 Sv (5 rem) TEDE. Table 15.3-9 of this report provides the major assumptions used by the staff and the resulting radiological consequence analysis results for the personnel in the control room and the TSC with VBS available.

15.3.4 Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment

GDC 55, "Reactor Coolant Pressure Boundary Penetrating Containment," contains a provision to ensure isolation of all pipes that are part of the RCPB and penetrate the containment building. GDC 55 also provides that small-diameter pipes that must be continuously connected to the primary coolant system to perform necessary functions may be acceptable based on some other defined bases. For these lines, methods of mitigating the consequences of a rupture are necessary because the lines cannot be isolated automatically. For the AP1000 design, the two small lines in this category are

- the RCS sample line
- the discharge line from the CVCS to the liquid radwaste system (WLS)

No instrument lines carry primary coolant outside containment in the AP1000 design.

When boron dilution operations generate excess primary coolant inventory, the CVCS purification flow is diverted out of containment to the WLS. Before passing outside containment, the flow stream passes through the CVCS HXs and mixed bed demineralizer for processing. The flow leaving the containment will be at a temperature of less than 60 °C (140 °F). The flow from a postulated break in this line is limited to the CVCS purification normal flow rate of 379 L/min (100 gpm). In DCD Tier 2, Section 15.6.2, considering the low temperature of the breakflow and the reduced iodine activity because of demineralization for the postulated break in the discharge line from the CVCS to the WLS, the applicant proposed, and the staff accepted, that the postulated break in the RCS sample line is the more limiting event for the radiological consequence assessment.

The RCS sample line includes a flow restrictor at the point of sample to limit the breakflow to less than 492 L/min (130 gpm). Because the sample line isolation valves are open only when sampling is ongoing, and there are multiple indications that a break has occurred in the sample line, the applicant assumed, and the staff accepted, that the breakflow isolation time will be less than 30 minutes. The applicant assumed the fluid escaping the break to be at the equilibrium primary coolant iodine concentration limits in the AP1000 TS, with an assumed accident-initiated iodine spike that increases the rate of iodine release from the fuel into the coolant by a factor of 500. The staff finds this to be acceptable and in agreement with guidance on assumptions for radioactivity released from a small line break found in SRP Section 15.6.2, "Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment." The applicant submitted a radiological analysis for a small line failure in DCD Tier 2, Section 15.6.2.

The applicant also considered a coincident loss of SFP cooling capability. Section 15.3.9 of this report discusses the staff's review of the radiological consequences of SFP boiling.

The staff has reviewed the applicant analysis and finds that the calculational methods used for the radiological consequence assessment are acceptable, and the radiological consequences calculated by the applicant meet the relevant dose acceptance criteria. To verify the applicant's assessment, the staff performed independent radiological consequence calculations for a postulated small line break accident. The staff assumed that a temporary increase in the primary coolant iodine concentration (iodine spike) occurred as a result of the power/pressure transient caused by the small line break accident. Before the postulated accident, the AP1000 reactor was assumed to operate at the AP1000 TS equilibrium concentration limit of 37 kBq/gm (1.0 μCi/gm) for DEI-131 in the primary coolant.

The iodine spike generated during the accident is assumed to increase the release rate of iodine from the fuel by a factor of 500. This increase in the release rate results in a rising iodine concentration in the primary coolant during the course of the accident.

Tables 15.3-5 and 15.3-1 of this report provide the major parameters and assumptions used by the staff and the results of the staff's radiological consequence analyses, respectively. The offsite radiological consequences calculated by the staff are consistent with those calculated by the applicant.

The staff concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated small line break accident coincident with the loss of SFP cooling capability will not exceed a small fraction (i.e., 10 percent or 0.025 Sv (2.5 rem) TEDE) of the dose criterion set forth in 10 CFR 50.34.

In DCD Tier 2, Section 6.4.4, Westinghouse reported the results of its radiological consequence analysis for personnel in the main control room during a design-basis small line break accident, relying on the VES to limit the radioactivity to which the personnel may be exposed. Section 6.4 of this report describes the staff's review and assessment of the VES. To verify the Westinghouse assessment, the staff performed an independent radiological consequence calculation for the small line break accident with VES operation under high-high radiation levels. The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following a design-basis small line break accident to meet the dose criterion specified in GDC 19. Tables 15.3-9 and 15.3-1 of this report provide the major assumptions used by the staff and the resulting radiological consequence analysis results for the control room operators, respectively.

The calculation of the dose to the control room operators does not rely on the nuclear island VBS, a non-safety-related system, to meet the requirements of GDC 19. Under some accident circumstances, the non-safety-related VBS would be available to pressurize the control room and the TSC with filtered air and to provide recirculation cleanup. Section 9.4 of this report describes the staff's review and assessment of the non-safety-related VBS. In DCD Tier 2, Section 6.4.4, Westinghouse also reported the results of its radiological consequence analysis for personnel in the main control room and the TSC during a design-basis small line break accident with the VBS available. The staff finds reasonable the Westinghouse assertion that, if available, the VBS can mitigate the dose in the main control room and the TSC following a design-basis small line break accident to be within 0.05 Sv (5 rem) TEDE. Table 15.3-9 of this report provides the major assumptions used by the staff and the resulting radiological consequence analysis results for the personnel in the control room and TSC with VBS available.

15.3.5 Radiological Consequences of a Steam Generator Tube Rupture

The applicant has evaluated the radiological consequences of a postulated SGTR accident and provided a radiological consequence analysis for the accident in DCD Tier 2, Section 15.6.3. The staff has reviewed the applicant's analysis and finds that the calculational methods used for the radiological consequence assessment are acceptable, and the radiological consequences calculated by Westinghouse meet the relevant dose acceptance criteria.

The applicant also considered a coincident loss of SFP cooling capability. Section 15.3.9 of this report discusses the staff's review of the radiological consequences of SFP boiling.

To verify the applicant's assessments, the staff performed independent radiological consequence calculations for two scenarios for the SGTR accident. For Case 1, the staff assumed that a temporary increase in the primary coolant iodine concentration (iodine spike) occurred as a result of the power/pressure transient caused by the SGTR. Before the postulated accident, the AP1000 reactor was assumed to operate at the AP1000 TS equilibrium iodine concentration limit of 37 kBq/gm (1.0 μCi/gm) for DEI-131 in the primary coolant. The iodine spike generated during the accident is assumed to increase the release rate of iodine from the fuel by a factor of 335, resulting in a rising iodine concentration in the primary coolant during the course of the accident.

For Case 2, the staff assumed that previous reactor operation had resulted in a primary coolant concentration equal to the maximum instantaneous concentration limit of 2.2 MBq/gm (60 μCi/gm) for DEI-131, specified in the AP1000 TS. Tables 15.3-6 and 15.3-1 of this report provide the major parameters and assumptions used by the staff and the results of the staff's radiological consequence analyses for the EAB and LPZ and for the control room, respectively. The offsite radiological consequences calculated by the staff are consistent with those calculated by the applicant.

The staff concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated SGTR accident with accident-induced iodine spiking and coincident with the loss of SFP cooling capability will not exceed a small fraction (i.e., 10 percent or 0.025 Sv (2.5 rem) TEDE) of the dose criterion set forth in 10 CFR 50.34.

The staff concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated SGTR accident with the reactor coolant at the TS maximum value of 2.2 MBq/gm (60 μCi/gm) for DEI-131 and coincident with the loss of SFP cooling capability will not exceed the dose criterion set forth in 10 CFR 50.34 (i.e., 0.25 Sv (25 rem) TEDE).

In DCD Tier 2, Section 6.4.4, Westinghouse reported the results of its radiological consequence analysis for personnel in the main control room during a design-basis SGTR, relying on the VES to limit the radioactivity to which the personnel may be exposed. Section 6.4 of this report describes the staff's review and assessment of the VES. To verify the Westinghouse assessment, the staff performed an independent radiological consequence calculation for the

SGTR with VES operation under high-high radiation levels. The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following a design-basis SGTR to meet the dose criterion specified in GDC 19. Tables 15.3-9 and 15.3-1 of this report provide the major assumptions used by the staff and the resulting radiological consequence analysis results for the control room operators, respectively.

The calculation of the dose to the control room operators does not rely on the nuclear island VBS, a non-safety-related system, to meet the requirements of GDC 19. Under some accident circumstances, the non-safety-related VBS would be available to pressurize the control room and the TSC with filtered air and to provide recirculation cleanup. Section 9.4 of this report describes the staff's review and assessment of the non-safety-related VBS. In DCD Tier 2, Section 6.4.4, Westinghouse also reported the results of its radiological consequence analysis for personnel in the main control room and the TSC during a design-basis SGTR with the VBS available. The staff finds reasonable the Westinghouse assertion that, if available, the VBS can mitigate the dose in the main control room and the TSC following a design-basis SGTR to be within 0.05 Sv (5 rem) TEDE. Table 15.3-9 of this report provides the major assumptions used by the staff and the resulting radiological consequence analysis results for the personnel in the control room and the TSC with VBS available.

15.3.6 Radiological Consequences of LOCAs

In DCD Tier 2, Section 15.6.5, the applicant analyzed a hypothetical design-basis LOCA. The applicant concluded that certain bounding sets of atmospheric relative concentration values (i.e., χ/Qs) specified in DCD Tier 2, Section 2.3, in conjunction with the use of natural deposition of fission product aerosol within the containment and the control of the pH of the water in the containment to prevent iodine evolution, are sufficient to provide reasonable assurance that the calculated radiological consequences of a postulated design-basis LOCA will fall within the relevant dose criteria established in 10 CFR 50.34 and in GDC 19.

All of the fission product releases stemming from the LOCA result from containment leakage. The AP1000 design does not have ESF systems outside containment. Therefore, the radiological consequence analyses do not consider leakage from the ESF systems. The containment was assumed to leak at its design leak rate of 0.1 wt% per day for the first 24 hours and at half of that rate (0.05 wt% per day) for the remaining duration of the accident (30 days). The AP1000 design provides neither an ESF filtration (e.g., charcoal adsorbers) nor a safety-related containment spray system.

The applicant also considered a coincident loss of SFP cooling capability. Section 15.3.9 of this report discusses the staff's review of the radiological consequences of SFP boiling.

For the DSER, the staff had not completed its evaluation of the applicant's assumptions on aerosol removal in containment, as discussed in RAIs 470.009 and 470.011. Until the resolution of the issues with aerosol removal in containment, the staff could not complete its independent radiological consequence analysis of a postulated design-basis LOCA. This was Open Item 15.3.6-1. With the resolution of DSER Open Item 15.3-1 on aerosol removal, as discussed below, the staff could complete its independent analyses to confirm the applicant's assessment of the radiological consequences of the design-basis LOCA. Therefore, DSER Open Item 15.3.6-1 is closed.

The AP1000 design does not provide an active containment atmosphere cleanup system. Instead, the design relies on natural aerosol removal processes for deposition in the containment, such as gravitational settling and plateout on containment surfaces through diffusiophoresis and thermophoresis. Appendix 15B to DCD Tier 2 discusses the removal of airborne activity from the containment atmosphere. The applicant has provided a containment spray system for accident management following a severe accident as part of the AP1000 fire protection system design (discussed in Section 19.2.3.3.9 of this report). The containment spray system design is not safety-related and is not intended to be used during or following a DBA. Therefore, radiological consequence assessments give the containment spray system no credit for mitigation of radiological releases following a DBA.

The AP1000 LOCA offsite doses do not scale up from the AP600 proportionately with the change in the power or T-H conditions in the containment. The main reason is that, given the same leak rates, the amount of the release is a sole function of the airborne fission product mass, which is proportional to the core inventory. The AP1000 inventory is about twice that of the AP600 (about 70 percent higher power with a longer fuel cycle). Consequently, the removal rate for the AP1000 must be at least twice that of the AP600 to achieve the same offsite doses. The calculations performed by Westinghouse and the confirmatory uncertainty analysis performed by the staff show that the current containment design does not provide for a removal rate of twice that of the AP600. However, by adjusting the atmospheric dispersion factors (χ/Qs) lower than those used in the AP600 design, the radiological consequences of the LOCA remain acceptable. Because of this, the siting of the AP1000 design is more limited than for the AP600.

Applying credit for aerosol removal through natural processes requires input from T-H and aerosol behavior models. The basis document defining the revised accident source term, NUREG-1465, does not specify an associated T-H scenario, or methodology or acceptance criteria for aerosol removal. The alternative source term regulatory guidance, RG 1.183, also does not specify these items. NUREG-1465 describes a source term that was derived from an examination of a set of severe accident sequences for LWRs and is intended to be representative or typical and does not imply a specific scenario, much less the worst case.

The determination of aerosol removal rates is simplified for a containment shown to have a well-mixed atmosphere. The AP1000 design relies on natural circulation currents enhanced by the PCS to inhibit stratification of the containment atmosphere. DCD Tier 2, Appendix 6A, discusses the physical mechanisms of natural circulation mixing that occur in the AP1000. Section 6.2.5.3 of this report provides the staff's discussion of natural circulation within the AP1000 containment.

In DCD Tier 2, Table 15B-1, the applicant provided aerosol removal coefficient values starting at the onset of a gap release through the first 24 hours into a DBA. The values range from 0.287/h to 1.141/h. The aerosol removal coefficients calculated by the applicant neglect steam condensation on the airborne particles, turbulent diffusion, and turbulent agglomeration. The assumed source aerosol size is conservatively small, because it is at the low end of the mass mean aerosol size range of 1.5 μm to 5.5 μm used in NUREG/CR-5966, "A Simplified Model of Aerosol Removal by Containment Sprays," issued June 1993. Selection of a small aerosol size would underestimate removal by sedimentation.

The aerosol removal coefficients calculated by Westinghouse for the AP1000 are based on a single set of parameters, and Westinghouse performed sensitivity studies to determine if changing the parameters would affect the overall removal coefficients. The staff felt that some parameters chosen originally by Westinghouse were not conservative, as would be required for use in design-basis analyses, nor were these parameters likely to be suitable for use as point estimates, considering the lack of knowledge and uncertainty in some areas of post-LOCA aerosol formation and detailed containment response.

In the past, the staff and industry evaluated aerosol removal through well-established models of spray removal or condensation. The AP1000 application relies on natural deposition processes that depend strongly on local T-H conditions. While gravitational settling is relatively easy to understand, aerosol removal through diffusiophoresis and thermophoresis is much more complex. Diffusiophoresis is associated with steam condensation on the heat sinks and depends on the condensation steam mass flux. Thermophoresis relies only on the temperature gradient close to the surface on which the particles would be deposited. Thermophoresis is more subtle than the other two natural deposition processes. Because the temperature gradient cannot be measured or easily calculated, its model uses the heat flux at the surface divided by the thermal conductivity of the gas adjacent to the surface as an equivalent measure of the driving force. Simultaneous occurrence of the two phoretic processes introduces an additional level of complexity.

The Westinghouse methodology includes industry's Modular Accident Analysis Program (MAAP) code, an integrated accident analysis program, to establish T-H boundary conditions as an input to an aerosol code (STARNAUA). To determine the acceptability of the Westinghouse modeling, the staff audited Westinghouse calculations of the containment removal coefficients. The audit revealed that the heat flux used by Westinghouse included the convection, the thermal radiation, and the decay heat from airborne fission products. Thermal radiation and decay heat do not contribute to the temperature gradient that drives thermophoresis and their use caused the overall aerosol removal to be nonrealistic and nonconservative. Westinghouse recalculated the overall aerosol removal coefficients by correcting this error.

In its independent evaluation of aerosol removal coefficients, the staff considered the same natural processes for removing aerosols from the containment atmosphere over the entire period of an accident (30 days). These processes include the sedimentation mechanism of gravitational settling, such as aerosol agglomeration, and the phoretic mechanisms of diffusiophoresis and thermophoresis.

The staff contracted Sandia National Laboratory to perform quantitative analyses of uncertainties in predicting the aerosol removal rates. The initiating event, used in the analysis (3BE-1 sequence), is a double-ended break of a DVI 10.2-cm- (4-in.-) diameter line. The break is assumed to be in a larger compartment of the passive core cooling system (PXS). The sequence includes the water spillage into the PXS-B compartment from one of the lost accumulators and one of the CMTs. The analysis assumes that one CMT and one accumulator (in the intact DVI train) remain available to inject water into the RV, which is not sufficient to keep the core covered. This deficiency in core cooling leads to degradation and/or melt of the fuel. Eventually, the water level in the containment reaches the break level and spills into the vessel, arresting the core degradation before potential failure of the vessel lower head.

As part of the staff's review, the aerosol behavior in the AP1000 containment was predicted using the MELCOR integrated accident analysis code, which includes the MAEROS aerosol mechanics code. The staff used the results of a fully integrated MELCOR analysis of the AP1000 3BE-1 accident, performed by the staff's contractor, Energy Research, Inc., to develop a simplified containment model for the uncertainty analysis. The NUREG-1465 radiological source term for the gap release and in-vessel release phases were used in place of the source term predicted in the fully integrated analysis. The uncertainty analysis considered those MELCOR parameters known to affect aerosol settling and depletion to be uncertain within a range of values, represented by an assumed distribution function. A Monte Carlo method, which randomly samples the uncertain parameters and performs a large number of separate MELCOR analyses, estimated the effect of the uncertain physics parameters on the aerosol removal rate.

In its evaluation of aerosol removal rates, the staff used the containment geometry (e.g., volume, upward facing surface area) provided by Westinghouse and the fission product release timing, fractions, and release rates as described in NUREG-1465.

The principal uncertainties in aerosol properties and aerosol behavior considered in the staff's analyses included the following:

- aerosol size and distribution
- aerosol void fraction and particle shape factors
- aerosol material density
- nonradioactive aerosol mass
- particle slip coefficient
- sticking probability for agglomeration
- boundary layer thickness for diffusion deposition
- thermal accommodation coefficient for thermophoresis
- ratio of thermal conductivity of particle to gas
- turbulent energy dissipation
- multipliers on heat and mass transfer to containment shell

The Westinghouse calculation of aerosol removal coefficients is based on an analysis of a single T-H scenario and uses a single aerosol model without providing an uncertainty analysis. The staff believes that the Westinghouse approach, though potentially acceptable, represents a single BE result. Westinghouse used T-H conditions associated with the 3BE-1 severe accident sequence. The staff concludes that using the T-H conditions associated with the 3BE-1 severe accident sequence represents the spectrum of accidents evaluated for the AP1000 for the following reasons:

- The conditions are representative of the 3BE accident class, which is the dominant contributor to the core damage frequency for the AP1000.

- The T-H conditions for 3BE accidents are typical of most of the analyzed sequences because the majority of severe accident sequences analyzed for the AP1000 design are fully depressurized and reflooded, given the highly reliable ADS.

- The corresponding T-H profiles for these depressurized and reflooded cases are sufficiently similar.

- The use of a fully depressurized, low-pressure accident sequence in conjunction with the source term described in NUREG-1465 is appropriate because the release fractions for the source terms presented in NUREG-1465 are intended to be representative or typical of those associated with a low-pressure core melt accident.

Therefore, the staff concludes that the 3BE-1 accident sequence is appropriate for determining the amount of credit to give to the natural aerosol removal processes in the AP1000 containment. In its independent uncertainty analysis, the staff did not employ the T-H calculated by Westinghouse using the MAAP code. The staff's uncertainty analysis did not include differences between the staff and Westinghouse calculations with respect to containment T-H and containment modeling as variables for study.

Although the choice of scenario is acceptable, the staff believes that a BE approach requires an evaluation of the associated uncertainties. The staff used an alternative T-H code (MELCOR) as an input to a Monte Carlo sampling (120 runs) of the above-listed parameters affecting aerosol behavior. Engineering judgment was used to choose parameters as well as for the range and distribution of their values, after several discussions between the staff and the contractor. The resultant distribution of possible aerosol removal coefficients has a 95-percent level of confidence. The 5th, 20th, 40th, 45th, 50th, 55th, 60th, 80th, and 95th percentiles, as depicted in Figure 15.3.6-1 of this report and documented in Table 15.3.6-1 of this report, provide the uncertainty distribution.

In the uncertainty analysis performed for the staff, the conservative lower bound (5th percentile) aerosol removal coefficient ranges from 0.07/h to 1.26/h for the first 24 hours into a DBA (shown in Table 15.3-8 of this report). The BE median (50th percentile) aerosol removal coefficient ranges from 0.3/h to 1.35/h. The traditional regulatory approach is to accept a bounding value, which would generally be the 5th percentile, as the maximum bounding value, where there is an estimated 5 percent chance that the aerosol removal coefficients will be lower than assumed, thereby resulting in higher calculated doses. In this particular case, however, the staff proposes the use of the median value for the following reasons:

- In an alternative source term (AST) pilot application for Perry, the staff had previously accepted the 50th percentile value for steamline deposition, based on the NRC Office of Nuclear Regulatory Research opinion that it is appropriate given other conservatisms built into the other parts of the analysis.

- The staff believes that the selected scenario belongs to a worst-case category.

- The median values are least affected by the user's sampling initial conditions.

- The choice of the initial ranges and distributions of the selected parameters is highly subjective.

- Both the AST and the modeling of containment leakage have built-in conservativisms.

- The dose calculation code requires yet another averaging of the aerosol removal coefficients for the specified time periods.

- The independent MELCOR-calculated aerosol removal coefficients are grouped mostly well above the 5th percentile lower bound.

It is important to emphasize that it is the staff's judgment that the acceptance of the 50th percentile for use in DBA analyses is appropriate for this particular safety analysis because an underlying conservative bias has been built into the staff's uncertainty methodology (e.g., the choice of the ranges and distributions of the sampled parameters). The staff believes that different choices of initial ranges and distributions, and/or the use of a different uncertainty methodology, may not be acceptable.

The uncertainty analysis also indicated that, for the staff's model as implemented in MELCOR, phoretic processes (thermophoresis and diffusiophoresis) together dominate for the first 4 hours of the LOCA and constitute 90 percent of aerosol removal. After that, gravitational settling is the dominant removal mechanism.

Although the Westinghouse-calculated aerosol removal coefficient values lie within the staff's uncertainty analysis upper and lower bounds for portions of the early part of the accident, they generally do not lie below the median value calculated by the staff. While the staff does find that gravitational settling, thermophoresis, and diffusiophoresis are physical processes that occur in the AP1000 containment, and credit may be taken for aerosol removal through these processes, the staff does not approve the specific Westinghouse-calculated aerosol removal coefficient values. These values are an intermediate product used in the dose analysis and are not subject to any regulations, per se. Staff independent analyses using the Westinghouse-supplied χ/Qs and plant parameters result in acceptable doses, as discussed below. Thus, while the staff and Westinghouse diverge on values for the intermediate steps in the dose calculations, the staff agrees with the overall conclusion that the AP1000 design results in acceptable doses.

The staff performed an independent dose analysis with the median aerosol removal coefficient values from the staff's uncertainty analysis, along with other analysis parameters and the bounding hypothetical atmospheric dispersion factors provided by Westinghouse, and the results fall within the dose criteria of 10 CFR 50.34 and GDC 19. The staff performed a sensitivity analysis, which resulted in calculated doses that remain below the regulatory acceptance criteria for aerosol removal coefficients as low as those given in the 20th percentile in the staff's uncertainty analysis.

The staff finds the radiological consequence analysis of the postulated DBA LOCA acceptable, based on the Westinghouse DCD Tier 2, Chapter 15, plant parameters used in the staff's analysis, the staff-calculated aerosol removal coefficient estimates (50th percentile, 95 percent confidence), and the latest revision to the AP1000 χ/Qs, as documented in the Revision 5 response to DSER Open Item 15.3-1, dated June 21, 2004. Westinghouse will include the revised information, including χ/Qs, in revision 12 of the AP1000 DCD and the staff will confirm. With this basis, the doses meet the regulatory criteria of 10 CFR 50.34 and GDC 19 and are, therefore, acceptable.

In the DSER, the staff stated that it would perform an independent evaluation of the bounding accident sequence and the aerosol behavior and removal rates corresponding to the selected bounding accident sequence in the containment following a DBA. This was identified as DSER Open Item 15.3-1. The staff has completed its evaluation and finds that the differences between the resulting radiological consequences calculated using either Westinghouse's or the staff's aerosol removal rates are insignificant. Accordingly, analysis credit for aerosol removal through natural processes is found acceptable, and DSER Open Item 15.3-1 is closed.

Because of the unique nature of the AP1000 design, which enhances natural aerosol removal phenomena (such as the enhanced condensation of steam by external cooling of the containment vessel instead of an internal containment spray), the staff has approved the use of this T-H profile specifically for the AP1000. The NRC does not intend credit for aerosol removal because of diffusiophoresis and thermophoresis to be generic for other plant designs, and this practice must be approved on a case-by-case basis. Because the staff did not explicitly find the input values for the aerosol removal coefficient used in the Westinghouse dose calculation to be acceptable, the NRC staff must review any changes to the LOCA calculation made by a COL applicant or licensee of an AP1000 plant.

In DCD Tier 2, Section 6.4.4, Westinghouse reported the results of its radiological consequence analysis for personnel in the main control room during a design-basis LOCA, relying on the VES to limit the radioactivity to which the personnel may be exposed. Section 6.4 of this report describes the staff's review and assessment of the VES. To verify the Westinghouse assessment, the staff performed an independent radiological consequence calculation for the LOCA with VES operation under high-high radiation levels. The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following a design-basis LOCA to meet the dose criterion specified in GDC 19. Tables 15.3-9 and 15.3-1 of this report provide the major assumptions used by the staff and the resulting radiological consequence analysis results for the control room operators, respectively.

The calculation of the dose to the control room operators does not rely on the nuclear island VBS, a non-safety-related system, to meet the requirements of GDC 19. Under some accident circumstances, the non-safety-related VBS would be available to pressurize the control room and the TSC with filtered air and to provide recirculation cleanup. Section 9.4 of this report describes the staff's review and assessment of the non-safety-related VBS. In DCD Tier 2, Section 6.4.4, Westinghouse also reported the results of its radiological consequence analysis for personnel in the main control room and the TSC during a design-basis LOCA with the VBS available. The staff finds the Westinghouse assertion reasonable that, if available, the VBS can mitigate the dose in the main control room and the TSC following a design-basis LOCA to be within 0.05 Sv (5 rem) TEDE. Table 15.3-9 of this report provides the major assumptions used by the staff and the resulting confirmatory analysis results.

15.3.7 Radiological Consequences of a Fuel-Handling Accident

In DCD Tier 2, Section 15.7.4, the applicant presented its analyses of the radiological consequences of a postulated FHA. For the AP1000 design, an FHA can be postulated to occur either inside containment or in the fuel-handling area inside the auxiliary building. If the FHA occurs in the containment, closure of the containment purge lines based on the detection of high airborne radioactivity can terminate the release of fission products. The applicant assumed, in accordance with guidance in RG 1.183, that fission products are directly released to the environment within a 2-hour period without credit for any iodine removal processes.

For the FHA, the applicant assumed that a single fuel assembly that has undergone 24 hours of decay time is dropped, such that the activity in the gap of every rod in the dropped assembly is released. The kinetic energy of the falling fuel assembly is assumed to break open the maximum possible number of fuel rods using perfect mechanical efficiency. Instantaneous release of noble gases and radioiodine vapor from the gaps of the broken rods (8 percent of I-131, 10 percent of Kr-85, and 5 percent of other iodine and noble gas inventories in the fuel rod) is assumed to occur, with the released gases bubbling up through the fuel pool water. The fuel pool water has an assumed effective decontamination factor of 200 for total iodine. These gap fractions agree with RG 1.183 guidance. The applicant assumed that iodine in the particulate form is not volatile and, therefore, is not released. In accordance with RG 1.183 guidance, the applicant assumed that the particulate CsI is converted instantaneously to the elemental form of iodine when it is released from the fuel into the low-pH pool water.

The applicant also considered a coincident loss of SFP cooling capability. Section 15.3.9 of this report discusses the staff's review of the radiological consequences of SFP boiling.

The staff has reviewed the applicant's analysis and finds that the calculational methods used for the radiological consequence assessment are acceptable, and the radiological consequences calculated by the applicant meet the relevant dose acceptance criteria.

To verify the applicant's assessments, the staff performed independent radiological consequence calculations for the FHA occurring 24 hours after shutdown, coincident with a loss of the SFP cooling capability. Tables 15.3-10 and 15.3-1 of this report provide the major parameters and assumptions used by the staff and the results of the staff's radiological consequence analyses, respectively. The offsite radiological consequences calculated by the staff are consistent with those calculated by Westinghouse.

The staff concludes that the AP1000 design, as bounded by the atmospheric relative concentrations proposed by the applicant, will provide reasonable assurance that the radiological consequences of a postulated FHA at 24 hours after shutdown with the loss of SFP cooling capability will fall well within the dose criterion set forth in 10 CFR 50.34 (i.e., 25 percent or 0.063 Sv (6.3 rem) TEDE).

In RAI 630.052, the NRC staff asked the applicant to justify not including a TS LCO for a decay time limit related to the assumption used in the radiological consequences analysis of the FHA. The applicant, in response to the RAI, stated that it had performed a sensitivity study in which the FHA was assumed to occur 24 hours after shutdown, and the resulting doses remain below 10 CFR 50.34 guidelines. The applicant updated the DCD to include a paragraph discussing the evaluation of the FHA, assuming a decay time of 24 hours. The applicant asserted that a decay time LCO is not necessary because the evaluation of the FHA at 24 hours shows that the capability of the AP1000 design to meet the regulatory dose acceptance criteria is not sensitive to the decay time. The staff believes that, in order to exclude a TS LCO for the decay time, the design-basis FHA dose analysis must assume a decay time that is clearly less than the time physically needed to begin moving fuel assemblies out of the core following unit shutdown for refueling. The staff does not consider 100 hours to be short enough. The applicant did not revise the design-basis FHA dose analysis, which continued to include the 100-hour decay time assumption. Additionally, in the DCD Tier 2, Section 15.7.4.5, discussion of the evaluation of the FHA at 24 hours, the applicant did not discuss the impact of the decay time on control room habitability from an FHA at 24 hours. The staff did not consider this issue to be resolved at the time of issuance of the DSER. This was Open Item 15.3.7-1. To resolve this issue, the applicant revised the design-basis FHA to assume that the fuel breached has been part of a critical operating core 24 hours before the accident occurs. The revised analysis evaluated the radiological consequences offsite and in the control room. The applicant also added refueling operations TS 3.9.7, "Decay Time," which requires that the reactor be shut down for at least 100 hours before movement of irradiated fuel in the reactor pressure vessel. Therefore, DSER Open Item 15.3.7-1 is closed.

In DCD Tier 2, Section 6.4.4, Westinghouse reported the results of its radiological consequence analysis for personnel in the main control room during a design-basis FHA, relying on the VES to limit the radioactivity to which the personnel may be exposed. Section 6.4 of this report describes the staff's review and assessment of the VES. To verify the Westinghouse assessment, the staff performed an independent radiological consequence calculation for the FHA with VES operation under high-high radiation levels. The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following a design-basis FHA to meet the dose criterion specified in GDC 19. Tables 15.3-9 and 15.3-1 of this report provide the major assumptions used by the staff and the resulting radiological consequence analysis results for the control room operators, respectively.

The calculation of the dose to the control room operators does not rely on the nuclear island VBS, a non-safety-related component, to meet the requirements of GDC 19. Under some accident circumstances, the non-safety-related VBS would be available to pressurize the control room and the TSC with filtered air and to provide recirculation cleanup. Section 9.4 of this report describes the staff's review and assessment of the non-safety-related VBS. In DCD Tier 2, Section 6.4.4, Westinghouse also reported the results of its radiological consequence analysis for personnel in the main control room and the TSC during a design-basis FHA with the VBS available. The staff finds reasonable the Westinghouse assertion that, if available, the VBS can mitigate the dose in the main control room and the TSC following a design-basis FHA to be within 0.05 Sv (5 rem) TEDE. Table 15.3-9 of this report provides the major assumptions used by the staff and the resulting radiological consequence analysis results for the personnel in the control room and the TSC with VBS available.

15.3.8 Offsite Radiological Consequences of Liquid Tank Failure

SRP Section 15.7.3, "Postulated Radioactive Releases due to Liquid-Containing Tank Failures," contains guidance on review of the failure of a tank containing liquid. The following regulations provided the basis for the acceptance criteria specified in this SRP section:

- GDC 60, "Control of Releases of Radioactive Materials to the Environment," as it relates to the ability of the design of the radioactive waste management system to control the release of radioactive materials to the environment

- 10 CFR Part 20, as it relates to radioactivity in effluents to unrestricted areas

The failure of the most limiting (i.e., in terms of offsite radiological consequences) WLS equipment outside the containment does not result in radionuclide concentrations in water at the nearest potable water supply in an unrestricted area exceeding the liquid effluent concentration limits for the corresponding radionuclides, specified in Appendix B to 10 CFR Part 20 (Table 2, Column 2). The design of the WLS incorporates specific design features to mitigate the effects of failure, if the WLS does not meet the above requirements of 10 CFR Part 20.

In the AP1000 design, tanks containing radioactive fluids are located inside plant structures. In the event of a tank failure, the floor drains would drain the liquid to the auxiliary building sump. From the sump, the water would be directed to the waste holdup tank. Because SRP Section 15.7.3 states that credit cannot be taken for liquid retention by unlined building foundations, the assumption is made that release to the environment is possible.

DCD Section 15.7.3 includes a commitment for a COL applicant to perform a site-specific offsite radiological consequence analysis, including the corresponding source term resulting from a postulated liquid tank failure. The staff finds this commitment to be acceptable because the assessment of offsite radiological consequences of liquid tank failures depends upon site-specific parameters, such as the mode of transport of radioactive fluid resulting from the failure to the region of potable water supply, the location of potable water supply, the characteristics of the soil through which the transport occurs, and the available dilution by waterbodies before the radioactive liquid reaches the potable water supply. The staff will evaluate the site-specific analysis in accordance with SRP Section 15.3.7 for each COL applicant referencing the AP1000 standard design. This is COL Action Item 15.3.8-1.

15.3.9 Radiological Consequences of Loss of Spent Fuel Pool Cooling

For the radiological consequences analysis of each DBA, Westinghouse evaluated the added radiological consequences of SFP boiling because of the loss of SFP cooling capability.

The SFS is designed to perform the following functions:

- remove heat from the SFP and the IRWST
- remove radioactive corrosion and fission products from the SFP, the IRWST, and the refueling cavity
- transfer water between the IRWST and the refueling cavity for refueling operations

The system consists of redundant trains. Each train includes a pump, an HX, a filter, and a demineralizer. However, the SFS is a non-safety-related system. Therefore, the applicant assumed, and the staff agrees, that a loss of SFP cooling capability should be analyzed coincident with DBAs.

The loss of SFP cooling could result in the pool reaching boiling, and a portion of the radioactive iodine in the SFP water could be released to the environment. Without actions to provide makeup water to the SFP, boiling is assumed to commence at 8.8 hours after loss of SFP cooling capability. The applicant has calculated that the dose consequences from this source are less than 0.1 mSv (0.01 rem) TEDE, both offsite and to the control room operators. This dose is added to the dose consequences of each DBA to find the overall dose consequences of the DBA coincident with loss of SFP cooling.

To verify the applicant's assessment, the staff performed an independent radiological consequence calculation for the loss of the SFP cooling capability. Tables 15.3-11 and 15.3-1 of this report provide the major parameters and assumptions used by the staff and the results of the staff's radiological consequence analyses, respectively. The offsite radiological consequences calculated by the staff are consistent with those calculated by the applicant.

15.3.10 Conclusions

The staff has reviewed the radiological consequences analyses of the DBAs described in DCD Tier 2, Chapter 15, for the AP1000 design. Based on the evaluation discussed above, the staff concludes that the AP1000 design meets 10 CFR 50.34(a)(1)(ii)(D) dose criteria and the offsite dose acceptance criteria, as given in RG 1.183 for these accidents.

The staff finds reasonable assurance that the VES, under high-high radiological conditions as described in DCD Tier 2, Section 6.4, can mitigate the dose in the main control room following DBAs to meet the dose criterion specified in GDC 19.

The staff finds it reasonable that, if available, the non-safety-related VBS can mitigate the dose in the main control room and the TSC following DBAs to be within 0.05 Sv (5 rem) TEDE.

COL Action Item 15.3.8-1, regarding a site-specific analysis of the offsite radiological consequences of a liquid tank failure, explains that the COL applicant should perform a site-specific offsite radiological consequences analysis of the postulated liquid tank failure to confirm that the plant meets the applicable regulations on radioactive waste management systems and radiological effluents. The COL applicant should submit in the plant specific application the radiological consequences analysis for the staff to review and approve.

Fig. 15.2.7.6

Pressure Drop vs Core Steaming Rate

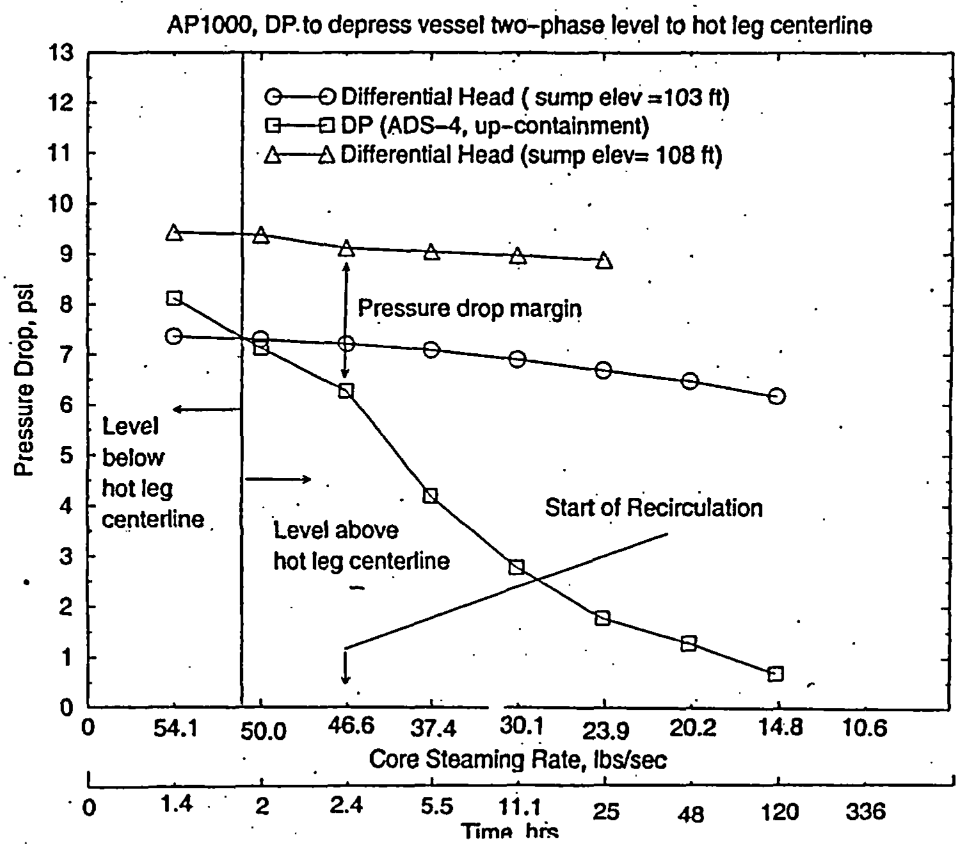

Table 15.3-1 Staff-Calculated Radiological Consequences of Design-Basis Accidents (Total Effective Dose Equivalent (TEDE))

Postulated Accident	EAB	LPZ	Control Room
Loss of coolant accident	190 mSv (19 rem)	150 mSv (15 rem)	34 mSv (3.4 rem)
Main steamline break outside containment			
With accident-initiated iodine spike	2 mSv (0.2 rem)	8 mSv (0.8 rem)	13 mSv (1.3 rem)
With preaccident iodine spike	<1 mSv (<0.1 rem)	1 mSv (0.1 rem)	9 mSv (0.9 rem)
Reactor coolant pump shaft seizure			
With feedwater available	<1 mSv (<0.1 rem)	<1 mSv (<0.1 rem)	8 mSv (0.8 rem)
Without feedwater available	<1 mSv (<0.1 rem)	<1 mSv (<0.1 rem)	12 mSv (1.2 rem)
Rod ejection accident	15 mSv (1.5 rem)	24 mSv (2.4 rem)	11 mSv (1.1 rem)
Fuel-handling accident	24 mSv (2.4 rem)	10 mSv (1.0 rem)	29 mSv (2.9 rem)
Small line break accident	10 mSv (1.0 rem)	4 mSv (0.4 rem)	14 mSv (1.4 rem)
Steam generator tube rupture			
With accident-initiated iodine spike	5 mSv (0.5 rem)	7 mSv (0.7 rem)	26 mSv (2.6 rem)
With preaccident iodine spike	10 mSv (1.0 rem)	6 mSv (0.6 rem)	50 mSv (5 rem)
Spent fuel pool boiling	n/a*	<0.1 mSv (<0.01 rem)	<0.1 mSv (<0.01 rem)

* n/a, not applicable

Table 15.3-2 Assumptions Used to Evaluate the Radiological Consequences of the Main Steamline Break Accident Outside Containment

Parameter	Value	
Power level, MWt	3468	
Reactor primary coolant iodine concentrations		
Accident-initiated iodine spike, KBq/gm DEI-131	37	(1.0 μCi/gm)
Preaccident iodine spike, MBq/gm DEI-131	2.2	(60 μCi/gm)
Steam generator in faulted loop		
Initial water mass, kg	1.37E+5	(3.03E5 lb)
Primary to secondary leak rate, L/d	567.8	(150 gpd)
Iodine partition coefficient		1.0
Steam generator in intact loop		
Primary to secondary leak rate, L/d	567.8	(150 gpd)
Iodine partition coefficient		1.0
Steam released, kg		
0 to 2 hr	1.37E+5	(3.0335E5 lb)
2 to 8 hr	5.56E+3	(1.225E4 lb)
Ratio of iodine release rate from fuel during iodine spike to that during steady-state operation	500	
Reactor primary coolant mass, kg	1.74E+5	(3.84E+5 lb)
Duration of accident, hr	72	
Atmospheric dispersion values, sec/m^3		
EAB		
0 to 2 hours	5.1E-4	
LPZ		
0 to 8 hours	2.2E-4	
8 to 24 hours	1.6E-4	
1 to 4 days	1.0E-4	
Control room analysis parameters	Table 15.3.9	

Table 15.3-3 Assumptions Used to Evaluate the Radiological Consequences of the Reactor Coolant Pump Shaft Seizure Accident (Locked Rotor)

Parameter	Value	
Power level, MWt	3468	
Fraction of fuel rods failed	0.10	
Fraction of core activity in failed fuel rod gap		
I-131	0.08	
Kr-85	0.10	
Other iodines and noble gases	0.05	
Alkali metals	0.12	
Reactor primary coolant iodine concentrations		
Preaccident iodine spike, MBq/gm DEI-131	2.2	(60 μCi/gm)
Secondary coolant mass, kg	2.75E+5	(6.06E5 lb)
Primary to secondary leak rate, kg/hr	47.3	(104.3 lb/hr)
Iodine partition coefficient	0.01	
Alkali metal partition coefficient	0.001	
Steam released, kg		
0 to 1.5 hr	2.94E+5	(6.48E+5 lb)
Leak flashing fraction		
0 to 60 min	0.04	
>60 min	0	
Reactor primary coolant mass, kg	1.68E+5	(3.7E+5 lb)
Duration of accident, hr	1.5	
Atmospheric dispersion values, sec/m^3		
EAB		
0 to 2 hours	5.1E-4	
LPZ		
0 to 8 hours	2.2E-4	
Control room analysis parameters	Table 15.3.9	

Table 15.3-4 (Sheet 1 of 2) Assumptions Used to Evaluate the Radiological Consequences of the Rod Ejection Accident

Parameter	Value	
Power level, MWt	3468	
Peaking factor	1.65	
Fraction of fuel rods failed	0.1	
Fraction of fission-product inventory released to coolant from perforated fuel rods		
Iodines and noble gases	0.1	
Alkali metals	0.12	
Fraction of fuel rods melted	0.0025	
Fraction of fission-product inventory released to coolant from melted fuel rods		
Iodines and alkali metals	0.5	
Noble gases	1.0	
Initial reactor coolant iodine activity, MBq/gm DEI-131	2.2	(60 μCi/gm)
Reactor coolant mass, kg	1.68E+5	(3.7E5 lb)
Duration of accident, days	30	
Iodine chemical form fractions		
Organic	0.0015	
Elemental	0.0485	
Particulate	0.95	
Secondary system release path		
Primary to secondary leak, kg/hr	47.31	(104.3 lb/hr)
Leak flashing fraction	0.04	
Secondary coolant mass, kg	2.75E+5	(6.06E+5 lb)
Duration of steam release from secondary system, sec	1800	
Steam released from secondary system, kg	4.9E+4	(1.08E+5 lb)
Partition coefficient in steam generators		
Iodine	0.01	
Alkali metals	0.001	

Table 15.3-4 (Sheet 2 of 2) Assumptions Used to Evaluate the Radiological Consequences of the Control Rod Ejection Accident

Parameter	Value
Containment leakage release path	
Containment leak rate, % per day	
0 to 24 hr	0.10
>24 hr	0.05
Airborne activity removal coefficients, hr^{-1}	
Elemental iodine	1.7
Organic iodine	0
Particulate iodine or alkali metals	0.1
Decontamination factor limit for elemental iodine removal	200
Time to reach decontamination factor limit, hr	3.1
Atmospheric dispersion values, sec/m^3	
EAB	
0 to 2 hours	5.1E-4
LPZ	
0 to 8 hours	2.2E-4
8 to 24 hours	1.6E-4
1 to 4 days	1.0E-4
4 to 30 days	8.0E-5
Control room analysis parameters	Table 15.3.9

Table 15.3-5 Assumptions Used to Evaluate the Radiological Consequences of the Small Line Break Outside Containment Accident

Parameter	Value	
Power level, MWt	3468	
Reactor primary coolant iodine concentrations		
Accident-initiated iodine spike, KBq/gm DEI-131	37	(1.0 μCi/gm)
Preaccident iodine spike, MBq/gm DEI-131	2.2	(60 μCi/gm)
Ratio of iodine release rate from fuel during iodine spike to that during steady-state operation	500	
Reactor coolant mass, kg	1.68E+5	(3.7E+5 lb)
Duration of accident, min	30	
Sample line break flow, L/m	492.1	(130 gpm)
Fraction of reactor coolant flashing	0.41	
Atmospheric dispersion values, sec/m^3		
EAB		
0 to 2 hours	5.1E-4	
LPZ		
0 to 8 hours	2.2E-4	
Control room analysis parameters	Table 15.3.9	

Table 15.3-6 Assumptions Used to Evaluate the Radiological Consequences of the Steam Generator Tube Rupture Accident

Parameter	Value	
Power level, MWt	3468	
Reactor primary coolant iodine concentrations		
Accident-initiated iodine spike, KBq/gm DEI-131	37	(1.0 μCi/gm)
Preaccident iodine spike, MBq/gm DEI-131	2.2	(60 μCi/gm)
Steam generator in faulted loop		
Initial water mass, kg	1.37E+5	(3.03E5 lb)
Primary to secondary leak rate, L/d	567.8	(150 gpd)
Iodine partition coefficient for breakflow	1	
Iodine partition coefficient for secondary steaming	0.01	
Alkali metal partition coefficient	0.001	
Steam generator in intact loop		
Primary to secondary leak rate, L/d	567.8	(150 gpd)
Iodine partition coefficient	0.01	
Alkali metal partition coefficient	0.001	
Steam released, kg		
0 to 2 hr	1.65E+5	(3.64E+5 lb)
2 to 8 hr	3.24E+5	(7.15E+5 lb)
Ratio of iodine release rate from fuel during iodine spike to that during steady-state operation	335	
Reactor primary coolant mass, kg	1.74E+5	(3.84E+5 lb)
Duration of accident, hr	13.19	
Atmospheric dispersion values, sec/m^3		
EAB		
0 to 2 hours	5.1E-4	
LPZ		
0 to 8 hours	2.2E-4	
8 to 24 hours	1.6E-4	
1 to 4 days	1.0E-4	
4 to 30 days	8.0E-5	
Control room analysis parameters	Table 15.3.9	

Table 15.3-7 Assumptions Used to Evaluate the Radiological Consequences of the Loss-of-Coolant Accident

Parameter		Value
Power level, MWt		3468
Core activity released to the containment atmosphere, fraction		
Nuclide Group	Gap Release (0–0.5 hr)	In-vessel Release (0.5–1.3 hr)
Noble gases	0.05	0.95
Iodines	0.05	0.35
Alkali metals	0.05	0.25
Tellurium group		0.05
Strontium and barium		0.02
Noble metals		0.0025
Cerium group		0.0005
Lanthanide group		0.0002
Iodine chemical form fractions		
Organic		0.0015
Elemental		0.0485
Particulate		0.95
Primary containment leakage, weight percent/day		
0 to 24 hours		0.1
>24 hours		0.05
Primary containment free volume, m^3		5.83E+4 (2.06E6 ft^3)
Elemental iodine deposition removal coefficient, hr^{-1}		1.7
Decontamination factor limit for elemental iodine removal		200
Removal coefficients for particulates		Table 15.3-8
Accident duration, days		30
Atmospheric dispersion values, sec/m^3		
EAB		
0 to 2 hours		5.1E-4
LPZ		
0 to 8 hours		2.2E-4
8 to 24 hours		1.6E-4
1 to 4 days		1.0E-4
4 to 30 days		8.0E-5
Control room analysis parameters		Table 15.3.9

Table 15.3-8 Aerosol Removal Rates Used by Staff to Evaluate Loss-of-Coolant Accident

Time Post Release (hours)	Removal Rates ($hour^{-1}$)
0.00 to 0.37	0.945
0.37 to 0.87	0.540
0.87 to 1.37	0.430
1.37 to 1.87	0.600
1.87 to 2.37	0.855
2.37 to 2.87	0.585
2.87 to 3.37	0.575
3.37 to 6.87	0.480
6.87 to 24.00	0.430

Table 15.3-9 (Sheet 1 of 2) Assumptions Used to Evaluate the Radiological Consequences to Control Room Operators Following a Design-Basis Accident

Parameter	Value	
Accident release modeling		
Main steamline break	Table 15.3-2	
Locked rotor accident	Table 15.3-3	
Rod ejection accident	Table 15.3-4	
Small line break outside containment	Table 15.3-5	
Steam generator tube rupture	Table 15.3-6	
Loss-of-coolant accident	Table 15.3-7	
Fuel-handling accident	Table 15.3-10	
Control room free volume, m^3	1.01E+3	(3.57E+4 ft^3)
Breathing rate of operators in control room for the course of the accident, m^3/sec	3.47E-4	
Atmospheric dispersion values	Table 15.3-9a	
Control room operator occupancy factors		
0 to 24 hr	1.0	
24 to 96 hr	0.6	
96 to 720 hr	0.4	
Control room with emergency habitability system credited		
Initial interval before actuation of emergency habitability system		
Air intake flow, m^3/min	54.5	(1925 cfm)
Intake filter efficiencies	N/A	
Interval with operation of emergency habitability system		
Activity level at which emergency habitability system is actuated, KBg/m^3 of dose equivalent I-131	74	(2.0E-6 Ci/m^3)
Flow from compressed air bottles, m^3/min	1.7	(60 cfm)
Unfiltered inleakage, m^3/min	0.14	(5 cfm)
Bottled air depletion time, hr	72	
Interval after depletion of bottled air supply		
Air intake flow, m^3/min	48.1	(1700 cfm)
Intake filter efficiencies	N/A	
Recirculation flow	N/A	

Table 15.3-9 (Sheet 2 of 2) Assumptions Used to Evaluate the Radiological Consequences to Control Room Operators Following a Design-Basis Accident

Parameter	Value	
Time when compressed air restored, hr	168	
Staff-calculated DBA control room dose results	Table 15.3-1	
Control room and TSC with credit for supplemental air filtration mode of HVAC		
Initial interval before actuation of supplemental air filtration		
Air intake flow, m^3/min	54.5	(1925 cfm)
Intake filter efficiencies	N/A	
Time delay to switch from normal operation to filtration, sec	30	
Filtered air intake flow, m^3/min	24.4	(860 cfm)
Filtered air recirculation flow, m^3/min	77.6	(2740 cfm)
Filter efficiency, %		
Elemental iodine	90	
Organic iodine	90	
Particulates	99	
Unfiltered air inleakage, m^3/min	2.55	(90 cfm)
Staff-calculated TEDE in control room and TSC with credit for supplemental air filtration		
Main steamline break		
Accident-initiated I spiking	28 mSv	(2.8 rem)
Preexisting I spike	4 mSv	(0.4 rem)
Locked rotor		
With feedwater available	4 mSv	(0.4 rem)
Without feedwater available	<1 mSv	(<0.1 rem)
Rod ejection	5 mSv	(0.5 rem)
Small line break	4 mSv	(0.4 rem)
Steam generator tube rupture		
Accident-initiated I spiking	27 mSv	(2.7 rem)
Preexisting I spike	29 mSv	(2.9 rem)
Loss-of-coolant accident	32 mSv	(3.2 rem)
Fuel-handling accident	14 mSv	(1.4 rem)

Table 15.3-9a Atmospheric Dispersion Factors (χ/Q) for Control Room Habitability Accident Dose Analysis

χ/Q (sec/m³) at Control Room HVAC Intake for Identified Release Points

	Plant Vent or PCS Air Diffuser	Ground Level Containment Release	PORV and Safety-Valve Releases	Steamline Break Releases	Fuel-Handling Area
0–2 hr	2.2E-3	2.2E-3	2.0E-2	2.4E-2	6.0E-3
2–8 hr	1.4E-3	1.4E-3	1.8E-2	2.0E-2	4.0E-3
8–24 hr	6.0E-4	6.0E-4	7.0E-3	7.5E-3	2.0E-3
24–96 hr	4.5E-4	4.5E-4	5.0E-3	5.5E-3	1.5E-3
96–720 hr	3.6E-4	3.6E-4	4.5E-3	5.0E-3	1.0E-3

χ/Q (sec/m³) at Control Room Door for Identified Release Points

	Plant Vent or PCS Air Diffuser	Ground Level Containment Release	PORV and Safety-Valve Releases	Steamline Break Releases	Fuel-Handling Area
0–2 hr	6.6E-4	6.6E-4	4.0E-3	4.0E-3	6.0E-3
2–8 hr	4.8E-4	4.8E-4	3.2E-3	3.2E-3	4.0E-3
8–24 hr	2.1E-4	2.1E-4	1.2E-3	1.2E-3	2.0E-3
24–96 hr	1.5E-4	1.5E-4	1.0E-3	1.0E-3	1.5E-3
96–720 hr	1.3E-4	1.3E-4	8.0E-4	8.0E-4	1.0E-3

Table 15.3-10 Assumptions Used to Evaluate the Radiological Consequences of a Fuel-Handling Accident

Parameter	Value
Power level, MWt	3468
Peaking factor	1.65
Number of fuel assemblies in core	157
Number of assemblies damaged	1
Reactor shutdown time before fuel movement, hr	24
Core fractions released from damaged rods	
I-131	0.08
Other iodines	0.05
Kr-85	0.10
Other noble gases	0.05
Iodine chemical form fractions	
Organic	0.0015
Elemental	0.0485
Particulate	0.95
Iodine effective pool decontamination factor	200
Duration of accident, hr	2
Atmospheric dispersion values, sec/m^3	
EAB	
0 to 2 hours	5.1E-4
LPZ	
0 to 8 hours	2.2E-4
Control room analysis parameters	Table 15.3.9

Table 15.3-11 Assumptions Used to Evaluate the Radiological Consequences of Spent Fuel Pool Boiling

Parameter	Value	
Initial activity in spent fuel pool, Bq		
I-131	1.18E+11	(3.18 Ci)
Other nuclides	None modeled	
Fuel stored in spent fuel pool from 10 years of operation (includes 68 assemblies from a recent refueling)		
Amount of I-131 diffusing into pool over 30-day period, Bq	7.18E+10	(1.94 Ci)
Initial pool water temperature, °C	49	(120 °F)
Time to initiate pool boiling, hr	8.8	
Steaming rate, kg/hr		
8.8–24 hr	7348	(16,200 lb/hr)
24–48 hr	7257	(16,000 lb/hr)
48–72 hr	7121	(15,700 lb/hr)
72–88 hr	6994	(15,420 lb/hr)
88–120 hr	6917	(15,250 lb/hr)
120–168 hr	6772	(14,930 lb/hr)
≥168 hr	6577	(14,500 lb/hr)
Iodine partition coefficient	0.01	
Atmospheric dispersion values, sec/m^3		
LPZ		
8 to 24 hours	1.6E-4	
1 to 4 days	1.0E-4	
4 to 30 days	8.0E-5	
Offsite breathing rate, m^3/sec		
8 to 24 hr	1.8E-4	
>24 hr	2.3E-4	
Control room analysis parameters	Table 15.3.9	

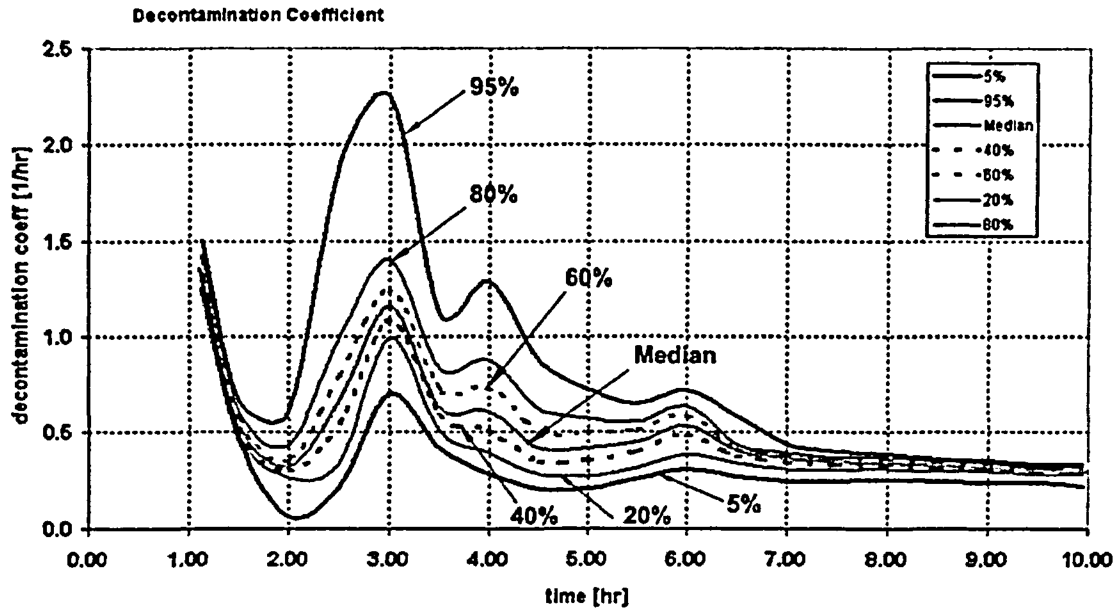

Figure 15.3.6-1 Uncertainty Bands for Aerosol Removal Coefficients

Time hr	5%	95%	40%	60%	45%	55%	20%	80%	mean	median
1.13	1.26	1.51	1.32	1.40	1.33	1.38	1.30	1.43	1.36	1.35
1.50	0.46	0.67	0.51	0.57	0.52	0.56	0.49	0.61	0.55	0.54
2.00	0.07	0.60	0.30	0.36	0.31	0.35	0.27	0.43	0.34	0.32
2.50	0.21	1.89	0.54	0.80	0.57	0.74	0.34	1.00	0.71	0.66
3.00	0.70	2.25	1.10	1.25	1.12	1.22	1.00	1.40	1.21	1.17
3.50	0.42	1.12	0.58	0.73	0.60	0.70	0.51	0.84	0.67	0.63
4.00	0.28	1.29	0.51	0.74	0.53	0.69	0.39	0.88	0.64	0.61
4.50	0.20	0.88	0.36	0.50	0.37	0.49	0.28	0.63	0.45	0.42
5.00	0.20	0.73	0.35	0.50	0.37	0.48	0.27	0.57	0.43	0.42
5.50	0.26	0.65	0.40	0.52	0.41	0.50	0.31	0.56	0.45	0.45
6.00	0.31	0.72	0.49	0.59	0.51	0.59	0.39	0.63	0.53	0.54
6.50	0.27	0.58	0.38	0.42	0.39	0.41	0.34	0.44	0.40	0.40
7.00	0.24	0.44	0.34	0.38	0.35	0.37	0.31	0.39	0.36	0.37
7.50	0.24	0.40	0.33	0.36	0.33	0.35	0.30	0.37	0.34	0.35
8.00	0.25	0.39	0.33	0.35	0.33	0.35	0.31	0.37	0.34	0.34
8.50	0.25	0.36	0.31	0.34	0.32	0.33	0.30	0.35	0.32	0.33
9.00	0.24	0.36	0.31	0.33	0.31	0.33	0.29	0.34	0.32	0.32
9.50	0.24	0.33	0.29	0.31	0.29	0.31	0.28	0.32	0.30	0.30
9.95	0.22	0.33	0.29	0.31	0.29	0.30	0.27	0.32	0.29	0.30

Table 15.3.6-1 Aerosol Removal Coefficients as Calculated by Uncertainty Analysis (hr^{-1})

16. TECHNICAL SPECIFICATIONS

16.1 Introduction

The AP1000 technical specifications (TS) were modeled after Revision 2 of NUREG-1431, "Standard Technical Specifications: Westinghouse Plants" (STS). These STS were developed from the results of the TS improvement program, in accordance with SECY-93-067, "Final Policy Statement on TS Improvements for Nuclear Power Reactors," published on July 22, 1993, and Title 10, Section 50.36, of the Code of Federal Regulations (10 CFR 50.36), "Technical Specifications," as amended July 19, 1995. The applicant states that the AP1000 TS comply with 10 CFR 50.36(c)(2)(ii), which requires the TS to include a limiting condition for operation for each item meeting one or more of the following four criteria:

- Criterion 1—installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary

- Criterion 2—a process variable, design feature, or operating restriction that is an initial condition of a design-basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier

- Criterion 3—a structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design-basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier

- Criterion 4—a structure, system, or component which operating experience or a probabilistic safety assessment has shown to be significant to public health and safety

The review of the AP1000 TS by the staff of the U.S. Nuclear Regulatory Commission (NRC) concentrated on the differences between that document and the STS. These differences result from the new passive systems design, structural differences from existing systems, and the advanced microprocessor-based instrumentation and control (I&C) system, as well as shutdown operations.

After its review, the staff forwarded its comments on the AP1000 TS to the applicant for resolution and incorporation into the final TS. The final AP1000 TS, included in Design Control Document (DCD) Tier 2, Section 16.1, provides resolution of the issues raised by the staff and are certified to be accurate by the applicant.

16.2 Evaluation

The staff evaluated the AP1000 TS to confirm that they will preserve the validity of the plant design, as described in the AP1000 DCD, by ensuring that the plant will be operated (1) within the required conditions bounded by the AP1000 DCD, and (2) with operable equipment that is essential to prevent accidents and to mitigate the consequences of accidents postulated in the AP1000 DCD. The staff also assessed the AP1000 TS to confirm that a limiting condition for operation (LCO) was established for any aspect of the design that met the criteria in 10 CFR 50.36(c)(2)(ii).

The AP1000 design includes safety systems that are both innovative and simplified. It employs passive safety-related systems that rely on gravity and natural processes, such as convection, evaporation, and condensation. Although the staff asked the applicant to model the AP1000 TS after NUREG-1431 to the maximum extent practical, it was necessary to develop TS beyond those in the STS to account for the advanced passive design features of the AP1000. However, in most cases, the AP1000 system design functions are similar to those of existing pressurized-water reactors (PWRs), even though the components and systems are new. The staff also requested that the applicant model the AP1000 TS after the equivalent STS safety functions. In those cases in which the staff believed deviation from the STS was appropriate to account for AP1000 design features, the required action completion times and surveillance requirement frequencies associated with the LCOs were maintained consistent with the STS provisions for the equivalent safety function.

In some instances, detailed design information, equipment selection, allowable values, or other information are needed to establish the information to be included in the TS. Locations for the addition of this information are signified by brackets to indicate that the combined license (COL) applicant must provide plant-specific values or alternative text. This is COL Action Item 16.2-1.

A comparison of the AP1000 TS with the STS, as well as an evaluation of the differences, is provided in the following sections.

16.2.1 AP1000 TS Section 1.0, "Use and Application"

Section 1.1 of the AP1000 TS provides definitions that correspond to those given in the STS. These definitions are acceptable to the staff because they are consistent with the STS and the AP1000 design features.

In addition to the STS definition of Dose Equivalent I-131, Section 1.1 of the AP1000 TS also includes a definition for Dose Equivalent Xe-133 not found in the STS. The source documents for the dose conversion factors for these two quantities differ from the STS, but are acceptable because they are consistent with the AP1000 dose analysis, which uses the total effective dose equivalent methodology, and Regulatory Guide (RG) 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors." AP1000 TS 3.4.10, "RCS Specific Activity," places limits on these two quantities, in accordance with Criterion 2 of 10 CFR 50.36(c)(2)(ii). This will ensure that the doses resulting from a design-basis accident (DBA), such as a steam generator tube rupture (SGTR), will be within the bounding values of the AP1000 accident analysis. Therefore, specifying a definition for Dose Equivalent Xe-133 is appropriate and is acceptable as proposed.

Section 1.1 of the AP1000 TS omits STS definitions for $\bar{E}$—average disintegration energy, master relay test, and slave relay test; the AP1000 TS do not use these definitions.

Section 1.2 of the AP1000 TS (logical connectors), Section 1.3 (required action completion time rules), and Section 1.4 (surveillance requirement frequency rules) are consistent with the STS and are therefore acceptable.

16.2.2 AP1000 TS Section 2.0, "Safety Limits"

Section 2.0 of the AP1000 TS outlines the safety limit specifications. These are consistent with the STS and are therefore acceptable.

16.2.3 AP1000 TS Section 3.0, "Limiting Condition for Operation Applicability and Surveillance Requirement Applicability"

Section 3.0 of the AP1000 TS governs the general application of the LCOs and surveillance requirements (SRs). The specifications provided in Section 3.0, which correspond to the STS (LCOs 3.0.1 through 3.0.7 and SRs 3.0.1 through 3.0.4) are acceptable to the staff because they are consistent with the STS.

In addition, Section 3.0 includes LCO 3.0.8 to specify appropriate remedial actions in the event that an applicable shutdown LCO, and associated action requirements, cannot be met in Modes 5 and 6. This specification is a consequence of the AP1000 TS containing LCOs applicable during shutdown conditions that are in addition to those in the STS. The AP1000 TS LCOs 3.0.8 and 3.0.3 apply under similar conditions (i.e., when the action requirements of an LCO are not met and no other action is specified, or when none of the action requirements of an LCO address the plant condition). However, while LCO 3.0.3 only applies during operating conditions (Modes 1, 2, 3, and 4), LCO 3.0.8 also applies during shutdown conditions (Modes 5 and 6). This specification conforms to the format and usage rules of the STS and is acceptable because it specifies remedial actions that will maintain the plant in a safe condition in the event that a shutdown LCO is not met and the associated action requirements of the LCO are either not met or no associated action requirements are specified.

16.2.4 AP1000 TS Section 3.1, "Reactivity Control Systems"

Section 3.1 of the AP1000 TS governs reactivity control systems. The specifications in Section 3.1 which correspond to those given in STS 3.1.1 through 3.1.8 are acceptable to the staff because they are consistent with the STS.

In addition, Section 3.1 includes a specification, TS 3.1.9, to prevent an inadvertent reactor coolant system (RCS) boron dilution event. This TS requires two operable isolation valves capable of isolating the chemical and volume control system (CVS) from the demineralized water storage tank. The isolation condition required by TS 3.1.9 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Further, the new demineralized water isolation valve specification conforms to the format and usage rules of the STS and is acceptable because it will prevent an inadvertent RCS boron dilution event.

16.2.5 AP1000 TS Section 3.2, "Power Distribution Limits"

Section 3.2 of the AP1000 TS governs core power distribution limits. The specifications in Section 3.2 which correspond to those given in STS 3.2.1 through 3.2.4 are acceptable to the staff because they are consistent with the STS.

In addition, Section 3.2 includes a specification, TS 3.2.5, to govern the use of the on-line power distribution monitoring system (OPDMS). This system continuously monitors the power distribution parameters within the core via fixed, in-core detectors. It actuates alarms to alert control room staff to take timely corrective action when an OPDMS-monitored power distribution parameter is approaching the specified limit. The inclusion of the OPDMS in the AP1000 TS satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). This new specification conforms to the format and usage rules of the STS and is acceptable because it will prevent the core power distribution from exceeding the limits on initial conditions assumed in the safety analyses.

16.2.6 AP1000 TS Section 3.3, "Instrumentation"

Section 3.3 of the AP1000 TS contains significant differences from the I&C provisions in the STS. The use of micro-processor (or digital)-based I&C systems in the AP1000 design is one source of the differences between the AP1000 TS and the STS. Another source of difference is the non-safety-related designation of a number of the active systems in the AP1000 design that correspond to safety-related systems in the STS. The applicant determined that the four criteria of 10 CFR 50.36(c)(2)(ii) do not require I&C TS LCOs for such non-safety-related systems.

Section 3.3 of the AP1000 TS contains four I&C specifications based on the corresponding specifications in the STS. These include TS 3.3.1 for the reactor trip system (RTS), TS 3.3.2 for the engineered safety features actuation system (ESFAS), TS 3.3.3 for the postaccident monitoring system (PAM), and TS 3.3.4 for the remote shutdown workstation system instrumentation. However, to account for the AP1000 design differences, the I&C functions contained in these four specifications vary significantly from the equivalent functions described in the STS, including STS 3.3.1 for the RTS, STS 3.3.2 for the ESFAS, STS 3.3.3 for the postaccident monitoring system, STS 3.3.4 for remote shutdown workstation system, STS 3.3.6 for containment purge and exhaust isolation, STS 3.3.7 for control room emergency filtration system actuation, and STS 3.3.9 for the boron dilution protection system instrumentation.

Section 3.3 of the AP1000 TS omits STS specifications for loss of power diesel generator start (STS 3.3.5) and fuel building air cleaning system actuation instrumentation (STS 3.3.8) because the associated systems are not safety-related in the AP1000 design. In addition, the I&C functions for containment purge and exhaust isolation, control room emergency filtration system actuation, and the boron dilution protection system are not presented in separate specifications. Rather, AP1000 TS 3.3.2 for ESFAS instrumentation includes these functions.

The staff requested that the applicant justify the use of WCAP-10271-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," Supplement 2, Revision 1, which is applicable to analog instrumentation systems, as a basis for certain required action completion times for the digitally-based instrumentation covered by TS 3.3.1 and TS 3.3.2. The applicant responded by bracketing the affected values, thus indicating that the final determination and justification of these time limits is the responsibility of the COL applicant. The staff finds this approach acceptable because the COL applicant would have to make such determinations and justifications, regardless of the applicability of WCAP-10271-P-A. The staff identifies this as part of COL Action Item 16.2-1.

Section 3.3 of the AP 1000 TS regarding safety-related instrumentation systems implements modified versions of the STS associated with the equivalent safety functions. These specifications conform to the format and usage rules of the STS and are functionally equivalent to the STS. As explained previously, the staff agrees that the AP1000 design differences justify not specifying LCOs for the STS instrumentation system functions noted above. The AP1000 TS 3.3.1, 3.3.2, 3.3.3, and 3.3.4 are acceptable because they will ensure that the specified instrumentation systems are capable of performing their intended safety functions, as assumed in the safety analyses, in the event of a DBA or transient.

Section 3.3 also includes a new specification, TS 3.3.5, to govern the diverse actuation system (DAS) manual controls. The DAS is a non-safety-related system that provides an anticipated transient without scram (ATWS) mitigation function (reactor trip, turbine trip, and passive residual heat removal heat exchanger actuation), as well as an ESFAS function for accident mitigation. The DAS automatic functions use equipment that is diverse from the safety-related I&C system (the protection and safety monitoring System (PMS)) from sensor output to the final actuated device. These functions automatically initiate a reactor trip and actuate designated safety-related equipment. The AP1000 DAS automatic and manual instrumentation functions are not credited in the DCD Tier 2, Chapter 15, safety analyses. Consequently, the DAS functions do not meet Criterion 1, 2, or 3 of 10 CFR 50.36(c)(2)(ii). In addition, the applicant determined that the automatic DAS functions do not meet Criterion 4.

However, as described in WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Non-Safety-Related Systems Process," Revision 1, dated April 2003, the applicant determined that the regulatory treatment of non-safety systems (RTNSS) analysis for the automatic functions of the DAS demonstrates that they are important because they compensate for the accident mitigation uncertainty identified in the probabilistic risk assessment (PRA). In other words, the automatic functions of the DAS provide margin in the PRA sensitivity analysis (see Chapter 22 of this report). This analysis assumed no credit for non-safety-related systems, structures and components (SSCs) to mitigate at-power and shutdown events. However, the analysis did consider non-safety-related SSCs in the calculation of initiating event frequencies. Thus, DCD Tier 2, Section 16.3, establishes investment protection short-term availability controls (as defined in Section 22.5.9 of this report) for the automatic DAS ATWS mitigation and DAS ESFAS instrumentation. Should a COL be issued, the short-term availability controls would be maintained in a licensee-controlled document, as discussed in Section 22.5.9 of this report.

The DAS manual controls provide non-Class 1E backup controls in case of a common-mode failure of the PMS automatic and manual actuations, as evaluated in the AP1000 PRA. The applicant determined that crediting the DAS manual controls was necessary to meet the large release frequency safety goal identified in the focused PRA (see Sections 22.3.3 and 22.5.8 of this report). From this, the applicant concluded that the DAS manual controls satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii), and accordingly proposed TS 3.3.5 to comply with 10 CFR 50.36. In the event that one or more DAS manual control functions are inoperable for 30 days, the associated proposed action requirements specify more frequent performance of the RTS trip actuating device operational test for the reactor trip breakers and the ESFAS actuation logic test for the ESFAS instrumentation backed up by the DAS, as appropriate. These, and other associated action requirements, are acceptable because they provide a level of protection equivalent to that of the associated LCO. This acceptance is related to the resolution of Open Item 19.1.10.1-3 to confirm proper use of PRA results in determining the level of regulatory oversight (e.g., required action completion time and surveillance frequency). The NRC staff has determined that Open Item 19.1.10.1-3 is resolved because the applicant has properly used AP1000 PRA results. Therefore, the staff finds that the proposed TS 3.3.5, which conforms to the format and usage rules of the STS, is acceptable because it adequately compensates for the risk of a common-cause failure of the PMS.

16.2.7 AP1000 TS Section 3.4, "Reactor Coolant System"

The AP1000 RCS specifications correspond to those in the STS, as follows:

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
3.4.1	3.4.1	RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling Limits (*same)
3.4.2	3.4.2	RCS Minimum Temperature for Criticality (*same)
3.4.3	3.4.3	RCS Pressure and Temperature (P/T) Limits (*same)
3.4.4*	3.4.4	RCS Loops (*RCS Loops - Modes 1 and 2)
3.4.5*	3.4.4	RCS Loops (*RCS Loops - Mode 3)
3.4.6*	3.4.4	RCS Loops (*RCS Loops - Mode 4)
3.4.7*	3.4.4	RCS Loops (*RCS Loops - Mode 5, loops filled)
3.4.8*	None	(*RCS Loops - Mode 5, loops not filled)
3.4.9	3.4.5	Pressurizer (*same)
3.4.10	3.4.6	Pressurizer Safety Valves (*same)
3.4.13	3.4.7	RCS Operational Leakage (*same)
None	3.4.8	Minimum RCS Flow
3.4.15	3.4.9	RCS Leakage Detection Instrumentation (*same)
3.4.16	3.4.10	RCS Specific Activity (*same)
None	3.4.11	Automatic Depressurization System (ADS) - Operating
None	3.4.12	ADS - Shutdown, RCS Intact

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
None	3.4.13	ADS - Shutdown, RCS Open
3.4.12*	3.4.14	Low-Temperature Overpressure Protection System (*same)
3.4.14*	3.4.15	RCS Pressure Isolation Valve (PIV) Integrity (*RCS PIV Leakage)
None	3.4.16	Reactor Vessel Head Vent (RVHV)
None	3.4.17	CVS Makeup Isolation Valves
3.4.11*	None	(*Pressurizer Power-Operated Relief Valves (PORVs))
3.4.17*	None	(*RCS Loop Isolation Valves)
3.4.18*	None	(*RCS Isolated Loop Startup (related to loop isolation valve LCO))
3.4.19*	None	(*RCS Loops - Test Exceptions)

AP1000 TS 3.4.7, regarding RCS operational leakage, differs from the STS by specifying an allowable, unidentified leakage of 1.89 liters per minute (lpm) (0.5 gallons per minute (gpm)), which is less than the STS value of 3.79 lpm (1 gpm). This difference is based on the AP1000 leak before break assumptions. AP1000 TS 3.4.9, regarding RCS and main steam leakage detection instrumentation, also differs from the STS to reflect the AP1000 design. These differences are acceptable because they are more restrictive than the STS and they accurately reflect differences in the AP1000 design related to reactor coolant and main steam leakage limitations and detection.

AP1000 TS 3.4.10, regarding RCS specific activity, omits STS SR 3.4.16.3. This surveillance requires, on a 184-day frequency, determining $\bar{E}$, the average disintegration energy, from a sample taken in Mode 1 after a minimum of 2 effective full-power days and 20 days of Mode 1 operation have elapsed since the reactor was last subcritical for less than or equal to 48 hours. Although $\bar{E}$ is not used in the AP1000 TS, the staff requested that the applicant explain why an equivalent surveillance using Dose Equivalent Xe-133 was not proposed. This was Open Item 16.2-1 in the DSER. The applicant adopted STS SR 3.4.16.3 as SR 3.4.10.3 in DCD Tier 2, Chapter 16.1, with the exception that the AP1000 surveillance determines Dose Equivalent Xe-133 instead of $\bar{E}$. This difference is consistent with the AP1000 design radiological consequence analyses and is acceptable. Therefore, Open Item 16.2-1 is resolved.

The AP1000 RCS TS Section contains additional specifications to address (1) minimum RCS flow, (2) the automatic depressurization system (ADS), (3) the reactor vessel head vent (RVHV) system, and (4) the CVS makeup isolation valves, in accordance with Criterion 3 of 10 CFR 50.36(c)(2)(ii). These specifications conform to the format and usage rules of the STS.

The purpose of TS 3.4.8 for minimum RCS flow is to maintain uniform RCS mixing as an initial condition for boron dilution transients. LCO 3.4.8 also specifies conditions for halting and restoring forced circulation in the RCS to ensure that the required shutdown margin and RCS subcooling margin are maintained. It also prevents the thermal transient associated with starting a reactor coolant pump from overpressurizing the RCS at low temperatures. In the event forced circulation is lost, the action requirements will ensure maintenance of the required shutdown margin. The requirements of this specification will maintain the validity of the analysis of the design basis RCS boron dilution transient. Therefore, TS 3.4.8 is acceptable.

The purpose of the ADS, which consists of four different stages of depressurization valves, is to depressurize the RCS to allow gravity injection of water from the in-containment refueling water storage tank (IRWST) or from the containment sump for long-term recirculation cooling. The proposed ADS required action 72-hour completion times are consistent with the repair time allowed for a loss of redundancy in the STS. Further, the proposed ADS SRs are adequate to assure operability of the ADS flow paths required by the associated LCOs. Thus, TS 3.4.11 and 3.4.12 will ensure that depressurization of the RCS will occur as assumed in the safety analysis in the event of a DBA (e.g., a loss-of-coolant accident (LOCA)). While the plant is shut down with the RCS open, TS 3.4.13 will ensure that sufficient vent area is available to support IRWST injection and containment recirculation to mitigate events in which core cooling, RCS makeup, or boration is needed. Therefore, the proposed ADS system specifications are acceptable.

The purpose of TS 3.4.16 is to ensure operability of the manually operated RVHVs so that the control room staff can open them to prevent overfilling of the pressurizer during RCS coolant-addition transients. Each of the two vent flow paths is capable of preventing overfill of the pressurizer. The 72-hour completion time for restoring one inoperable RCS vent flow path is consistent with the repair time allowed for a loss of redundancy in the STS. With both flow paths inoperable, the action requirements permit 6 hours to restore one flow path to operable status. This is acceptable, according to the proposed TS Bases, because of the conservatism in the coolant-addition transient analysis; the applicant has performed a more realistic analysis that demonstrates that overfilling will not occur. Periodic valve stroke-open surveillance, which is required by the inservice testing program, provides assurance of operability of the four vent valves. The RVHV specification will ensure that the RCS vent system will be available to the control room staff to prevent a coolant-addition transient from overfilling the pressurizer. Therefore, TS 3.4.16 is acceptable.

The purpose of TS 3.4.17 is to ensure operability of the redundant CVS makeup isolation valves to automatically prevent overfilling of the pressurizer during non-LOCA transients, and overfilling of the steam generators during SGTR accidents. The accident analyses of such events assume that excessive addition of coolant to the RCS from the CVS makeup would increase the associated consequences. The analyses thus assume that the CVS makeup is automatically isolated by a high water level in either the pressurizer or a steam generator. The 72-hour completion time for restoring one inoperable CVS makeup isolation valve is consistent with the repair time allowed for a loss of redundancy in the STS. With both valves inoperable, the makeup line must be isolated in 1 hour. The associated SRs provide assurance that these two isolation valves will automatically shut within the time interval assumed in the pertinent accident and transient analyses. The CVS makeup isolation valve specification will ensure that

RCS makeup will be isolated, as assumed in the accident analyses. Therefore, TS 3.4.17 is acceptable.

Omitting the STS specifications for RCS power-operated relief valves (PORVs) and loop isolation valves is acceptable because these features are not used in the AP1000 design.

The Bases for STS 3.4.19 state that its primary purpose is to provide an exception to LCO 3.4.4, "RCS Loops—Modes 1 and 2," to permit reactor criticality under no flow conditions during certain physics tests, natural circulation demonstration, station blackout, and loss of offsite power to be performed while at low thermal power levels. A COL applicant may adopt this test exception LCO if it plans to conduct these kinds of tests. However, the AP1000 TS need not include this test exception because (1) these tests are not required, and (2) compliance with a test exception LCO is optional, in which case other specifications, such as STS 3.4.4, would apply. In addition, with the application of the other TS, including STS 3.4.4, this test exception LCO is not required by 10 CFR 50.36 because it does not meet any of the four criteria in 10 CFR 50.36(c)(2)(ii). Therefore, it is acceptable to omit a specification corresponding to STS 3.4.19 from the AP1000 TS.

Based on the above, the staff finds the AP1000 TS for the reactor coolant system acceptable.

16.2.8 AP1000 TS Section 3.5, "Passive Core Cooling System"

The AP1000 uses passive core cooling systems (PXS) rather than the pump-driven, active emergency core cooling systems (ECCS) of currently operating plants, upon which STS ECCS specifications are based. The safety-related PXS is designed to perform emergency core cooling and decay heat removal, reactor coolant emergency makeup and boration, and safety injection. The PXS is located inside the containment; it consists of several subsystems and associated components including the passive residual heat removal heat exchanger (PRHR HX) system, core makeup tanks (CMTs), IRWST, ADS, and accumulators. The AP1000 PXS specifications generally correspond to the STS for ECCS, as follows:

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
3.5.1*	3.5.1	Accumulators (*same)
3.5.2*	3.5.2	CMTs - Operating (*ECCS - Operating)
3.5.3*	3.5.3	CMTs - Shutdown, RCS Intact (*ECCS - Shutdown)
3.7.5*	3.5.4	PRHR HX - Operating (*Auxiliary Feedwater)
None	3.5.5	PRHR HX - Shutdown, RCS Intact
3.5.4*	3.5.6	IRWST - Operating (*RWST)
None	3.5.7	IRWST - Shutdown, Mode 5

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
None	3.5.8	IRWST - Shutdown, Mode 6
3.5.5*	None	(*Seal Injection Flow)
3.5.6*	None	(*Boron Injection Tank)

The PXS accumulators (1) supply water to the reactor vessel during the blowdown and refill phases of a large-break LOCA, (2) provide RCS makeup for a small-break LOCA, and (3) provide RCS boration for steam line breaks. These functions are essentially the same functions that the ECCS accumulators, which are also passive features, perform for currently operating Westinghouse PWRs. Thus, the proposed AP1000 TS 3.5.1 is very similar to STS 3.5.1. Other than appropriate design-based differences in SR acceptance criteria, AP1000 TS 3.5.1 specifies an 8-hour restoration required action completion time for the condition of one accumulator being inoperable for reasons other than boron concentration outside the specified limits. For this condition, the required action completion time is less restrictive than the 1-hour completion time found in the STS. The associated Bases for this completion time state that with one accumulator inoperable, the remaining accumulator is capable of providing the required safety function, except for one low-probability event (i.e., a large, cold-leg LOCA). The Bases also state that the incremental conditional core damage probability (ICCDP) for the 8-hour completion time is more than a factor of 10 less than the value indicated to have a small impact on plant risk (RG 1.177 gives this as an ICCDP value of 1E-7). This completion time is therefore acceptable. This acceptance is related to the resolution of Open Item 19.1.10.1-3 to confirm proper use of the PRA results. The NRC staff determined that Open Item 19.1.10.1-3 is resolved because the applicant had properly used AP1000 PRA results. Based on the above, TS 3.5.1 is, therefore, acceptable.

The CMTs are connected to and maintained within the RCS pressure boundary. This design allows the tanks to supply safety injection cooling and boration to the reactor via natural circulation and gravity injection at any RCS pressure. Thus, the CMTs are a passive means of supplying high-pressure safety injection in the AP1000 design.

The passive residual heat removal (PRHR) system transfers decay heat to the IRWST via natural circulation from the RCS whenever forced circulation cooling of the RCS is not available from the steam generators. The PRHR system provides decay heat removal for mitigation of non-LOCA events. The operation of the PRHR is functionally equivalent to the decay heat removal provided by the auxiliary feedwater system in currently operating Westinghouse PWRs.

The IRWST provides low-head safety injection cooling and boration via gravity injection through redundant direct vessel injection (DVI) flow paths after the RCS has been depressurized by the ADS (TS 3.4.11, 3.4.12, and 3.4.13) or an RCS break. Each IRWST DVI flow path contains redundant actuation valves, in parallel flow paths, so that the failure of one actuation valve to open will not prevent injection from the IRWST in the event of a break in the opposite DVI flow path. Operability of the IRWST also requires operability of the redundant containment sump recirculation flow paths to support long-term cooling of the core.

The TS action requirements for the CMT, PRHR, and IRWST PXS subsystems allow 72 hours for loss of a redundancy in one DVI flow path for each subsystem. This completion time is consistent with STS 3.5.2; however, the TS Bases for the PXS LCOs seem to indicate that only one subsystem at a time is affected. The AP1000 TS do not identify what the appropriate actions are in the event that the plant does not meet two or more PXS specifications (e.g., TS 3.5.1, 3.5.2, 3.5.4, and 3.5.6) concurrently. The TS Bases for the PXS LCOs also seem to indicate that DBA assumptions regarding ECCS functions may not be met in such cases. Pending clarification of the TS Bases, the staff's review of the PXS TS action requirements was considered incomplete. This was Open Item 16.2-2 in the DSER.

In a letter dated December 12, 2003, the applicant proposed several changes to the PXS specifications to resolve Open Item 16.2-2. The applicant determined that certain combinations of inoperable PXS subsystems, for which the proposed PXS TS action requirements would not require an immediate unit shutdown, may prevent adequate safety injection in response to a DVI line small-break LOCA. These combinations involve the following proposed AP1000 PXS TS actions conditions:

<u>Condition 3.5.1.B</u>

One accumulator inoperable for reasons other than Condition 3.5.1.A (boron concentration outside limits).

This actions condition corresponds to an accumulator that is inoperable due to one or more of the following reasons:

- nitrogen pressure not within limits
- water volume not within limits
- outlet isolation valve closed
- outlet isolation valve closed and will not open
- power not removed from outlet isolation valve operator

<u>Condition 3.5.2.C</u>

Two CMTs inoperable due to water temperature or boron concentration not within limits.

<u>Condition 3.5.2.E</u>

One CMT inoperable for reasons other than:

- Condition 3.5.2.A (one CMT outlet isolation valve inoperable (a redundant normally closed valve will not open));

- Condition 3.5.2.B (one or more parameters (water temperature, boron concentration) not within limits);
- Condition 3.5.2.C; or
- Condition 3.5.2.D (presence of noncondensible gases in the high point vent).

Actions Condition 3.5.2.E corresponds to a CMT that is inoperable due to one or more of the following reasons:

- both outlet isolation valves are inoperable (the normally closed valves will not open)
- the normally open return isolation valve is closed
- the normally open return isolation valve is closed and will not open
- water volume less than limit

The applicant proposed an additional 1-hour completion time to exit each of these action conditions, were another action condition entered concurrently, in the following two combinations: (1) Conditions 3.5.1.B and 3.5.2.C, and (2) Conditions 3.5.1.B and 3.5.2.E.

With the unit in either of these combined conditions, the remaining safety injection capability may be less than assumed in the safety analysis for a DVI line, small-break LOCA. In the event of a break in the common DVI line associated with the operable accumulator (and possibly, an operable CMT), the water volume available from the inoperable CMT and inoperable accumulator for safety injection through the associated remaining DVI line would be less than assumed. In the worst case (both injection flow paths isolated), no safety injection would be available from the CMTs and accumulators. Therefore, in either of these combined conditions, the licensee must restore either the accumulator or the CMT to operable status within a short time, or initiate a unit shutdown. The 1-hour completion time permits sufficient time to take action for any problem that can be corrected quickly, such as remotely opening a shut valve or removing power to a valve operator. In such cases, this completion time may allow the unit to avoid an unnecessary shutdown, while also minimizing the time the unit is vulnerable to a DVI line break, if neither the accumulator nor the CMT can be made operable quickly.

The applicant did not propose similar conditional completion times for Condition 3.5.1.A and Conditions 3.5.2.A, 3.5.2.B, 3.5.2.C, and 3.5.2.D because the combination of Condition 3.5.1.A with any one of these CMT action conditions will not result in a significant reduction in the capability of the accumulators and CMTs to perform their safety injection and boration functions. Specifically, assuming no occurrence of an additional single failure concurrent with a DBA:

- Conditions 3.5.1.A and 3.5.2.B and Conditions 3.5.1.A and 3.5.2.C address boron concentration or temperature outside limits. The applicant stated that only slight deviations in these parameters are expected, considering the frequent surveillance to verify proper pressure, volume, and temperature, as well as the control room monitoring instrumentation for these parameters. The applicant stated in its response that an accumulator and a CMT with small deviations in these parameters remain capable of adequately performing their safety injection function. Therefore, these combinations of action conditions do not warrant a more restrictive completion time.

- Conditions 3.5.1.A and 3.5.2.A correspond to an accumulator with only a small deviation outside the boron concentration limits (as just noted) and a CMT that has lost just one redundant safety injection flow path associated with one DVI line. Both the affected accumulator and CMT remain capable of performing their safety functions. Therefore, this combination of action conditions does not warrant a more restrictive completion time.

- Conditions 3.5.1.A and 3.5.2.D correspond to an accumulator with only a small deviation outside the boron concentration limits and a CMT with more than the allowed volume of noncondensible gases in its high point vent collection line. The applicant stated in its response that voiding at the CMT high point has no impact on the performance of the CMT as a backup for the accumulator during a small-break LOCA because significant RCS voiding occurs as a consequence of the event. For other events, the operable redundant CMT will be available. Therefore, this combination of action conditions does not warrant a more restrictive completion time.

The applicant identified no DBA vulnerabilities in combined action conditions between the ADS and IRWST systems, or between these systems and the accumulators or CMTs. The staff concluded that the ADS and IRWST TS action requirements are sufficiently restrictive as currently proposed.

Along with the additional completion times for the accumulator and CMT action requirements, The applicant also proposed appropriate corresponding changes to the Bases, as well as changes to clarify the Bases discussions concerning the conditions in which the unit would be vulnerable to a DVI line, small-break LOCA. Therefore, based on the AP1000 TS changes proposed in the applicant's response, Open Item 16.2-2 is resolved.

In addition, the applicant proposed to relax TS Condition 3.5.6.A to allow a 72-hour completion time to restore an inoperable IRWST injection valve to operable status. This is the same completion time specified to restore an inoperable containment sump recirculation valve. This completion time is appropriate because, even in the event of a DVI line, small-break LOCA in the opposite DVI flow path, the IRWST is still capable of supplying the required low-pressure safety injection through the remaining redundant injection path.

The AP1000 RCS uses canned rotor reactor coolant pumps which have no pump shaft seals. This design feature eliminates the possibility of an associated shaft seal failure LOCA. Consequently, the STS seal injection flow specification is not required for AP1000 and is therefore omitted.

The AP1000 TS omit a specification corresponding to STS 3.5.6 because the AP1000 design does not include a boron injection tank. The boron injection function to maintain the required shutdown margin after an accident is accomplished by the accumulators, CMTs, and IRWST.

The AP1000 specifications for the PXS implement modified versions of the STS for the ECCS. The staff finds that these specifications have been constructed to be essentially equivalent to the STS for the ECCS functions. The staff agrees that for those cases in which a TS corresponding to the STS has not been included, AP1000 design differences provide sufficient justification for such an omission. Therefore, the AP1000 PXS TS are acceptable.

16.2.9 AP1000 TS Section 3.6, "Containment Systems"

The AP1000 TS 3.6.1 through 3.6.5 are essentially identical to the corresponding atmospheric containment STS for containment operability, air locks, isolation valves, pressure, and temperature. The passive containment cooling system (PCS) is the major difference between the AP1000 atmospheric containment design and the atmospheric containment used by many currently operating Westinghouse PWRs. This is reflected in the AP1000 TS Section 3.6 specifications which correspond to the STS as follows:

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
3.6.1*	3.6.1	Containment (*same)
3.6.2*	3.6.2	Containment Air Locks (*same)
3.6.3*	3.6.3	Containment Isolation Valves (*same)
3.6.4A*	3.6.4	Containment Pressure (*same)
3.6.5A*	3.6.5	Containment Air Temperature (*same)
3.6.6A*	3.6.6	PCS - Operating (*Containment Spray and Cooling Systems)
None	3.6.7	PCS - Shutdown
None	3.6.8	Containment Penetrations
3.6.7*	3.6.9	pH Adjustment (*Spray Additive System)
3.6.8*	None	(*Hydrogen Recombiners)
3.6.9*	None	(*Hydrogen Mixing System)
3.6.11*	None	(*Iodine Cleanup System)
3.6.12*	None	(*Vacuum Relief Valves)

The PCS provides the containment safety-grade ultimate heat sink to prevent the containment shell from exceeding its design pressure of 508 kiloPascals (kPa) (59 pounds per square inch gauge (psig)). The PCS uses natural air circulation past the containment shell, enhanced by distribution of cooling water onto the containment shell, to achieve its design objectives. The water is gravity fed from an annular tank with a useable capacity of 2,864 cubic meters (m^3) (756,700 gallons). This tank is designed into the roof on the containment shield building. The tank has sufficient water to provide at least 3 days of cooling. The PCS TS 3.6.6 and 3.6.7 were modeled after STS 3.6.6A for containment cooling.

The AP1000 TS do not contain a containment spray specification because accident mitigation by the AP1000 containment spray system, which is designated as non-safety-related, is not credited in any DBA analysis.

The AP1000 design includes non-safety-related passive autocatalytic recombiners to limit hydrogen buildup inside containment. However, the applicant did not propose a specification similar to STS 3.6.8 for the passive autocatalytic recombiners for design-basis hydrogen control because it expected that such specifications would no longer be required before the staff could complete its review of the AP1000 application.

The NRC has proposed major changes to 10 CFR 50.44, "Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors," and related changes to 10 CFR 50.34, "Contents of Applications; Technical Information," and 10 CFR 52.47, "Contents of Applications," along with the creation of a new rule, 10 CFR 50.46a, "Acceptance Criteria for Reactor Coolant System Venting Systems" (see volume 67, page 50374 of the Federal Register, August 2, 2002). These proposed changes are meant to risk-inform the combustible gas control requirements, and constitute significant relaxations of the requirements.
Section 6.2.5 of this report contains the staff's evaluation of combustible gas control. As set forth in this section, the staff identified the resolution of issues associated with combustible gas control as Open Item 6.2.5-1.

The AP1000 DCD was written in anticipation of these rule changes. The proposed rule changes became effective on October 16, 2003. Therefore, Open Item 6.2.5-1 is resolved, and omission of a specification corresponding to STS 3.6.8 is acceptable.

AP1000 TS 3.6.7 was developed for the pH adjustment of the containment sump water for controlling release of radionuclides from water in the containment following a LOCA with fuel damage. The containment sump water pH control is actually a part of the PXS system. Control of the pH in the containment sump water after an accident is achieved through the use of pH adjustment baskets containing granulated trisodium phosphate (TSP) in the containment sump. Maintaining a proper alkaline pH range reduces offsite doses by decreasing the radiolytic formation of elemental iodine in the containment sump, the resulting formation of organic iodine, and subsequent production of airborne iodine. This feature accomplishes the same purpose as the sodium hydroxide chemical additive in the containment spray system, upon which STS 3.6.6A and 3.6.7 are based. This pH adjustment function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The AP1000 TS 3.6.8 for containment penetrations in Modes 5 and 6 is in addition to the containment penetration specification, TS 3.9.5, which is based on STS 3.9.4 and only applies during movement of irradiated fuel assemblies in containment. Section 3.6 of the STS does not contain this specification. The purpose of TS 3.6.8 is to ensure that in the event of a loss of normal cooling in Modes 5 and 6, the containment can be closed before reactor coolant steaming occurs. This in turn will maintain the cooling water inventory within containment necessary to support either PRHR or IRWST injection and containment sump recirculation for postulated shutdown events in Modes 5 and 6. The capability to close containment prior to steaming satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Section 3.6 of the AP1000 TS does not contain specifications corresponding to STS 3.6.9 for hydrogen mixing, 3.6.11 for iodine cleanup, or 3.6.12 for containment vacuum relief valves because the AP1000 design either does not contain these features or does not credit them in the safety analyses.

The AP1000 specifications associated with containment systems implement modified versions of the STS for containment systems. The staff finds that these specifications have been constructed to be essentially equivalent to the STS for the containment cooling and isolation functions. The staff agrees that for those cases in which the corresponding STS have not been included, AP1000 design differences provide sufficient justification for such omissions. Therefore, the staff finds the AP1000 containment system specifications acceptable.

16.2.10 AP1000 TS Section 3.7, "Plant Systems"

The AP1000 TS for plant systems correspond to the STS as follows:

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
3.7.1*	3.7.1	Main Steam Safety Valves (MSSVs) (*Main Steam Safety Valves)
3.7.2*	3.7.2	Main Steam Isolation Valves (MSIVs) (*Main Steam Isolation Valves)
3.7.3*	3.7.3	Main Feedwater Isolation and Control Valves (MFIVs and MFCVs) (*MFIVs and Main Feedwater Regulation Valves (MFRVs))
3.7.5*	None	(*Auxiliary Feedwater (AFW) System)
3.7.6*	None	(*Condensate Storage Tank (CST))
3.7.7*	None	(*Component Cooling Water (CCW) System)
3.7.8*	None	(*Service Water System (SWS))
3.7.9*	None	(*Ultimate Heat Sink (UHS))

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
3.7.18*	3.7.4	Secondary Specific Activity (*same)
3.7.15*	3.7.5	Spent Fuel Pool Water Level (*Fuel Storage Pool Water Level)
3.7.10*	3.7.6	Main Control Room Habitability System (VES) (*Control Room Emergency Filtration System (CREFS))
3.7.11*	None	(*Control Room Emergency Air Temperature Control System (CREATCS))
None	3.7.7	Startup Feedwater Isolation and Control Valves
None	3.7.8	Main Steam Line Leakage
None	3.7.9	Fuel Storage Pool Makeup Water Sources
3.7.4*	3.7.10	Steam Generator Isolation Valves (*Atmospheric Dump Valves (ADVs))
3.7.12*	None	(*ECCS Pump Room Exhaust Air Cleanup System (PREACS))
3.7.13*	None	(*Fuel Building Air Cleanup System (FBACS))
3.7.14*	None	(*Penetration Room PREACS)
3.7.16*	None	(*Fuel Storage Pool Boron Concentration)
3.7.17*	None	(*Spent Fuel Pool Storage)

The AP1000 main steam safety valve (MSSV) specification differs from the STS because the AP1000 design has two steam generators (SGs), each with six MSSVs, rather than four SGs, each with up to five MSSVs. The AP1000 main steam isolation valve (MSIV) specification differs from that of the STS primarily to account for reliance on the non-safety-related turbine stop or control valves, in combination with the turbine bypass and moisture separator reheat supply steam control valves, as a backup to isolating the steam flow path, given a single failure of an MSIV in response to a steam line break. The AP1000 main feedwater isolation valve (MFIV) and main feedwater control valve (MFCV) specifications differ from the STS because of the fewer number of valves in the AP1000 design and in the required actions, which include the option of placing the plant in Mode 5 instead of isolating the flow path with the inoperable valve(s). Accordingly, the difference between these three specifications and the STS reflect the AP1000 design. Therefore TS 3.7.1, 3.7.2, and 3.7.3 are acceptable.

AP1000 TS 3.7.4 for secondary specific activity and TS 3.7.5 for spent fuel pool water level are essentially the same as the corresponding STS specifications. Therefore, they are acceptable.

The AP1000 uses the non-safety-related startup feedwater system to perform the non-safety functions that the safety-related auxiliary feedwater system performs for an operating PWR. These functions include supplying the SGs with feedwater during conditions of plant startup, hot standby, and shutdown, as well as during transients in the event the main feedwater system is unavailable. In the AP1000, the PRHR system (TS 3.4.5 and 3.5.5) provides the safety-related decay heat removal system instead of auxiliary feedwater (AFW) flow from the CST via a turbine-driven AFW pump to an SG expelling decay heat through release of steam by an atmospheric dump valve (ADV). Consequently, AP1000 TS which correspond to the STS specifications for the AFW system and CST are not required and are therefore omitted. A specification for the energy release function of the ADVs is also omitted because the AP1000 design does not rely on the ADVs as a safety-related method of emergency RCS heat removal. However, the SG isolation function of the ADVs is included as discussed in the evaluation of AP1000 TS 3.7.10. Omission of these STS requirements is acceptable because of design differences between the AP1000 and currently operating plants, which are the basis for the STS.

The AP1000 TS do not contain specifications for the component cooling water system (CCS), the service water system (SWS), or the ultimate heat sink (UHS). The CCS and the SWS are not safety-related in the AP1000 design. The SWS supports the CCS by supplying cooling water to remove heat from the CCS heat exchangers. The SWS rejects the heat to a heat sink, such as a cooling tower system. The CCS is a closed system that removes heat from various components needed for plant operation. The CCS also removes core decay heat and sensible heat through the normal residual heat removal system heat exchangers (RNS HXs) during normal reactor shutdown and cooldown. The PXS and the PCS provide safety-related heat removal in the event of a DBA; these systems do not rely on the CCS and SWS. Omission of specifications for the CCS, SWS, and UHS (cooling tower) is acceptable because these systems do not perform safety-related functions and do not satisfy any of the criteria in 10 CFR 50.36(c)(2)(ii).

The residual heat removal function of the RNS, CCS, and SWS during Modes 5 and 6 with the RCS open was determined to be significant from a RTNSS perspective. This is discussed in WCAP-15985, Revision 1. Thus, these three systems are included in the short-term availability controls.

AP1000 TS 3.7.6 contains requirements for the main control room habitability system (VES) which provides safety-related control room ventilation and radiation protection. To maintain a safe environment in the control room in the event of a DBA, the VES does not rely on ventilation filtering of outside air, which may contain radioactivity, or on air conditioning units for temperature control, as described in the STS for the control room emergency filtration system (CREFS) and the control room emergency air temperature control system (CREATCS), respectively. If radiation monitors in the nuclear island nonradioactive ventilation system (VBS) actuate, the VBS is automatically isolated and the VES will initiate to supply breathable air from compressed air storage tanks for 72 hours. The VES also maintains the control room pressurized with respect to the environment outside the control room boundary to minimize outside air in-leakage. In addition, the thermal design of the control room boundary, along with the VES air supply, will maintain the control room temperature within limits. This specification is consistent with the format and usage rules of the STS and will ensure that the VES system will be able to perform its intended function. The VES satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Therefore, TS 3.7.6 is acceptable. In addition, requirements corresponding to the STS for the CREFS and CREATCS are not required in the AP1000 TS because the VBS is not assumed to function to limit doses to control room personnel in accordance with General Design Criteria 19, "Control Room."

The AP1000 TS 3.7.7 for the isolation and control valves of the startup feedwater system is a new specification to ensure isolation of feedwater flow to the SGs from the startup feedwater system in the event of a break in a feedwater or steam line, a SGTR, or other secondary side event. Isolation is necessary to limit the mass and energy added to containment from a feedwater line break or a steam line break event inside containment. Isolation also prevents SG overfill in the event of a SGTR. This specification is consistent with the format and usage rules of the STS and will ensure isolation of the startup feedwater system when required. Therefore, TS 3.7.7 is acceptable.

The AP1000 applies leak-before-break technology to the main steam line and the primary coolant system, while currently operating PWRs only apply this technology to the primary coolant system. A new specification, TS 3.7.8 for main steam line leakage, is provided to account for these differences. The STS do not contain a corresponding specification. This specification is consistent with the format and usage rules of the STS and will ensure that degradation of the integrity of main steam system lines inside containment will be detected before the leak before break leak rate criterion is reached. This specification will also ensure that the plant is brought to Mode 5 to preclude the leak from causing further degradation which could lead to a steam line break. The main steam line leakage limit does not affect a fission product barrier and is not an initial condition of a DBA. Accordingly, this limit does not satisfy any of the criteria in 10 CFR 50.36(c)(2)(ii), but is included in the TS for defense in depth. Therefore, TS 3.7.8 is acceptable.

AP1000 TS 3.7.9 was added to require the availability of a spent fuel pool makeup water source under certain spent fuel pool decay heat loads. The STS do not contain a corresponding specification. The makeup water replaces the water lost through pool water boiling in the event of a loss of normal cooling by the non-safety spent fuel pool cooling system for an extended period. The PCS water storage tank and the cask wash down pit serve as the required water sources. The spent fuel pool makeup function is not an initial condition of any DBA and does not mitigate any DBA that assumes the failure of or presents a challenge to the integrity of a fission product barrier. Accordingly, this function does not satisfy any of the criteria in 10 CFR 50.36(c)(2)(ii), but is included in the TS for defense in depth. This specification is consistent with the format and usage rules of the STS and will ensure the availability of a makeup water source in the event that normal pool cooling is lost and boiling occurs in the pool. Therefore, TS 3.7.9 is acceptable.

The AP1000 TS add a specification for SG isolation valves, TS 3.7.10. This specification ensures the capability to automatically isolate the SG PORV flow paths (both the PORV, which functions as an ADV, and the associated block valve) following a SGTR to minimize radiological releases from the affected SG. It also ensures the capability to automatically isolate the SG blowdown line from each SG following a loss of feedwater or a feedwater line break in order to retain SG water inventory for RCS heat removal using the SGs.

TS 3.7.10 is consistent with the format and usage rules of the STS and satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Conditions C and D of the action requirements specify an 8-hour completion time to correct a loss of SG automatic isolation capability. The Bases justify the 8-hour interval using insights from the AP1000 PRA. These completion times are related to the staff review of the AP1000 PRA. The NRC staff determined that Open Item 19.1.10.1-3 was resolved because the applicant had properly used AP1000 PRA results. Therefore, TS 3.7.10 is acceptable.

Section 3.7 of the AP1000 TS implements modified versions of the STS plant system specifications. The staff finds that these specifications have been constructed to be essentially equivalent to the STS for plant systems. The staff agrees that for those cases in which a TS corresponding to the STS has not been included, AP1000 design differences provide sufficient justification for such an omission. Therefore, the staff finds the AP1000 plant system specifications acceptable.

16.2.11 AP1000 TS Section 3.8, "Electrical Power Systems"

The AP1000 does not rely on alternating current (ac) power to mitigate DBAs or to attain safe shutdown (except for I&C which is ultimately powered from the direct current (dc) system). Thus, STS 3.8.1 for ac sources-operating, STS 3.8.2 for ac sources-shutdown, and STS 3.8.3 for diesel fuel oil, lube oil, and starting air are not required. Therefore, omitting specifications for the corresponding AP1000 non-safety systems is acceptable. However, ac power sources have been determined to be important from a RTNSS perspective and are consequently included in the short-term availability controls.

The AP1000 TS for electrical power systems include specifications corresponding to STS 3.8.4 and 3.8.5 for dc sources - both operating and shutdown (TS 3.8.1 and TS 3.8.2); STS 3.8.6 for battery parameters (TS 3.8.7); STS 3.8.7 and 3.8.8 for inverters - both operating and shutdown (TS 3.8.3 and 3.8.4); and STS 3.8.9 and 3.8.10 for distribution systems - both operating and shutdown (TS 3.8.5 and 3.8.6). The staff finds these electrical power system specifications acceptable, but notes the following difference between the AP1000 TS and the STS. The completion time for one dc subsystem inoperable was extended from 2 hours to 6 hours based on the continued capability of the AP1000 to reach safe shutdown and mitigate all DBAs with the capacity of the remaining dc subsystems. A 2-hour completion time was added for two dc subsystems inoperable to permit limited time to assess and restore an inoperable dc subsystem on the basis of the AP1000 capability to reach safe shutdown with two subsystems inoperable, as well as its ability to mitigate most DBAs. Other specifications on inverters, distribution subsystems, and battery cell parameters are either consistent with the STS or have only minor, acceptable variations.

The AP1000 TS associated with the electrical power system implement modified versions of the STS for the dc electrical power systems. The staff finds that these specifications have been constructed to be essentially equivalent to the STS for the corresponding electrical power system functions. The staff agrees that for those cases in which a TS corresponding to the STS has not been included, AP1000 design differences provide sufficient justification for such an omission. Therefore, the staff finds the AP1000 electrical power system TS acceptable.

16.2.12 AP1000 TS Section 3.9, "Refueling Operations"

The AP1000 TS for refueling operations compare closely to the corresponding STS provisions, with only a few exceptions. The correspondence between Section 3.9 of the AP1000 TS and Section 3.9 of the STS is as follows:

STS	AP1000 TS	AP1000 TS TITLE (*STS TITLE)
3.9.1*	3.9.1	Boron Concentration (*same)
3.9.2*	3.9.2	Unborated Water Source Flow Paths (*Unborated Water Source Isolation Valves)
3.9.3*	3.9.3	Nuclear Instrumentation (*same)
3.9.7*	3.9.4	Refueling Cavity Water Level (*same)
3.9.4*	3.9.5	Containment Penetrations (*same)
None	3.9.6	Containment Air Filtration System (VFS)
3.9.5*	None	(*Residual Heat Removal and Coolant Circulation - High Water Level)
3.9.6*	None	(*Residual Heat Removal and Coolant Circulation - Low Water Level)
None	3.9.7	Decay Time

The AP1000 specifications for boron concentration, unborated water sources, nuclear instrumentation, and refueling cavity water level contain no significant differences from the corresponding STS specifications. Therefore, TS 3.9.1, 3.9.2, 3.9.3, and 3.9.4 are acceptable.

AP1000 TS 3.9.5 for containment penetrations during movement of irradiated fuel assemblies within containment differs from the STS in two respects. Unlike the STS, maintaining closure of the containment penetrations during fuel movement does not satisfy the criteria of 10 CFR 50.36(c)(2)(ii). Rather, TS 3.9.5 is provided as an additional level of defense for the in-containment fuel handling accident (FHA). The design-basis, in-containment FHA safety analysis shows acceptable dose consequences without crediting containment closure or filtration of containment ventilation exhaust. In addition, LCO 3.9.5 specifies the option of placing the non-safety-related containment air filtration system (VFS) in operation in lieu of satisfying the closure provision for the equipment hatch, the personnel airlock, and the containment spare penetrations. This option for meeting the LCO will ensure filtration of containment ventilation exhaust in the event of a FHA involving fuel damage. The staff finds that these two differences are appropriate for the AP1000 design because containment closure and VFS operation are not credited in the inside-containment FHA analysis. Also, specifying two options for meeting the LCO provides operational flexibility during fuel movement inside containment. Therefore, TS 3.9.5 is acceptable.

Section 3.9 of the AP1000 TS includes a separate specification for the VFS, applicable during irradiated fuel movement in the fuel building, to establish the LCO, required action, and surveillance requirements for this FHA defense in depth feature. This specification is consistent with the format and usage rules of the STS. The design-basis, fuel building FHA safety analysis demonstrates acceptable dose consequences without crediting filtration of fuel building ventilation exhaust by the VFS. Accordingly, mitigation of a fuel building FHA by the VFS does not satisfy the criteria of 10 CFR 50.36(c)(2)(ii). This function is included in the AP1000 TS for defense in depth. Therefore, TS 3.9.6 is acceptable.

The AP1000 TS do not include a specification for the non-safety-related normal residual heat removal system (RNS), which corresponds to the residual heat removal system in the STS. The AP1000 employs passive safety-related methods for removing decay heat when the plant is in the refueling mode. One such method is feed-and-bleed from the IRWST if water remains available in the IRWST. If not, then decay heat may be removed by refueling cavity boiling if the refueling canal is full and the reactor pressure vessel upper internals are removed. To retain sufficient coolant inventory using this method, the containment must be closed. Because the accident analyses do not assume that the RNS will function in a loss of cooling event during refueling shutdown conditions, the AP1000 RNS does not satisfy the criteria of 10 CFR 50.36(c)(2)(ii). However, RNS short-term availability controls have been established for plant conditions during which the RNS has been determined to be important from a RTNSS perspective. Therefore, omitting specifications corresponding to the STS residual heat removal requirements during refueling operations is acceptable.

The time interval between the time the reactor was last critical and the initial movement of an irradiated fuel assembly from the reactor core is a key assumption in the dose consequence estimates of an AP1000 design-basis FHA analysis, as well as in the spent fuel pool cooling requirements. As such, this decay time satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) and is required to be included in an LCO in AP1000 TS, preferably in TS Section 3.9. The applicant did not propose a decay time specification in the AP1000 TS. This was Open Item 16.2-3 in the DSER.

In its response to Open Item 16.2-3, the applicant proposed to add TS 3.9.7, "Decay Time," and the associated Bases. This specification provides a decay time limit and associated action and surveillance requirements consistent with the AP1000 FHA analysis, STS format, and requirements of 10 CFR 50.36. Therefore, TS 3.9.7 is acceptable and Open Item 16.2-3 is resolved.

The AP1000 TS associated with refueling operations implement modified versions of the STS for refueling operations. The staff finds that these specifications have been constructed to be essentially equivalent to the STS for the corresponding refueling constraints. The staff agrees that for those cases in which a TS corresponding to the STS has not been included, AP1000 design differences provide sufficient justification for such an omission. Therefore, the staff finds the AP1000 refueling operations TS acceptable.

16.2.13 AP1000 Shutdown Operations

The applicant proposed new TS to control the availability of portions of the PXS, PCS, containment closure, and related systems during shutdown operations (Modes 5 and 6). These new specifications are intended to maintain the capability of passively cooling the core and maintaining cooling water inventory inside the containment following loss of the RNS during shutdown operations. If the RCS boundary is closed, the PRHR system will eventually be able to remove core decay heat following heatup of the RCS. If the RCS is open, the loss of residual heat removal results in steam being released to the containment. Core cooling can be maintained via a feed-and-bleed-type injection from the IRWST and eventually long-term containment sump recirculation, if necessary. In either case (RCS open or closed), as long as the containment is closed and sufficient cooling is provided through the containment shell to condense the steam, the condensate will eventually drain back to the RCS, providing long-term decay heat removal. The TS for the ADS, PRHR, PCS, and containment penetrations provide assurance that portions of these systems and components will be maintained for shutdown conditions. In addition, a number of I&C ESFAS signals have been added to ensure the ability to actuate these systems during Modes 5 and 6.

The AP1000 TS associated with shutdown operations do not have equivalent STS versions. The staff finds that the shutdown operation TS have been constructed to be essentially equivalent to the STS format and usage rules. In addition, the staff finds these TS to be conservative or improved compared to the STS shutdown operations provisions. Therefore, the staff finds the AP1000 TS for shutdown operations to be acceptable.

16.2.14 AP1000 TS Section 4.0, "Design Features"

The AP1000 design features correspond to, and are consistent with, those specified in the STS. Therefore, Section 4.0 of the TS acceptable.

16.2.15 AP1000 TS Section 5.0, "Administrative Controls"

The AP1000 administrative controls correspond to, and are consistent with, those specified in the STS. Therefore, Section 5.0 of the TS is acceptable.

16.3 Conclusions

Based on the staff's review of the AP1000 TS, the staff concludes that the proposed AP1000 TS are consistent with the regulatory guidance contained in the STS. The proposed TS contain design-specific parameters and additional TS requirements considered appropriate by the staff. The staff concludes that the AP1000 TS comply with 10 CFR 50.34 and 10 CFR 50.36 and are, therefore, acceptable.

17. QUALITY ASSURANCE

17.1 Quality Assurance During the Design and Construction Phase

In the AP1000 Design Control Document (DCD) Tier 2, Section 17.5, "Combined License Information Items," Westinghouse (the applicant) states that the combined license (COL) applicant will address its quality assurance (QA) program for the design phase, as well as its QA program for procurement, fabrication, installation, construction, and testing of structures, systems, and components (SSCs) in the facility. Therefore, when applying for a COL, the staff will expect the COL applicant to submit its design phase QA program for review, in addition to the information needed to support the staff's review of the COL applicant's QA program for construction and operation of the facility. DCD Tier 2, Section 17.5, describes this COL action item. The U.S. Nuclear Regulatory Commission (NRC) staff agrees that the COL applicant is responsible for this part of the QA program and that making this a COL action item in DCD Tier 2, Section 17.5, is acceptable. This is COL Action Item 17.1-1.

17.2 Quality Assurance During the Operations Phase

In DCD Tier 2, Section 17.5, the applicant stated that the COL applicant will address its QA program for operations. DCD Tier 2, Section 17.5, describes this COL action item. The NRC staff agrees that the COL applicant is responsible for developing the operational QA program pursuant to Title 10 of the Code of Federal Regulations (10 CFR) Subsection 52.79(b) and 10 CFR 50.34(a)(7). Therefore, making this a COL item in DCD Tier 2, Section 17.5, is acceptable. This is COL Action Item 17.2-1.

17.3 Quality Assurance During the Design Phase

Title 10 of the Code of Federal Regulations (10 CFR) Subsection 52.47(a)(1)(i) requires, in part, that an application for design certification contain technical information which is required of applicants for construction permits and operating licenses by 10 CFR Part 50 and its appendices. The requirements of 10 CFR 50.34(a)(7) state, in part, that an applicant for a construction permit provide a description of the QA program to be applied to the design of SSCs. In addition, 10 CFR Part 52, Appendix O, "Standardization of Design: Staff Review of Standard Designs," states that the information submitted pursuant to Subsection 50.34(a)(7) shall be limited to the QA program to be applied to the design, procurement and fabrication of the SSCs for which the design review has been requested. The description of the QA program shall include a discussion of how it will satisfy the applicable requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Therefore, the staff reviewed the QA program used during the AP1000 design phase. Section 17.3, "Quality Assurance Program Description," of NRC technical report designation (NUREG)-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," (SRP) contains specific guidance for conducting this review.

17.3.1 General

DCD Tier 2, Section 17.3, outlines the QA program applicable to the design, procurement, fabrication, inspection, and/or testing of items and services for the AP1000 project. The design for the AP1000 is based on using the design of the AP600 to the maximum extent possible. As a result, the applicant stated that it has used a continuous QA program spanning the AP600 design, as well as the AP1000 design. Before March 31, 1996, activities for the AP600/AP1000 design program were performed in accordance with topical report WCAP-8370, "Westinghouse Energy Systems Business Unit/Power Generation Business Unit Quality Assurance Plan." Since March 31, 1996, activities affecting the quality of items and services for the AP1000 project during design, procurement, fabrication, inspection, and/or testing have been performed in accordance with the quality plan described in "Westinghouse Energy Systems Business Unit—Quality Management System." Since that time, the quality management system (QMS) has been maintained as the quality plan for the AP1000 program, and subsequent revisions have been submitted to and accepted by the NRC staff as meeting the requirements of 10 CFR Part 50, Appendix B. Revision 5, the current revision of the Westinghouse QMS, was implemented on October 1, 2002. The NRC staff previously had found that Revision 5 of the QMS continued to meet the requirements of 10 CFR Part 50, Appendix B, as documented in an NRC evaluation letter dated September 13, 2002, from W. Ruland to H. Sepp (ADAMS Accession No. ML022540895).

17.3.2 Evaluation

During the review of the AP1000 design QA program, the staff identified five areas where it required additional information to complete the QA program description and implementation review. These areas included (1) QA controls for non-safety-related, risk-significant SSCs identified by the regulatory treatment of non-safety systems (RTNSS) process defined in SECY-95-132, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Designs," dated May 22, 1995, (2) implementation of QA controls for AP1000 design testing, (3) implementation of the Westinghouse QMS for AP1000 design activities, (4) the basis for certain exceptions to quality-related regulatory guides, and (5) missing quality-related information in DCD Tier 2, Section 17.6, "References." In letters dated September 19, 2002, and April 16, 2003, the staff requested additional information to complete this review. The description and resolution of each of these five areas follow:

- Quality Assurance Controls for Structures, Systems, and Components Identified by the Regulatory Treatment of Non-Safety Systems Process

  The NRC staff reviewed the QA controls applicable to the SSCs within the RTNSS process to verify that adequate controls were specified to ensure the reliability and availability of risk-significant, non-safety-related SSCs. The staff utilized the guidance in SECY-95-132, which the Commission approved in a Staff Requirements Memorandum dated June 28, 1995, to facilitate this review. As described in SECY-95-132, the staff will consider graded requirements for QA and quality control consistent with the importance to safety of the systems identified by the RTNSS process. The applicant described QA controls for certain non-safety-related SSCs in DCD Tier 2, Table 17-1, "Quality Assurance Program Requirements for Systems, Structures, and Components Important to Investment Protection." The staff determined that the DCD Tier 2, Table 17-1, QA controls were generally consistent with the QA measures specified for non-safety-related SSCs in Generic Letter (GL) 85-06, "Quality Assurance Guidance for ATWS Equipment That Is Not Safety Related," and Regulatory Guide (RG) 1.155, "Station Blackout." Therefore, the staff determined that DCD Tier 2, Table 17-1, specified adequate graded QA controls for SSCs identified by the RTNSS process. However, in reviewing DCD Tier 2, Section 17.3, the staff determined that the applicant previously had revised the DCD Tier 2 information to remove SSCs within the RTNSS process from the scope of non-safety-related quality control requirements outlined in DCD Tier 2, Table 17-1. Because this revision eliminated the QA controls for SSCs within the RTNSS process, the staff determined that this DCD Tier 2 revision was not acceptable.

In request for additional information (RAI) 260.001, the NRC staff requested the applicant to either justify removal of SSCs identified by the RTNSS process from DCD Tier 2, Section 17.3, or to maintain the SSCs identified by the RTNSS process within the scope of the non-safety-related QA controls outlined in DCD Tier 2, Table 17-1. In a revision to DCD Tier 2, Section 17.3, the applicant placed SSCs identified by the RTNSS process within the scope of DCD Tier 2, Table 17-1. The NRC staff found that this meets the guidance in SECY-95-132 and SRP Section 17.3, and, therefore, is acceptable. On this basis, RAI 260.001 is resolved.

- Quality Assurance Issues Associated with AP1000 Design Testing

To support design certification of the AP1000 design, Westinghouse performed thermal hydraulic testing at the Advanced Plant Experiment (APEX)-1000 test facility, which the Oregon State University (OSU) Advanced Thermal Hydraulic Research Laboratory (ATHRL) operates in Corvallis, Oregon. To verify that these testing activities were in accordance with the Westinghouse QA program under 10 CFR Part 50, Appendix B, as described in DCD Tier 2, Chapter 17, the NRC staff performed a QA implementation inspection of the OSU ATHRL. The staff had previously identified performance of this inspection as draft safety evaluation report (DSER) Open Item 17.3.2-1.

From September 30–October 2, 2003, the NRC staff performed a QA inspection at the OSU ATHRL. The NRC performed the inspection to review the implementation of the OSU ATHRL quality plan as it relates to facility scaling and testing activities conducted in support of the Westinghouse AP1000 design certification. Westinghouse reviewed and accepted the ATHRL quality plan as meeting the requirements of 10 CFR Part 50, Appendix B for the AP1000 project activities. The NRC staff reviewed the areas covered by the ATHRL quality plan to confirm that test activities were adequately controlled, APEX-1000 test facility personnel were properly trained, and test data were properly recorded and maintained.

During this inspection, the NRC found that certain activities did not meet NRC requirements. For example, the ATHRL did not have a documented process or procedure to address the requirements of 10 CFR Part 21, "Reporting of Defects and Noncompliance," for facility scaling and testing activities performed at the APEX-1000 test facility. This issue was identified as Notice of Violation 99901351/2003-01-01 in NRC Inspection Report 99901351/2003-01 (ADAMS Accession No. ML033350274). In addition, the inspectors determined that certain activities at the ATHRL APEX-1000 test *facility were not conducted in accordance with NRC quality requirements.* Specifically, the OSU ATHRL quality plan failed to establish a corrective action program consistent with the requirements of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." It also failed to establish requirements for training record retention consistent with Criterion XVII, "Quality Assurance Records." In addition, OSU ATHRL staff could not produce the objective evidence necessary to demonstrate compliance with the ATHRL quality plan for drawing configuration control, control of measurement and test equipment, computer software control, and document control for certain APEX-1000 testing activities. The NRC inspection report *identified these issues in Notice of Nonconformance* 99901351/2003-01-01 *and* Notice of Nonconformance 99901351/2003-01-02.

On the basis of the findings identified in NRC Inspection Report 99901351/2003-01, the staff requested the OSU ATHRL to respond to the Notice of Violation and Notices of Nonconformance. In addition, the NRC requested Westinghouse to verify that the OSU ATHRL quality plan implemented for the AP1000 thermal-hydraulic testing was consistent with the Westinghouse QA program, as described in DCD Tier 2, Chapter 17. The staff required this information to resolve DSER Open Item 17.3.2-1.

OSU responded to the Notice of Violation and the two Notices of Nonconformance in letters to the NRC staff dated December 22 and December 23, 2003, and January 30, 2004 (ADAMS Accession Nos. ML033640531, ML033640533, and ML040350550, respectively). The staff reviewed the responses and determined that OSU adequately addressed the deficiencies noted during the inspection. In particular, OSU stated that it had issued a procedure compliant with 10 CFR Part 21 and revised the ATHRL quality plan to include a corrective action program and retention requirements for training records. In addition, OSU stated that it revised the quality plan to provide clear guidance for changes to test procedures and completed a walkdown to verify that the APEX-1000-controlled drawings reflected the as-built facility configuration. OSU also clarified corrective measures taken to address weaknesses in the control of measurement and test equipment, and clarified the methodology used to validate software for the APEX-1000 test facility. On the basis of the NRC staff review of the corrective actions and preventive measures implemented in the OSU response to Notice of Violation 99901351/2003-01-01, Notice of Nonconformance 99901351/2003-01-01, and Notice of Nonconformance 99901351/2003-01-02, the staff concludes that the identified findings do not significantly affect the integrity or reliability of the facility test data. Therefore, DSER Open Item 17.3.2-1 is resolved.

- Implementation of Quality Assurance Program for AP1000 Design

On September 15–18, 2003, the NRC staff conducted an AP1000 QA implementation inspection at the Westinghouse Energy Center in Monroeville, Pennsylvania. NRC Inspection Report 99900404/2003-01 (ADAMS Accession No. ML033090510) documents the results of the inspection. The NRC conducted the inspection to review implementation of the Westinghouse AP1000 project-specific quality plan and to verify that design activities conducted on the AP1000 project complied with the Westinghouse

QMS and the requirements of 10 CFR Part 50, Appendix B. The staff previously identified performance of this inspection as DSER Open Item 17.3.2-2.

The inspection team evaluated Westinghouse's oversight of design activities conducted by contractors and subcontractors, evaluation and disposition of Westinghouse internal audit findings, and implementation of corrective actions taken as a result of these audit findings. During the inspection, the NRC staff sampled the implementation of AP1000 project activities to verify that they met the QA requirements specified in 10 CFR Part 50, Appendix B, and 10 CFR 50.34(f)(3)(iii). In addition, the staff reviewed the applicant's compliance with the QA guidelines specified in NUREG-0933, "A Prioritization of Generic Safety Issues," Item I.F.2, "Develop More Detailed QA Criteria."

Regarding the requirements of 10 CFR 50.34(f)(3) and the guidance in NUREG-0933, Item I.F.2, the inspectors verified that QA personnel were involved in the approval of QA procedures. The Westinghouse Passive Plant Project and Development Staff prepared the QA procedures for the AP1000 project. Qualified QA personnel independently reviewed the procedures. Either the Passive Plant Project and Development Manager or the Westinghouse AP600 and AP1000 Projects Director signed the procedures. In addition, QA personnel reviewed design change proposals in accordance with AP1000 Program Operating Procedure AP-3.2, "Change Control for the AP1000 Program." The staff could not review information on QA personnel involved in construction, installation, testing, and operation activities because this is a COL applicant responsibility. The size of the QA staff involved in the AP1000 design certification project is adequate; however, the COL applicant will be responsible for QA staffing during the COL applicant design and construction phases. In addition, Westinghouse QA organizational reporting levels were determined to be adequate for the AP1000 design certification; however, the COL applicant will need to verify that QA organizational reporting levels are sufficient during the design and construction phases. This is COL Action Item 17.5-1 (see Section 17.5 of this report for additional details). Chapter 20, "Generic Issues," of this report contains further discussion of the applicant's compliance with NUREG-0933, Item I.F.2, guidance.

In reviewing the control of suppliers for the AP1000 project, the inspectors determined that Westinghouse could not produce objective evidence demonstrating compliance with Westinghouse quality program requirements for qualifying and evaluating suppliers used to support safety-related design certification activities for the AP1000 project. Specifically, as of August 19, 2003, the AP1000 suppliers list showed a total of 27 suppliers; however, Westinghouse could not produce objective evidence demonstrating that it had evaluated and audited 21 of the suppliers potentially active in providing safety-related services for the AP1000 Design Certification Program in ways consistent with Westinghouse procedures. The issue was identified as Notice of Nonconformance 99900404/2003-01-01. The inspectors also identified potential weaknesses in the applicant's audit and self-assessment programs. Specifically, the audit discussed in Westinghouse Electric Company (WEC) 02-20, performed on July 18, 2003, failed to identify the inadequacies in the AP1000 supplier qualification program that the inspectors later identified. In addition, the inspectors questioned whether a self-assessment for calculation quality met its prescribed objectives.

In letters dated December 3, 2003, and January 9 and February 6, 2004, Westinghouse responded to the issues identified by the inspectors (ADAMS Accession Nos. ML033440410, ML040140764, and ML040430245, respectively). The Westinghouse responses provided the following additional information:

- Regarding Notice of Nonconformance 99900404/2003-01-01, Westinghouse stated that noncompliance of lower tier AP1000 project-specific QA supplier qualification procedures with the higher tier Westinghouse QMS implementing procedures for supplier verification caused the failure to appropriately identify AP1000 suppliers. To correct this issue, Westinghouse stated that it had revised the AP1000 project-specific supplier qualification procedures, and that all safety-related AP1000 suppliers were qualified in accordance with the Westinghouse QMS. Westinghouse stated that it had established, for each non-Westinghouse AP1000 program contributor, a folder containing the following QA information:

  - documented evidence of Westinghouse's evaluation that the contributor's QA program meets the requirements of 10 CFR Part 50, Appendix B.

  - evidence of other independent audits performed on the contributor by other audit organizations (e.g., NQA-1 or ISO-9001 certification)

  - evaluation of previous work performed for AP600 and AP1000 and the current AP1000 evaluations based on a review of current work

  - documentation of Westinghouse audits performed on the contributor

  Westinghouse uses the folder to establish and maintain objective evidence that the AP1000 project contributors satisfy the applicable requirements of 10 CFR Part 50, Appendix B and the applicable design certification provisions of 10 CFR Part 52.

- Regarding the failure of Westinghouse internal audit WEC-02-20 to document the inspector-identified deficiencies in AP1000 supplier qualification, Westinghouse stated that the internal audit focused on compliance with the lower tier AP1000 project-specific procedures, rather than on compliance with QMS requirements. Because the lower tier AP1000 project-specific supplier qualification procedures did not comply with higher tier QA procedures, the internal audit failed to reveal that AP1000 supplier qualification was not performed in ways consistent with QMS requirements. Westinghouse stated that it has revised the lower tier AP1000 project procedures, and that this issue has been entered in the Westinghouse corrective action program to examine the scope of audits to ensure that they have the appropriate breadth and focus.

- Westinghouse also clarified the intent and approach used for the self-assessments, and the NRC staff determined that the approach used by Westinghouse for the self-assessments was acceptable.

The NRC staff found that the corrective actions taken by Westinghouse were reasonable and adequately addressed the issues identified during the QA implementation inspection. Therefore, DSER Open Item 17.3.2-2 is resolved.

- Compliance with Regulatory Guides Related to Quality Assurance

The NRC staff reviewed DCD Tier 2, Appendix 1A, "Conformance with Regulatory Guides," and noted that the applicant had taken exceptions to regulatory positions in several QA-related RGs. Specifically, the applicant identified exceptions to quality control guidance in the following five RGs:

(1) RG 1.28, "Quality Assurance Program Requirements (Design and Construction)"

(2) RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants"

(3) RG 1.38, "Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants"

(4) RG 1.39, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants"

(5) RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants"

The staff's evaluation of the exceptions to each of these RGs follows.

Exception to RG 1.28: As noted previously in this chapter, in DCD Tier 2, Appendix 1A, the applicant took exception to the record retention recommendations in RG 1.28. Specifically, RG 1.28, Regulatory Position C.2, "Quality Assurance Records," states that programmatic, nonpermanent records should be retained for at least 3 years. For programmatic, nonpermanent records, the retention period should be considered to begin upon completion of the activity. In addition, RG 1.28 states that product and programmatic, nonpermanent records should be retained at least until the date of issuance of the full-power operating license of the unit. Under 10 CFR Part 52, issuance of a COL is comparable to issuance of a full-power operating license under 10 CFR Part 50. The applicant stated that because a definitive schedule for obtaining a full-power operating license does not exist, the record retention plan is keyed to the final design approval. The applicant stated that a 3-year programmatic record retention period will be initiated on the date that the NRC issues an AP1000 final design approval. The NRC staff determined that this exception to RG 1.28 may not be acceptable because programmatic, nonpermanent records could be discarded 3 years after issuance of a final design approval. Therefore, these records may not be available to a future COL applicant. The NRC staff requested additional information (RAI 260.007) to assess the basis for not retaining nonpermanent records until a COL is issued. This issue was identified as DSER Open Item 17.3.2-3.

Westinghouse revised DCD Tier 2, Appendix 1A to state that the QA records will now conform to RG 1.28 and Appendix B, Criterion 17, "Quality Assurance Records." On the basis of this revision to DCD Tier 2, Appendix 1A, the NRC staff determined that DSER Open Item 17.3.2-3 is resolved.

Exceptions to RGs 1.37, 1.38, and 1.39: These RGs reference use of American National Standards Institute (ANSI) Standards N45.2-1, N45.2-2, and N45.2-3. However, the applicant referenced the requirements in American Society of Mechanical Engineers (ASME) Quality Standards, NQA-1 and NQA-2, rather than these ANSI standards. The requirements in ANSI N45.2-1, N45.2-2, and N45.2-3 have been updated and incorporated into ASME Quality Standards, NQA-1 and NQA-2. Because the staff considered incorporation of these ANSI standards into the guidance in ASME NQA-1 and NQA-2 as enhancements, the NRC staff finds that these RG exceptions are acceptable. The staff also noted that these three RGs are associated with COL activities. Therefore, the staff asked the applicant to annotate the discussion of RGs 1.37 and 1.38 in DCD Tier 2, Appendix 1A to indicate the need for a COL applicant to address implementation of these RGs, using an annotation similar to that in RG 1.39. The applicant revised DCD Tier 2, Appendix 1A, to add the reference to the COL information in DCD Tier 2, Section 17.5, similar to the annotation for RG 1.39. For these reasons, the NRC staff finds that the exceptions to RGs 1.37, 1.38, and 1.39 are acceptable.

Exception to RG 1.54, Revision 1: The NRC staff found that the applicant took exception to RG 1.54, Revision 1. As described in DSER Section 6.1.2.1, "Protective Coatings," the staff determined that the applicant met the QA requirements of 10 CFR Part 50, Appendix B, for safety-related protective coatings inside containment. However, some coatings inside containment are non-safety-related in the AP1000 design. The applicant addressed this exception to RG 1.54 in its response to RAI 281.001 (see Section 6.1.2, "Protective Coating Systems (Paints) - Organic Materials," of this report for additional details). The NRC staff found that this exception to RG 1.54 is acceptable based on the staff evaluation in Section 6.1.2 of this report.

- Missing Information Related to Quality Assurance in DCD Tier 2, Section 17.6, "References"

The NRC staff also noted that in DCD Tier 2, Section 17.6, "References," the applicant did not reference the following documents discussed in DCD Tier 2, Section 17.3:

- "Westinghouse Electric Company Quality Management System (QMS)," Revision 5, dated October 1, 2002

- WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Non-Safety-Related Systems Process," Revision 2, dated August 2003

Because these references were associated with QA program elements, the NRC staff asked Westinghouse to add these references to DCD Tier 2, Section 17.6. In addition, the staff noted that the DCD contained no reference to a project-specific quality plan for the AP1000 design similar to Reference 4, WCAP-12600, "AP600 Advanced Light Water Reactor Design Quality Assurance Program Plan," Revision 4, dated January 1998. The NRC requested this information from Westinghouse in RAI 261.008. This issue was identified as DSER Open Item 17.3.2-4.

In a revision to DCD Tier 2, Section 17.6, "References," Westinghouse added Item 9, "Westinghouse Electric Company Quality Management System (QMS)," Revision 5, dated October 1, 2002. Therefore, Westinghouse is implementing their QMS in accordance with 10 CFR Part 50, Appendix B QA program for the AP1000 design. The staff finds this reference document acceptable for implementing a project-specific quality plan for the AP1000 design.

In its response, Westinghouse stated that WCAP-15985 is a reference document on the docket for the AP1000 design (ADAMS Accession No. ML023370584); therefore, DCD Tier 2, Section 17.6 need not reference this document. Further, Westinghouse noted that DCD Tier 2, Chapter 16, "Technical Specification," (TS) contains a reference to WCAP-15985 in TS Bases 3.3.5 for the diverse actuation system. The NRC staff concluded that the DCD adequately referenced WCAP-15985 and that DCD Tier 2, Section 17.6 need not list this item. This resolves Open Item 17.3.2-4.

17.3.3 Conclusions

The staff determined that Westinghouse maintains a QA program reviewed and approved by the NRC that complies with the requirements of 10 CFR Part 50, Appendix B. Furthermore, the staff concludes that Westinghouse provided an adequate basis for all exceptions to the regulatory positions contained in QA-related RGs. On the basis of inspections performed at the OSU ATHRL in Corvallis, Oregon, and Westinghouse offices in Monroeville, Pennsylvania, the staff has reasonable assurance that Westinghouse adequately implemented QA controls for testing and design activities. Regarding the QA controls applied to non-safety-related SSCs within the RTNSS process, the staff concludes that Westinghouse identified appropriately graded QA guidelines for this risk-significant equipment.

17.4 Reliability Assurance Program During the Design Phase

SECY-95-132 outlines the requirements for a design certification reliability assurance program (RAP). The RAP provides reasonable assurance that (1) an advanced reactor is designed, constructed, and operated in a manner that is consistent with the assumptions and risk insights for risk-significant SSCs; (2) the risk-significant SSCs do not degrade to an unacceptable level during plant operations, (3) the frequency of transients that challenge advanced reactor SSCs are minimized, and (4) risk-significant SSCs function reliably when challenged.

The RAP for advanced reactors is implemented in two stages. The first stage, the design RAP (D-RAP), applies before the initial fuel load; the second stage, the operational reliability assurance process (O-RAP), applies to reliability assurance activities for the operations phase of the plant life cycle. The NRC staff reviews the D-RAP during design certification and the O-RAP during the COL stage.

The NRC staff drafted SRP Section 17.4, "Reliability Assurance Program," dated April 1996, to provide guidance for reviewing RAPs. The NRC staff's evaluation of the Westinghouse AP1000 RAP is based on the staff positions discussed in SECY-95-132 and the guidance in draft SRP Section 17.4. An application for advanced reactor design certification or a combined license must contain the following:

- the description of the RAP used during the design that includes scope, purpose, objectives, and essential elements of the D-RAP
- the process used to evaluate and prioritize the structures, systems, and components in the design on the basis of their degrees of risk significance
- a list of the structures, systems, and components designated as risk significant
- for the structures, systems, and components designated as risk significant, (1) a process for determining dominant failure modes that considered industry experience, analytical models, and applicable requirements, and (2) key assumptions and risk insights from probabilistic, deterministic, or other methods that considered operation, maintenance, and monitoring activities

The NRC staff reviewed the proposed D-RAP for the AP1000 design using the guidance in draft SRP Section 17.4 and SECY-95-132. The NRC staff also reviewed information from the AP1000 probabilistic risk assessment (PRA), Chapter 50, "Importance and Sensitivity Analysis," deterministic methods, and expert judgment from all chapters of the DCD to evaluate whether all risk-significant SSCs had been identified for inclusion in the D-RAP for the AP1000 design.

17.4.1 General

In a revision of DCD Tier 2, Section 17.4.1, Westinghouse stated that the D-RAP, as shown in DCD Tier 2, Figure 17.4-1, is implemented in three phases. The first phase, Design Certification, defines the overall structure of the AP1000 D-RAP and implements the aspects of the program that apply to the design process. During this phase, risk-significant SSCs are identified for inclusion in the program by using probabilistic, deterministic, and other methods. Phase II, the post-design certification process, develops component maintenance recommendations for the plant's operation and maintenance activities for identified SSCs. The third phase is the site-specific phase, which introduces the plant's site-specific SSCs to the

D-RAP process. The designer performs Phase I. The COL applicant is responsible for Phases II and III.

The NRC staff determined that the general description of RAP phases in DCD Tier 2, Section 17.4.1, meets the intent of the guidance in SECY-95-132 and the acceptance criteria in draft SRP, Section 17.4. Therefore, the general description of the D-RAP phases is acceptable.

17.4.2 Scope

In DCD Tier 2, Section 17.4.2, Westinghouse stated the following:

> The D-RAP includes a design evaluation of the AP1000 and identifies the aspects of plant operations, maintenance, and performance monitoring pertinent to risk-significant SSCs. In addition to the PRA, deterministic tools, industry sources, and expert opinion are utilized to identify and prioritize those risk-significant SSCs.

The staff reviewed the AP1000 scope, purpose, objectives, and essential elements of the D-RAP in accordance with SECY-95-132 and draft SRP Section 17.4.

The NRC staff also compared the scope of SSCs under the D-RAP for the AP600 design to the scope of SSCs under the D-RAP for the AP1000 design to evaluate their differences. The NRC staff found that the scope of SSCs within the D-RAP for the two designs are very similar. However, the D-RAP for the AP1000 design added the following risk-significant component functions:

- compressed and instrument air system (CAS) air compressor transmitter
- passive containment cooling system (PCS) diverse third motor-operated drain isolation valve function
- in-containment refueling water storage tank (IRWST) vents
- normal residual heat removal (RNS) valve V055 function
- main feedwater isolation valves

The D-RAP for the AP1000 design also removed passive core cooling condensate sump recirculation valve automatic open function and normal valve position, and revised the instrumentation and control (I&C) terminology for some I&C systems (e.g., the plant protection subsystem replaces reactor trip and engineered safety feature (ESF) subsystems). The resolution of RAIs 260.002 and 260.003 discusses the scope of SSCs within the RAP for the AP1000 design (see Section 17.4.7 of this report). The NRC staff finds that DCD Tier 2, Section 17.4.2, is consistent with the provisions used to determine the scope of risk-significant

SSCs in the D-RAP in SECY-95-132 and the acceptance criteria in draft SRP Section 17.4. Therefore, the scope of the D-RAP for the AP1000 design is acceptable.

17.4.3 Design Considerations

In DCD Tier 2, Section 17.4.3, "Design Considerations," Westinghouse states the following:

> As part of the design process, risk-significant components are evaluated to determine their dominant failure modes and the effects associated with those failure modes. For most components, a substantial operating history is available which defines the significant failure modes and their likely causes.
>
> The identification and prioritization of the various possible failure modes for each component lead to suggestions for failure prevention or mitigation. This information is provided as input to the Combined License applicant's O-RAP.
>
> The design reflects the reliability values assumed in the design and PRA as part of procurement specifications. When an alternative design is proposed to improve performance in either area, the revised design is first reviewed to provide confidence that the current assumptions in the other areas are not violated. When a potential conflict exists between safety goals and other goals, safety goals take precedence.

The NRC staff finds that these design considerations in DCD Tier 2, Section 17.4.3, are an essential element for identifying risk-significant SSCs and their failure modes, and are consistent with their descriptions in SECY-95-132 and the acceptance criteria in draft SRP Section 17.4. Therefore, these design considerations are acceptable.

17.4.4 Relationship to Other Administrative Programs

In DCD Tier 2, Section 17.4.4, "Relationship to Other Administrative Programs," Westinghouse states that the D-RAP manifests itself in other administrative and operational programs. The TS contain surveillance and testing frequencies for certain risk-significant SSCs, providing confidence that the reliability values assumed for them in the PRA will be maintained during plant operations. The scope of the D-RAP includes risk-significant systems that provide defense in depth or result in significant improvement in the PRA evaluations.

Westinghouse also states that the O-RAP can be implemented through the plant's existing programs for maintenance or QA. For example, the plant's implementation of the Maintenance Rule (10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants") can provide coverage of the SSCs that the O-RAP would include. The COL applicant will be responsible for the submittal of an O-RAP to the NRC. The NRC staff will review this process as part of the plant's maintenance program, QA program, or other existing programs.

The NRC staff finds that using QA and maintenance rule programs to implement parts of the D-RAP and O-RAP, as noted in DCD Tier 2, Section 17.4.4, is consistent with the essential elements of the D-RAP, as specified in SECY-95-132 and the acceptance criteria in draft SRP Section 17.4. Therefore, these essential elements of the AP1000 D-RAP are acceptable.

17.4.5 The AP1000 Design Organization

In DCD Tier 2, Section 17.4.5, "The AP1000 Design Organization," Westinghouse stated the following:

> The AP1000 organization of [DCD Tier 2,] Section 1.4 formulates and implements the AP1000 D-RAP.
>
> The AP1000 management staff is responsible for the AP1000 design and licensing.
>
> The AP1000 staff coordinates the program activities, including those performed within Westinghouse as well as work completed by the architect-engineers and other supporting organizations listed in [DCD Tier 2,] Section 1.4.
>
> The AP1000 staff is responsible for development of Phase I of the D-RAP and the design, analyses, and risk and reliability engineering required to support development of the program. Westinghouse is responsible for the safety analyses, the reliability analyses, and the PRA.
>
> The reliability analyses are performed using common databases from Westinghouse and from industry sources such as [Institute of Nuclear Power Operations] INPO and [Electrical Power Research Institute] EPRI.
>
> The Risk and Reliability organization is responsible for developing the D-RAP and has direct access to the AP1000 staff. Risk and Reliability is responsible for keeping the AP1000 staff cognizant of the D-RAP risk-significant items, program needs, and status. Risk and Reliability participates in the design change control process for the purpose of providing D-RAP-related inputs in the design process. Additionally, a cognizant representative of Risk and Reliability is present at design reviews. Through these interfaces, Risk and Reliability can identify interfaces between the performance of risk-significant SSCs and the reliability assumptions in the PRA. Meetings between Risk and Reliability and the designer are then held to manage interface issues.

The NRC staff has reviewed the description of the AP1000 design organization and finds that DCD Tier 2, Section 17.4.5, is consistent with the description of the organizational structure needed to implement the D-RAP in SECY-95-132 and draft SRP Section 17.4. Therefore, the AP1000 design organization is acceptable.

17.4.6 Objective

DCD Tier 2, Section 17.4.6, "Objective," Westinghouse states the following:

> The objective of the D-RAP is to design reliability into the plant and to maintain the AP1000 reliability consistent with the NRC-established PRA safety goals.
>
> The following goals have been established for the D-RAP:
>
> - Provide reasonable assurance that
>   - The AP1000 is designed, procured, constructed, maintained and operated in a manner consistent with the assumptions and risk insights in the AP1000 PRA for these risk-significant SSCs
>   - The risk-significant SSCs do not degrade to an unacceptable level during plant operations
>   - The frequency of transients that challenge the AP1000 risk-significant SSCs are minimized
>   - The risk-significant SSCs function reliably when they are challenged
> - Provide a mechanism for establishing baseline reliability values for risk-significant SSCs identified by the risk determination methods used to implement the Maintenance Rule (10 CFR 50.65) and consistent with PRA reliability and availability design-basis assumptions used for the AP1000 design
> - Provide a mechanism for establishing baseline reliability values for SSCs consistent with the defense-in-depth functions to minimize challenges to the safety-related systems
> - Generate design and operational information to be used by a Combined License applicant for ongoing plant reliability assurance activities
>
> Development of maintenance assessments and recommendations for the D-RAP (Phase II) and the site specific portion of the D-RAP (Phase III) is the responsibility of the Combined License applicant.
>
> The Combined License applicant is responsible for submitting its maintenance recommendations (Phase II) and site specific (Phase III) D-RAP organization description to the NRC.

> The goal of the Combined License applicant's O-RAP is to maintain reliability consistent with the overall safety goals and to maintain the capability to perform safety-related functions. Individual component reliability values are expected to change throughout the course of plant life because of aging and changes in suppliers and technology. Changes in individual component reliability values are acceptable as long as overall plant safety performance is maintained within the NRC-established PRA safety goals and deterministic licensing design basis.

The NRC staff finds that the objectives outlined in DCD Tier 2, Section 17.4.6 are consistent with the objectives described in SECY-95-132 and the acceptance criteria in draft SRP Section 17.4. Therefore, these objectives are acceptable.

17.4.7 D-RAP Phases

17.4.7.1 D-RAP Phase I—SSC Identification and Prioritization

The staff noted several areas where the D-RAP results for the AP1000 and the previously reviewed and approved AP600 design differed. In letters to the applicant dated September 19, 2002, and May 20, 2003, the NRC staff requested additional information on the D-RAP SSC identification results for the AP1000 design in order to evaluate these differences. The NRC staff evaluated the results for the AP600 and AP1000 D-RAP programs and concluded that the applicant adequately justified the differences. The details of the NRC staff evaluation follow.

The staff reviewed the applicant's basis for identification and prioritization of risk-significant SSCs within the scope of the D-RAP for the AP1000. In a revision of DCD Tier 2, Table 17.4-1, the applicant provided expert panel, engineering judgment, and importance measure information on the rationale for including certain SSCs within the scope of D-RAP. The NRC staff found that the probabilistic, deterministic, and engineering judgment information found in DCD Tier 2, Table 17.4-1 was comprehensive and complete. However, in comparing the scope of the AP1000 D-RAP program with the previously approved AP600 D-RAP program, the staff noted several differences. For example, the AP1000 D-RAP included equipment, such as the CAS air compressor transmitter, the IRWST vents, and feedwater isolation valves, that was not included in the AP600 D RAP program. Therefore, in RAI 260.002, the NRC staff requested additional information on the identification and prioritization of risk-significant SSCs within the scope of the D-RAP for the AP1000 design.

In the response to RAI 260.002, the applicant provided the NRC staff with a comprehensive list of differences between the risk achievement worth (RAW) and risk reduction worth (RRW) values for the AP600 and AP1000 design. The NRC staff reviewed the list of differences between the RAW and RRW between the two plants and found that it appropriately identified SSCs within the scope of the D-RAP for the AP1000 design. The NRC staff also reviewed information in the AP1000 PRA, Chapter 50, which contained all the RAW and RRW importance measure values for individual SSCs. This PRA information also was used to determine the list of risk-significant SSCs within the scope of the D-RAP.

On the basis of the information noted above, the NRC staff found that the methodology used to identify SSCs included in the D-RAP in DCD Tier 2, Section 17.4.1, is consistent with the description of SSCs included in the D-RAP in SECY-95-132 and draft SRP Section 17.4. Therefore, RAI 260.002 is resolved.

In RAI 260.003, the NRC staff requested additional information on (1) the passive containment cooling and normal heat-removal functions that were added to the AP1000 design, (2) changes in I&C terminology in the AP1000 design, and (3) changes in the PCS recirculation motor-operated valves (MOVs) functions and valve position. The evaluation of the basis for these changes follows:

- Addition of PCS and Normal Residual Heat Removal Functions to the AP1000 Design

  In DCD Tier 2, Section 17.4.1, the NRC staff identified two system functions that were added to the AP1000 D-RAP—(1) the PCS and MOV drain function for evaporative cooling of the containment shell during design-basis accidents, and (2) the RNS function. The NRC staff evaluated the changes in the risk ranking for these two functions and found that inclusion of these functions in the D-RAP for the AP1000 design was consistent with the applicant's D-RAP methodology.

- Changes in Instrumentation and Control Terminology

  In the AP600 design, the scope of the D-RAP included the protection and monitoring system (PMS) actuation hardware, the ESF actuation, and protection logic cabinets. For the AP1000 design, the PMS actuation hardware, the ESF actuation, and protection logic cabinets were removed from the scope of the D-RAP. The NRC staff requested that the applicant provide additional information stating why it removed these cabinets from the scope of the D-RAP.

  In a revision to DCD Tier 2, Section 17.4.1, the applicant added the PMS actuation hardware to incorporate changes in I&C system terminology that were made to DCD Tier 2, Chapter 7. Therefore, the scope of the hardware covered by the AP1000 D-RAP is acceptable.

- Changes in Passive Core Cooling System Containment Recirculation MOV Function and Normal Valve Position

  In the AP600 design, the MOVs in the passive core cooling system recirculation lines have a safety function for automatic opening to provide core cooling. Because of the safety significance of this function, these MOVs were within the scope of the D-RAP for the AP600 design.

  Although a previous revision of DCD Tier 2, Section 6.3.2.1.3, "Safety Injection During Loss of Coolant Accidents," indicates that the MOVs in each passive core cooling recirculation line automatically open to provide core cooling, the NRC staff found that these valves were not within the scope of the D-RAP for the AP1000 design.

In response to RAI 260.003c, the applicant issued a revision to DCD Tier 2, Section 6.3.2.1.3, to clarify that these MOVs are normally open and do not have a safety function to open automatically. On the basis of this change in the normal position of these valves, the NRC staff concludes that the applicant's determination that these passive core cooling MOVs do not need to be within the scope of the AP1000 D-RAP is acceptable.

In DCD Tier 1, Section 3.7, "Design Reliability Assurance Program," the staff found that the list of risk-significant components in the inspection, test analyses, and acceptance criteria (ITAAC) DCD Tier 1, Table 3.7-1, "Risk Significant Components," was not updated to include all risk-significant SSCs from the list of risk-significant SSCs identified in Tier 2, Table 17.4-1, "Risk-Significant SSCs within the Scope of D-RAP." Specifically, the list of risk-significant components in DCD Tier 1, Table 3.7-1 should include the following:

- compressed and instrument air system (CAS) air compressor transmitter
- passive containment cooling system (PCS) diverse third motor-operated drain isolation valve function
- in-containment refueling water storage tank (IRWST) vents
- normal residual heat removal (RNS) valve V055 function
- main feedwater isolation valves

As discussed in Section 17.4 of this report, the staff determined that DCD Tier 2, Table 17.4-1 contains an acceptable list of risk-significant SSCs under the scope of the D-RAP. In DCD Tier 2, Table 17.4-1, the applicant also removed the automatic open function of the safety-related passive core cooling condensate sump recirculation valves from the D-RAP for the AP1000 design; DCD Tier 1, Table 3.7-1 should reflect this. This was identified as DSER Open Item 14.3.2-15.

On July 8, 2003, Westinghouse provided the following response to Open Item 14.3.2-15. Westinghouse stated that on the basis of the review of DCD Tier 2, Table 17.4-1 and DCD Tier 1, Table 3.7-1, it had the following comments:

- The PRA importance of the CAS air compressor pressure transmitter had been reevaluated. Based on the current AP1000 PRA, this instrument just meets the D-RAP selection criteria (RAW, RRW) for large release frequency, although it does not meet the D-RAP selection criteria for core damage frequency. Furthermore, it has been determined that there are conservatisms in the PRA that have resulted in the overestimation of RAW/RRW values for this instrument. These conservatisms result from the failure to model some plant features that would have reduced the PRA importance of this instrument. Based on this reevaluation, the D-RAP tables in the DCD and the ITAAC should no longer list this instrument. Therefore, Westinghouse removed it from DCD Tier 2, Table 17.4-1 and has not added it to DCD Tier 1, Table 3.7-1.

The NRC staff requested that Westinghouse add further information to this response concerning equipment that was not modeled in the PRA which would reduce the risk importance of the air compressor pressure transmitter. Westinghouse agreed to add information concerning instrument air bottles used to control air-operated valves in the feedwater system which would reduce the risk importance of the air compressor pressure transmitter.

- Westinghouse agreed to add the following equipment to DCD Tier 1, Table 3.7-1:
  - IRWST vents
  - main feedwater isolation valves

- Westinghouse stated that it does not need to add the third PCS water drain valve to DCD Tier 1, Table 3.7-1 because the valve already exists in the table. Three valves are listed under the passive containment cooling water storage tanks drain isolation valves (PCS-PL-V001A/B/C). The C valve is the diverse third drain valve.

- Westinghouse agreed that it should also add RNS valve V055 to the table. However, as indicated in DCD Tier 2, Section 17.4-1, the RNS also requires other RNS MOVs to allow it to provide RCS makeup following actuation of the automatic depressurization system (ADS), including the following:
  - V011 RNS discharge containment isolation
  - V022 RNS actuation containment isolation
  - V055 RNS suction from the spent fuel cooling system cask loading pit
  - V062 RNS suction from the in-containment refueling water storage tank

- Westinghouse agreed that it should remove the passive core cooling system containment recirculation MOVs (PXS-PL-V117A/B) from DCD Tier 1, Table 3.7-1, because they had been removed from DCD Tier 2, Table 17.4-1.

- The review by Westinghouse also indicated that it should make the following additional changes to DCD Tier 1, Table 3.7-1:
  - add chemical and volume control system makeup pump suction and discharge check valves
  - add inverters and battery chargers for the 24-hour batteries
  - add reactor vessel insulation water inlet and steam vent devices
  - add reactor cavity door damper
  - add service water cooling tower fans

- add low-capacity chilled water subsystem
- add standby diesel generator room cooling fans
- add fuel assemblies
- remove passive core cooling system valves PCS-PL-V125A/B from the in-containment refueling water storage tank injection squib valve group because these valves are not squibs, and V123A/B and V125A/B lists the four squibs in these lines

The NRC staff concluded that the Westinghouse response appropriately identified all risk-significant SSCs that should be within the scope of the D-RAP; however, the NRC staff noted that different equipment identification nomenclature between DCD Tier 2, Table 17.4-1, and DCD Tier 1, Table 3.7-1, made it difficult for the NRC staff to identify like components in each table. Westinghouse stated that it would add the risk-significant component tag number for each component to DCD Tier 2, Table 17.4-1 so that the nomenclature in the two tables is the same. In a revision to DCD Tier 2, Table 17.4-1, Westinghouse added the appropriate nomenclature to both tables. The NRC staff found this to be acceptable. Therefore, this part of Open Item 14.3.2-15 is resolved.

In addition, the NRC staff asked Westinghouse to verify that all of the risk-significant SSCs identified in DCD Tier 2, Table 17.4-1, match all of the risk-significant components in DCD Tier 1, Table 3.7-1. In a revision to DCD Tier 2, Table 17.4-1, and DCD Tier 1, Table 3.7-1, the NRC staff verified that the component lists in the two tables were identical. Therefore, this part of Open Item 14.3.2-15 is resolved.

The NRC staff also noted that Westinghouse needed to add the uninterruptible power supply (UPS) Distribution Panels, EDS1-EA-1 and EDS2-EA-1, to the AP1000 D-RAP. The NRC staff determined that these components have RAW values equivalent to UPS Distribution Panels EDS1-EA-14 and EDS2-EA-14. Therefore, the AP1000 D-RAP must include EDS1-EA-1 and EDS2-EA-1. In a revision to DCD Tier 1, Table 3.7-1, "Risk Significant Components," and Tier 2, Table 17.4-1, "Risk Significant SSCs Within the Scope of D-RAP," Westinghouse added UPS Distribution Panels EDS1-EA-1 and EDS2-EA-1 to the two tables. Therefore, this part of Open Item 14.3.2-15 is resolved. Therefore, Open Item 14.3.2-15 is resolved.

The NRC staff determined that the changes in the scope of equipment in the D-RAP for the AP1000 design is consistent with implementation of the D-RAP SSC identification and prioritization methodology in SECY-95-132 and draft SRP Section 17.4. Therefore, D-RAP Phase I activities are acceptable.

17.4.7.2 D-RAP Phase II

- Development of Recommended Plant Maintenance and Monitoring Activities

  In a previous revision of DCD Tier 2, Section 17.4.1, the applicant stated that the D-RAP, as shown in DCD Tier 2, Figure 17.4-1, is implemented in three phases. The first phase, design certification, defines the overall structure of the AP1000 D-RAP and implements the aspects of the program that apply to the design process. During this phase, risk-significant SSCs are identified for inclusion in the program by using probabilistic, deterministic, and other methods. Phase II, postdesign certification, develops component maintenance recommendations for the plant's operation and maintenance activities for identified SSCs. The third phase is the site-specific phase, which introduces the plant's site-specific SSCs to the D-RAP process. It is the applicant's position that the designer performs Phases I and II. The COL applicant is responsible for Phase III.

  In a previous revision of DCD Tier 2, Section 17.4.7.2, "D-RAP Phase II," the applicant stated that "during Phase II of the D-RAP, maintenance assessments and recommendations are developed to enhance reliability of the plant risk-significant components."

  In RAI 260.004, the NRC found that it is not appropriate for the applicant to state that it will complete Phase II, postdesign certification, following issuance of a design certification for the AP1000 design. The applicant should not have postdesign certification issues in the DCD for the AP1000 design. The design certification applicant or the COL applicant should complete this activity. The NRC asked the applicant to provide additional information to clarify the design certification applicant's or the COL applicant's additional responsibilities for completion of Phase II activities.

  In a revision of DCD Tier 2, Section 17.4.1, the applicant revised paragraph 2 to state that, "Phase I is performed by the designer. Phases II and III are completed by the Combined License applicant." Westinghouse also revised DCD Tier 2, Section 17.4.6, paragraph 2, to state the following:

  > Development of maintenance assessments and recommendations for D-RAP (Phase II) and the site-specific portion of the D-RAP (Phase III) are the responsibility of the Combined License applicant. The Combined License applicant is responsible for submitting its maintenance recommendations (Phase II) and site specific (Phase III) D-RAP organization description to the NRC.

  On the basis of this revised approach for maintenance recommendations on risk-significant SSCs, described in DCD Tier 2, Sections 17.4.1 and 17.4.7.2, and in accordance with the guidance in SECY-95-132 and the acceptance criteria in SRP 17.4, the NRC staff finds that the design certification applicant's approach for developing recommended maintenance and monitoring activities is acceptable. On the basis of this revision to the DCD, RAI 261.004 is resolved.

- Dominant Failure Modes and Reliability and Availability Data

  In RAI 260.005a, the NRC staff noted that DCD Tier 2, Section 17.4.7.2.1 did not clearly specify where the design certification application contained cross-reference information for the PRA assumptions for dominant failure modes and for reliability and availability data. The NRC staff asked Westinghouse to add the cross-references in DCD Tier 2, Section 17.4.7.2.1. In a revision of DCD Tier 2, Section 17.4.7.2.1, Westinghouse added the appropriate cross-references as noted on each of the three items listed below. In a revision to DCD Tier 2, Section 17.4.7.2.1, Westinghouse stated that to support the COL applicant's D-RAP Phase II and Phase III and O-RAP, it will provide the following information:

  - the list of risk-significant SSCs identified during the design phase (DCD Tier 2, Table 17.4-1)

  - the PRA assumptions for component unavailability and failure data (Chapter 32 of the AP1000 PRA)

  - the analyses performed for components identified as major contributors to total risk, with dominant failure modes identified and prioritized (major contributors to total risk identified in Chapter 50 of the AP1000 PRA, and the analyses of the respective systems and associated components in DCD Tier 2, Table 17.4-1 described in Chapters 8 and 20 of the AP1000 PRA; suggested means and prevention or mitigation of these failure modes that form the basis for the plant surveillance, testing, and maintenance programs)

  The NRC staff finds that the references noted in DCD Tier 2, Sections 17.4.7.2 and 17.4.7.2.1, for D-RAP Phase II meet the guidance in SECY-95-132 and the acceptance criteria in draft SRP Section 17.4. Therefore, D-RAP Phase II activities are acceptable, and RAI 260.005a is resolved. This is also a COL action item in Section 17.5 of this report.

17.4.7.3 D-RAP Phase III

In DCD Tier 2, Section 17.4.7.3, Westinghouse stated the following:

> Site specific activities of the D-RAP are the responsibility of the Combined License applicant. [DCD Tier 2,] Figure 17.4-1 shows these activities in the Phase III area of the figure. At this stage, the D-RAP package is modified or appended based on considerations specific to the site.

> The COL applicant will need to establish the PRA importance measures, the expert panel process, and other deterministic methods to determine the site-specific list of SSCs under the scope of RAP.
>
> The Combined License applicant would benefit from using the Phase I and II processes as a guide during this phase of the program. It is the responsibility of the Combined License applicant to ensure its Expert Panel is composed of personnel knowledgeable in the systems, operations, and maintenance of a plant, and that these personnel should have the breadth of experience necessary to perform the site-specific SSC selections and evaluations for the RAP.

On the basis of the above, the NRC staff agreed that D-RAP Phase III is appropriately identified as a COL applicant activity. This is a COL action item in Section 17.5 of this report. This activity also meets the guidance in SECY-95-132 and the draft SRP Section 17.4. Therefore, DCD Tier 2, Section 17.4.7.3, is acceptable.

17.4.7.4 D-RAP Implementation

In a revision of DCD Tier 2, Section 17.4.7.4, "D-RAP Implementation," Westinghouse stated the following:

> The following is an example of a system that was reviewed and modified under the D-RAP, Phase I and II. The design and analytical results presented here are intended as an example and do not reflect the current AP1000 design.

In DCD Tier 2, Section 17.4.7.4, Westinghouse provided an example of D-RAP implementation using the ADS as a selection of components that are in the D-RAP for the AP1000 design. In RAI 260.005b, the NRC staff determined that the wording in the second sentence of the first paragraph in DCD Tier 2, Section 17.4.7.4, was confusing. In a revision to DCD Tier 2, Section 17.4.7.4, Westinghouse revised the paragraph to state the following:

> The following is an example of a system that was reviewed and modified under the D-RAP, Phase I. The design and analytical results presented here are intended as an example.

The NRC staff finds that this change is acceptable. The NRC staff also finds that the ADS example is appropriate for the AP1000 implementation of the D-RAP. Therefore, DCD Tier 2, Section 17.4.7.4, is acceptable, and RAI 260.005b is resolved.

17.4.8 Glossary of Terms

In DCD Tier 2, Section 17.4.8, "Glossary of Terms," Westinghouse added the abbreviation "RTNSS" to the list. The NRC staff determined that this section contained all the necessary and appropriate terms used in the D-RAP. Therefore, DCD Tier 2, Section 17.4.8 is acceptable.

17.4.9 Conclusions

On the basis of the NRC staff's review and evaluation of DCD Tier 2, Section 17.4, the NRC staff concludes that the D-RAP for design certification of the AP1000 design is consistent with the guidance provided in SECY-95-132 and draft SRP Section 17.4. Therefore, the D-RAP is acceptable.

17.5 Combined License Information Items

In an effort to ensure that the COL applicant accomplishes the COL action items identified in DCD Tier 2, Section 17.5 and associated with the D-RAP and O-RAP, in a manner consistent with the guidance in SECY-95-132, the NRC asked the applicant to provide a COL action item to reflect conformance with SECY-95-132 guidance. This was identified as DSER Open Item 17.5-1.

In a revision to DCD Tier 2, Section 17.5, Westinghouse added the following:

> This program will address failures of non-safety-related, risk-significant SSCs that result from design and operational errors in accordance with SECY-95-132, Item E.

On the basis of the information in revised DCD Tier 2, Section 17.5, DSER Open Item 17.5-1 is resolved.

In DCD Tier 2, Section 17.5, "Combined License Information Items," Westinghouse describes the following COL action items (note that the NRC staff action item number follows each Westinghouse item):

> The Combined License applicant or holder will address its design phase Quality Assurance program, as well as its Quality Assurance program for procurement, fabrication, installation, construction, and testing of structures, systems and components in the facility. The Quality Assurance program will include provisions for seismic Category II structures, systems and components. This is COL Action Item 17.5-1.
>
> The COL applicant or holder will establish PRA importance measures, the expert panel process, and the other deterministic methods to determine the site-specific list of SSCs under the scope of RAP. This is COL Action Item 17.5-2.
>
> The Combined License applicant is responsible for integrating the objectives of the O-RAP into the Quality Assurance Program developed to implement 10 CFR [Part] 50, Appendix B. This program will address failures of non-safety-related, risk-significant SSCs that result from design and operational errors in accordance with SECY-95-132, Item E. This is COL Action Item 17.5-3.

The Combined License applicant or holder will address its Quality Assurance program for operations. This is COL Action Item 17.5-4.

The following activities are represented in [DCD Tier 2,] Figure 17.4-1 as "Plant Maintenance Program."

The Combined License applicant is responsible for performing the tasks necessary to maintain the reliability of risk-significant SSCs. Reference 8 [Lofgren, E.V., Cooper, et al., "A Process for Risk-Focused Maintenance," NUREG/CR-5695, March 1991] contains examples of cost-effective maintenance enhancements, such as condition monitoring and shifting time-directed maintenance to condition-directed maintenance.

The Maintenance Rule (10 CFR 50.65) is relevant to the Combined License applicant's maintenance activities in that it prescribes SSC performance-related goals during plant operation. This is COL Action Item 17.5-5.

In addition to performing the specific tasks necessary to maintain SSC reliability at its required level, the O-RAP activities include:

- Reliability data base—Historical data available on equipment performance. The compilation and reduction of this data provides the plant with source of component reliability information.

- Surveillance and testing—In addition to maintaining the performance of the components necessary for plant operations, surveillance and testing provides a high degree of reliability for the safety-related SSCs.

- Maintenance plan—This plan describes the nature and frequency of maintenance activities to be performed on plant equipment. The plan includes the selected SSCs identified in the D-RAP.

This is COL Action Item 17.5-6.

18. HUMAN FACTORS ENGINEERING

The staff of the U.S. Nuclear Regulatory Commission (NRC) reviewed Chapter 18, "Human Factors Engineering," of the AP1000 Design Control Document (DCD) Tier 2, based on current regulatory requirements and NRC guidance, including the criteria of NUREG-0711, "Human Factors Engineering Program Review Model," Revision 1. This NRC technical report provides additional guidance for reviewing those aspects of the AP1000 Human Factors Engineering (HFE) Program not fully addressed by previously available documents. The staff's review also included aspects of the organizational structure of the applicant and its training and plant procedures. Information concerning these aspects of the AP1000 design are contained in DCD Tier 2, Sections 13.1, "Organizational Structure of the Applicant"; 13.2, "Training"; and 13.5, "Plant Procedures"; as well as additional HFE materials submitted by the applicant.

Section 18.1 of this report provides an overview of the general methodology and review criteria used in the staff's evaluation, including the HFE program review model. Sections 18.2 through 18.13 of this report describe the results of the staff's review of the following HFE topics, the first 12 of which are the elements of NUREG-0711:

(1) HFE program management (Section 18.2)
(2) operating experience review (OER) (Section 18.3)
(3) functional requirements analysis and allocation (Section 18.4)
(4) task analysis (Section 18.5)
(5) staffing and qualification (Section 18.6)
(6) human reliability analysis (HRA) (Section 18.7)
(7) human-system interface (HSI) design (Section 18.8)
(8) procedure development (Section 18.9)
(9) training program development (Section 18.10)
(10) human factors verification and validation (V&V) (Section 18.11)
(11) design implementation (Section 18.12)
(12) human performance monitoring (Section 18.13)
(13) minimum inventory (Section 18.14)

The last requirement, minimum inventory, addresses the challenges posed by the lack of control room detail provided in applications for advanced reactor designs.

In Section 18.15 of this report, the staff provides a summary of the review findings and overall conclusions; Section 18.16 of this report identifies Chapter 18-related Tier 2* information items.

18.1 <u>Review Methodology</u>

18.1.1 Human Factors Engineering Review Objective

The overall purpose of the HFE review is to ensure the following:

- The applicant has satisfactorily integrated HFE into the AP1000 development, design, and evaluation.

- The AP1000 HFE products (e.g., human-system interfaces, procedures, and training) reflect "state-of-the-art human factors principles" (see Title 10, Section 50.34(f)(2) of the Code of Federal Regulations (10 CFR 50.34(f)(2), as required by 10 CFR 52.47(a)(1)(ii)), and satisfy all other appropriate regulatory requirements stated in Title 10 of the Code of Federal Regulations.

- The AP1000 human-system interfaces, procedures, and training make possible safe, efficient, and reliable performance of operation, maintenance, test, inspection, and surveillance tasks.

18.1.2 Review Criteria

The review criteria used to assess the AP1000 HFE Program were primarily based on the criteria of NUREG-0711. In addition, the review criteria included current regulatory requirements established in 10 CFR 50.34(f), 10 CFR 50.34(g), 10 CFR 52.47, and the HFE review guidance contained in NUREG-0800, "Standard Review Plan," and NUREG-0700, "Human System Interface Design Review Guideline." For selected review topics, the staff used guidance from other NRC documents as well. These documents are identified in the appropriate review sections of this report.

18.1.3 Procedure for Reviewing AP1000 Human Factors Engineering

The DCD Tier 2 responses to the staff's requests for additional information (RAIs) and several related Westinghouse topical reports describe HFE for the Westinghouse AP1000 design. These materials describe a design and implementation process for an AP1000 HFE Program, as well as some preliminary products of that process. The staff issued 50 HFE-related RAIs, the majority of which were of a clarifying nature and were satisfactorily addressed by the applicant. These do not need to be reiterated in this report. However, this report does include the applicant's responses to substantive HFE-related RAIs.

At the time the staff prepared this report, the applicant had not completed the final design of the AP1000 HFE Program. The staff used the criteria identified in Section 18.1.2 of this report as the basis for its review of the AP1000 HFE Program. The design certification evaluation is based on a design and implementation process plan proposed by the applicant that describes the HFE program elements required to develop the detailed design. The staff's review was also based on the applicant's partial completion of the NUREG-0711 criteria. Generally, NUREG-0711 is used by the staff to conduct the following three types of reviews of applicant submissions:

(1) programmatic review
(2) implementation plan review
(3) complete element review

The staff conducted all three types of reviews of the AP1000 design. In terms of a programmatic review, DCD Tier 2 does not include detailed methodologies; therefore, detailed evaluations using NUREG-0711 acceptance criteria are beyond the scope of the staff's review for design certification. At a programmatic review level, the staff used the criteria in NUREG-0711 to determine whether the program provides a top-level identification of the substance of each review criterion such that after design certification, the criteria will be developed by the combined license (COL) applicant into a detailed implementation plan. The programmatic review provides assurance that the implementation plan will address all NUREG-0711 review criteria. The AP1000 Tier 1 information describes the commitment to develop such a detailed implementation plan, including the appropriate inspections, tests, analyses, and acceptance criteria (ITAAC). The staff will review this plan in the context of specific COL applications. The ITAAC are also needed for completing the implementation plan and providing the results to the staff for review.

For the staff to perform an implementation plan review, the applicant's submission should describe the proposed methodology in sufficient detail for the staff to determine if the methodology will lead to products that meet the NUREG-0711 acceptance criteria for the particular program element. An implementation plan review affords the applicant the opportunity to obtain staff review and concurrence on the full method before design certification. The actual completion of the plan will then likely take place after design certification. Such a review is desirable from the staff's perspective because it presents the opportunity to resolve methodological issues and provide input early in the analysis or design process. The staff's concerns can be addressed more easily at that time when the applicant's effort is completed. While some implementation plans can be reviewed on their own merits, the staff may request a sample analysis that demonstrates the application of the methodology and its results. The ITAAC are needed to complete the implementation plan for submission to the staff for review. Section 14.3 of this report presents the staff's evaluation of the AP1000 ITAAC.

A complete element review can only be performed when the finished products (e.g., main control room (MCR) design) are available for the staff to evaluate and the applicant has submitted the results summary report(s). A results summary report provides the results of the applicant's efforts to address an element of the NUREG-0711 review criteria. The staff will use the report as the main source of information for assessing compliance with the review criteria.

In addition to the NUREG-0711 elements, the staff reviewed the applicant's minimum inventory (Section 18.14) of controls, displays, and alarms (CDAs) required to adequately implement emergency operating procedures (EOPs) and address critical and risk-important operator actions identified in the AP1000 probabilistic risk assessment (PRA). The staff also reviewed the applicant's emergency response guidelines (ERGs) applicable to the AP1000 design.

The remaining sections of this chapter present a review of each topic using the following four subheadings:

(1) Objectives: This section describes the overall review objectives for the topic.

(2) Methodology: While the general review methodology is described in this section, specific review topics may have unique aspects to the review methodology. Such details are provided in the methodology section for a specific topic. This section identifies the specific Westinghouse material used in the safety determination (e.g.,

DCD sections or RAI responses) and the documents used to support the technical basis of the evaluation (e.g., NUREG-0711 or NUREG-0700).

(3) Results: The results section is divided into the following two components:

- Criterion: This component identifies the criterion being evaluated which is usually based on NUREG-0711 or a similar document issued by the NRC.
- Evaluation: This component describes the staff's evaluation of the materials submitted by the applicant for their acceptability with respect to the review criterion. The basis for the assessment is documented, including documented materials and discussions with the applicant that may have resulted in modifications or clarifications to materials submitted by Westinghouse that led to the assessment. Any questions, additional information, or discrepancies that were identified are documented in the evaluation.

(4) Conclusions: This section summarizes the staff's findings for the review topic.

18.2 Element 1: Human Factors Engineering Program Management

18.2.1 Objectives

The objective of the staff's review of the AP1000 HFE program management is to ensure that the applicant has described an HFE Program that addresses the guidance and review criteria contained in NUREG-0800, Chapter 18.0, "Human Factors Engineering," and that it will be implemented by a qualified HFE design team. The HFE design team should have the responsibility, authority, placement within the organization, and composition to ensure that the design commitment to HFE is achieved. Also, the team should be guided by an HFE program plan to ensure the proper development, execution, oversight, and documentation of the HFE Program. This plan should describe the technical program elements, ensuring that all aspects of the HSI are developed, designed, and evaluated based upon a structured, top-down, systems analysis using accepted HFE principles.

18.2.2 Methodology

18.2.2.1 Material Reviewed

The following Westinghouse documents referenced in DCD Tier 2 were used in this review:

- WCAP-13793, "The AP600 System/Event Matrix," issued June 21, 1994
- WCAP-13957, "AP600 Reactor Coolant Mass Inventory: Function-Based Task Analysis," issued January 31, 1994
- WCAP-14075, "AP600 Design Differences Document for the Development of Emergency Operating Guidelines Report," issued May 20, 1994

Human Factors Engineering

- WCAP-14396, Revision 3, "Man-in-the-Loop Test Plan Description," issued November 27, 2002

- WCAP-14401, Revision 3, "Programmatic Level Description of the AP600 Verification and Validation Plan," issued April 1997

- WCAP-14644, "AP600 Functional Requirements Analysis and Function Allocation," issued October 9, 1996

- WCAP-14645, Revision 2, "Human Factors Engineering Operating Experience Review Report for the AP600 Nuclear Power Plant," issued December 1996

- WCAP-14651, Revision 2, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," issued May 3, 1997

- WCAP-14655, Revision 1, "Designer's Input for the Training of Human Factors Engineering Verification and Validation Personnel," issued August 8, 1996

- WCAP-14690, Revision 1, "Designer's Input to Procedure Development for the AP600," issued June 27, 1997

- WCAP-14694, "Designer's Input to Determination of the AP600 Main Control Room Staffing Level," issued July 31, 1996

- WCAP-14695, "Description of the Westinghouse Operator Decision-Making Model and Function-Based Task Analysis Methodology," issued July 31, 1996

- WCAP-15847, Revision 1, "AP1000 Quality Assurance Procedures Supporting NRC Review of AP1000 DCD Sections 18.2 and 18.8," issued December 2002

- WCAP-15800, Revision 3, "Operational Assessment for AP1000," issued July 2004

- WCAP-15860, Revision 2, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," issued October 2003

Other documents used in this review include:

- Westinghouse Procedure AP-3.1, Revision 2, "AP600 System Specification Documents (SSDs)," issued June 1, 1995

- Westinghouse Procedure AP-3.2, Revision 8, "Change Control for the AP600 Program," issued June 1, 1999

- Westinghouse Procedure AP-3.5, Revision 2, "Design Reviews," issued February 18, 1997

- Westinghouse Procedure AP-3.6, Revision 2, "AP600 Design Criteria Documents," issued March 11, 1994

- Westinghouse Procedure AP-3.7, "Interface Control Document," issued February 8, 1991

- Westinghouse Procedure AP-3.12, Revision 1, "AP600 Engineering Data Base (EDB) Access and Control," issued February 20, 1997

- Westinghouse Procedure AP-3.14, "AP1000 Plant I&C Systems (PI&CS)," issued October 31, 1991

- Westinghouse Procedure AP-7.2, "Control of Subcontractor Submittals," issued March 1, 2002

- NUREG-1512, "Final Safety Evaluation Report Related to Certification of the AP600 Standard Design," issued September 1998

18.2.2.2 Technical Basis

The staff focused its review on an evaluation of the documents submitted by the applicant with respect to the topics and general criteria of Element 2, "HFE Program Management," of NUREG-0711. The staff reviewed the applicant's HFE program management at a complete element review level (i.e., finished products generated by the applicant to demonstrate compliance with this element were available for review using the NUREG-0711 criteria).

18.2.3 Results

This section discusses the results of the staff's evaluation of the AP1000 HFE program management in terms of the general program goals and scope, the HFE design team and organization, HFE process and procedures, HFE issues tracking, and the HFE technical program. For each of these characteristics, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections.

18.2.3.1 General Human Factors Engineering Program Goals and Scope

Criterion 1: HFE Program Goals

Criterion:

The general objectives of this program should be stated in human-centered terms. As the HFE Program develops, the terms should be objectively defined and serve as criteria for test and evaluation activities. Generic human-centered HFE design goals are listed in General Criterion 1 of NUREG-0711, Revision 1.

Evaluation:

The human-centered description is supported throughout DCD Tier 2, Chapter 18, for all phases of the HFE Program as indicated in the following examples:

- DCD Tier 2, Section 18.2, "Human Factors Engineering Program Management," identified the following goal of the human factors engineering program—"to provide the users of the plant operation and control centers effective means for acquiring and understanding plant data and executing actions to control the plant's processes and equipment."
- The process described in DCD Tier 2, Sections 18.4 and 18.8.2, for functional task analysis emphasized the identification of detection, monitoring, decision, and control requirements for crew task performance to support HSI development.
- The verification and validation process described in DCD Tier 2, Section 18.11, focused on the evaluation of user-centered issues (see DCD Tier 2, Figure 18.11-1) that are consistent with NUREG-0711-identified goals, such as crew awareness of plant condition.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Assumptions and Constraints

Criterion:

The applicant should clearly identify the design assumptions and constraints. An assumption or constraint is an aspect of the design, such as a specific staffing plan or the use of specific HSI technology, which is an input to the HFE Program, rather than the result of HFE analyses and evaluations. For example, if a design constraint imposed by a utility requirement (rather than by design analysis) is that the entire plant operation, including emergencies, is to be accomplished by a single operator, that constraint will impact all other human factors analyses, such as allocation of function and workstation design. Specifically, this design constraint would require much greater automation than is typical in commercial nuclear power plants, as well as a single operations console containing all plant monitoring and control function. The staffing design constraint may drive the design without an acceptable HFE rationale, and may negatively impact the integration of plant personnel into the overall plant design. The purpose of this criterion is to make such "design drivers" explicit.

Evaluation:

The DCD Tier 2 addresses the assumptions and constraints of the design by identifying them as inputs to the HFE Program. DCD Tier 2, Section 18.8 describes the overall HFE design and implementation process. This section presents the inputs to the program (e.g., specific system details such as those represented by piping and instrumentation diagrams). (See also DCD Tier 2, Figure 18.11-1.) Assumptions and constraints stem from regulatory guidance, utility groups, and AP1000 plant system design specifications. The DCD Tier 2 provides an overview of the types of requirements associated with each. For example, the utility groups require that a single reactor operator control the major plant functions performed from the MCR during normal plant operations. DCD Tier 2, Section 18.2.1.2 briefly discusses the process of function allocation which is further clarified in WCAP-14644. System engineers make initial allocations based on the operating experience of previous designs.

With respect to control room resources, the inclusion of a wall panel display is an approach to meeting a utility requirement for an integrating overview and mimic display. While alternative approaches are possible, the wall panel approach will be designed and evaluated as part of the AP1000 HFE Program.

The applicant appropriately indicated that while all assumptions and constraints are provisionally treated as requirements, their appropriateness will ultimately be evaluated as part of the HFE design process.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Applicable Facilities

Criterion:

The HFE Program should address the MCR, remote shutdown facility, technical support center (TSC), emergency operations facility (EOF), and local control stations (LCSs).

Evaluation:

DCD Tier 2, Section 18.2.1.3, "Applicable Facilities," indicates that the MCR, TSC, remote shutdown room, operational support center, EOF, and LCSs are included in the AP1000 HFE Program. The COL applicant is responsible for designing the EOF, including specifying a location, in accordance with the AP1000 HFE Program. DCD Tier 2, Section 18.8 indicates that the scope of the HFE Program encompasses the facilities identified in this criterion. The applicant will define the EOF information systems and communications necessary for the plant to interface to the EOF. The design of the facility will be the responsibility of the COL applicant. This is acceptable because the site-specific requirements on the EOF necessitate final design by the COL applicant. However, the presentation of the plant data should be consistent with the HSI design, and the COL applicant's approach must achieve this consistency. This is COL Action Item 18.2.3.1-1.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Applicable Human-System Interfaces, Procedures, and Training

Criterion:

The applicable HSIs, procedures, and training included in the HFE Program should encompass all operations, accident management, maintenance, test, inspection, and surveillance interfaces (including procedures).

Evaluation:

DCD Tier 2, Section 18.2.1.4, "Applicable Human System Interfaces," states that the scope of the HSIs covered by the AP1000 HFE Program includes instrumentation and control (I&C) systems that perform the monitoring, control, and protection functions associated with all modes of plant operation, as well as off-normal, emergency, and accident conditions. The applicant's HFE Program addresses the physical and cognitive requirements of plant personnel involved in the use, control, maintenance, test, inspection, and surveillance of plant systems, including training and procedures.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: Applicable Plant Personnel

Criterion:

Plant personnel who should be included in the HFE Program encompass licensed control room operators, as defined in 10 CFR Part 55, and the following categories of personnel defined in 10 CFR 50.120:

- nonlicensed operator
- shift supervisor
- shift technical advisor
- instrument and control technician
- electrical maintenance personnel
- mechanical maintenance personnel
- radiological protection technician
- chemistry technician
- engineering support personnel

In addition, the HFE Program should also include other plant personnel who perform tasks that are directly related to plant safety.

Evaluation:

In addition to plant personnel defined in 10 CFR Part 55 and 10 CFR 50.120, the applicant identified management and engineering personnel to be within the mission and scope of the HFE Program.

DCD Tier 2, Section 18.2.1.5, "Applicable Plant Personnel," acceptably incorporates the applicable plant personnel that should be addressed by the HFE Program.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.2.3.2 Human Factors Engineering Design Team and Organization

The staff reviewed the responsibility, organizational placement and authority, composition, and staffing of the HFE design team described in DCD Tier 2 to determine whether it acceptably addresses these topics, as defined by NUREG-0711. NUREG-0711 refers to an HFE design team, while the equivalent applicant's organizational unit is called the HSI design team. The two terms are used interchangeably throughout this report.

Criterion 1: Responsibility

Criterion:

The team should be responsible for the following activities with respect to the scope of the HFE Program:

- developing all HFE plans and procedures
- overseeing and reviewing all HFE design
- conducting development, test, and evaluation activities
- initiating, recommending, and providing solutions through designated channels for problems identified in the implementation of the HFE activities
- verifying implementation of team recommendations
- ensuring that all HFE activities comply with the HFE plans and procedures
- scheduling activities and milestones

Evaluation:

In DCD Tier 2, Section 18.2.2, "Human System Interface Design Team and Organization," the function of the HSI design team is described as being part of the AP1000 systems engineering function, having similar responsibilities, authority, and accountability as other segments of the design team. The responsibilities of the HSI design team, outlined in DCD Tier 2, Section 18.2.2.1, include all responsibilities identified by this NUREG-0711 criterion.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Organizational Placement and Authority

Criterion:

The applicant should identify, describe, and illustrate primary HFE organization(s) or function(s) within the organization of the total program (e.g., charts showing organizational and functional relationships, reporting relationships, and lines of communication). When more than one organization is responsible for HFE, the applicant should identify the lead organizational unit responsible for the HFE program plan. The team should have the authority and organizational placement to ensure that all of its areas of responsibility are accomplished, and to identify problems in the implementation of the overall plant design.

Evaluation:

DCD Tier 2, Section 18.2.2.2, "Organizational Placement and Authority," discusses the organization of the HSI design team and its relationship to the AP1000 design organization. DCD Tier 2, Figure 18.2-2 illustrates the organization of the HSI team and its relationship to the AP1000 design organization. The team is comprised of seven design and analysis functions and an Advisors/Reviewers Team. These groups report to an I&C systems manager, who is responsible for the overall HSI design and its integration with the rest of the plant design.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Composition

Criterion:

NUREG-0711 specifies that the HFE design team should have specific expertise in the following areas:

- technical project management
- systems engineering
- nuclear engineering
- control and instrumentation engineering
- architect engineering
- human factors engineering
- plant operations
- computer system engineering
- plant procedure development
- personnel training
- systems safety engineering
- reliability, availability, maintainability, and inspectability engineering

Evaluation:

In DCD Tier 2, Section 18.2.2.3, the applicant provided the disciplines of a multidisciplinary HSI design team which meet the criteria identified in Appendix A of NUREG-0711.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Team Staffing

Criterion:

The applicant should describe team staffing in terms of job descriptions and assignments of team personnel.

Evaluation:

DCD Tier 2, Section 18.2.2.4, "Team Staffing Qualifications," identifies the organization of the HSI design team in terms of functional engineering areas. The applicant provided job descriptions of members of the human systems interface design team. Greater emphasis was placed on the individual's relevant experience to the specific area, rather than on formal education. The professional experience of the HSI design team as a whole was emphasized as an approach to satisfy needed experience and professional qualifications of the team.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.2.3.3 Human Factors Engineering Process and Procedures

Criterion 1: General Process Procedures

Criterion:

The applicant should identify the process through which the team will execute its responsibilities, including procedures for the following:

- assigning HFE activities to individual team members (a)
- governing the internal management of the team (b)
- making management decisions regarding HFE (c)
- making HFE design decisions (d)
- governing equipment design changes (e)
- conducting design team review of HFE products (f)

Evaluation:

DCD Tier 2, Section 18.8.2 describes the programmatic aspects of the design process. The I&C systems function group is responsible for developing the AP1000 I&C, including HSIs, and coordinating and integrating the interfaces with other plant design activities. Design reviews are an integral part of the design process.

Regarding Items 1a and 1b of the NUREG-0711 criterion, procedures address the assignment of HFE activities to individual team members and the internal management of the team. DCD Tier 2, Section 18.2.2.2, discusses the organization of the team (DCD Tier 2, Figure 18.2-2) and its relationship to the overall AP1000 organization. The internal workings of the organization are also described. The key members of the HSI design team consist of an I&C manager, an HSI design function manager, the HSI technical lead, a review team, and the core HSI design team. The technical lead works on the HSI design function and reports to the manager of the HSI design function, who in turn reports to the I&C manager, who ultimately reports to the AP1000 project manager. Section 18.2.2.1 defines these responsibilities. The organization is depicted on DCD Tier 2, Figure 18.2-2, which lists individual technical skills that are related to the project and coordinated by the technical lead. These disciplines include systems engineering, nuclear engineering, I&C engineering, human factors, plant operations, computer systems, systems engineering, and maintainability. Items 1c and 1d of NUREG-0711 address management and design decisions relative to HFE. These topics are addressed in DCD Tier 2, Section 18.2.2.2, which covers the roles of the various managers associated with the project (e.g., AP1000 project manager of instrumentation and control systems, manager of human systems interface design).

The DCD Tier 2 indicates that system specification documents (SSDs) detail human factors and HSI requirements by including task requirements, information requirements, and operations requirements. They should also provide a mechanism to document and track HFE requirements. A functional requirements document is developed for each HSI resource (e.g., alarm system and wall panel information system). Design specification documents detail design specifications and integration. The applicant indicated that design changes are controlled through a design configuration change control process using a method of design change proposals to initiate and document a proposed design change. Design reviews by a multi-disciplined review team provide a method of design verification. Hence, Items 1c and 1f are addressed. This information provides an acceptable indication of how HFE information is documented and coordinated. WCAP-15847, Revision 1, contains relevant procedures related to the HFE process.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Process Management Tools

Criterion:

The applicant should identify tools and techniques (e.g., review forms) to be used by the team to verify they fulfill their responsibilities.

Evaluation:

DCD Tier 2, Section 18.2.3.1 indicates that design change proposals are tracked to closure through a design issues tracking database. DCD Tier 2, Section 18.2.4, "Human Factors Engineering Issues Tracking," indicates that the database receives issues to track from several sources, including design reviews. The manager responsible for each system enters design review action items into the database and tracks them. A design issues tracking system database is an acceptable tool because it documents and tracks design issues that are identified during the plant design process. HFE checklists are included in the design review package provided for each design review. An action item is defined for each issue identified through the use of the checklist.

Relevant information related to the HFE process management tools is contained in WCAP-15847, Revision 1. The staff reviewed this topical report and finds that it acceptably incorporates the items required by this criterion.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Integration of Human Factors Engineering and Other Plant Design Activities

Criterion:

The applicant should identify the integration of design activities, including inputs from other plant design activities to the HFE Program, and outputs from the HFE Program to other plant design activities. The applicant should also address the iterative nature of the HFE design process.

Evaluation:

DCD Tier 2, Section 18.2.3.3 describes how the AP1000 HFE design process provides for the integration of HFE activities with other design groups. DCD Tier 2, Figure 18.2-3, "Overview of the AP1000 Human Factors Engineering Process," depicts organization and design process flows that include iterative and feedback features. DCD Tier 2, Section 18.8 discusses the integration of the applicant-designed components of the HSI with those portions that are site specific and the responsibility of the COL applicant. This includes areas such as the operations support center and the EOF. The staff concludes that the applicant has acceptably addressed the integration of HFE and other plant design activities.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Human Factors Engineering Program Milestones

Criterion:

HFE program milestones should be identified to permit evaluation of the effectiveness of the HFE effort at critical check points and to show their relationship to the integrated plant sequence of events. A relative schedule should be available to allow the NRC staff to review HFE program tasks, including the relationships among HFE elements and activities, products, and reviews.

Evaluation:

DCD Tier 2, Section 18.2.5 addresses HFE program milestones; DCD Tier 2, Figure 18.2-3 provides an overview of HFE tasks showing relationships between the HFE elements, activities, products and reviews. The activities are presented in approximate chronological order. Internal design reviews are performed by the applicant design team at various points throughout the design process.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: HFE Documentation

Criterion:

HFE documentation items should be identified and briefly described, along with the procedures for retention and access.

Evaluation:

DCD Tier 2, Section 18.2.3.4 addresses the criterion for HFE documentation. The applicant discussed the purpose of different types of HFE documentation (e.g., procedures and documents) with selected procedures addressing the aspects of access and retention. DCD Tier 2, Sections 18.3 through 18.12 provide information on the types of documents that are generated as part of the AP1000 HFE Program. Additional documentation addressing this criterion is provided in WCAP-15847, Revision 1.

Based on this information, the finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 6: Subcontractor HFE Efforts

Criterion:

The applicant should include HFE requirements in each subcontract and verify the subcontractor's compliance with HFE requirements periodically.

Evaluation:

DCD Tier 2, Section 18.2.3.5, "Human Factors Engineering in Subcontractor Efforts," indicates that HFE and HSI requirements are provided to subcontractors through the applicant's engineering documents, including design criteria and system specification documents. WCAP-15847, Revision 1, contains the AP1000 program procedure matrix which identifies the procedures that apply to subcontractor design organizations. In addition, DCD Tier 2, Section 17.3, specifies quality assurance requirements that are associated with subcontractor HFE design efforts.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.2.3.4 Human Factors Engineering Issues Tracking

Criterion 1: Availability

Criterion:

A tracking system should be available to address human factors issues that are known to the industry, as defined in Element 3, "Operating Experience Review," of NUREG-0711, and identified throughout the life cycle of the HFE/HSI design, development, and evaluation. Issues are those items that need to be addressed at some later date, and thus need to be tracked to ensure that they are not overlooked. The applicant may adapt an existing tracking system to serve this purpose.

Evaluation:

DCD Tier 2, Section 18.2.4 discusses the applicant's HFE issues tracking system. Tracking of HFE issues is accomplished within the framework of the overall plant design process. The design issues tracking system database is used to track AP1000 design issues to resolution, including HFE issues. The design review process also provides input into the design issues tracking system. HFE design issues directly associated with the AP1000 HSIs and the operation and control centers (e.g., the MCR, remote shutdown workstation, and TSC) are also entered into the design issues tracking system database. The applicant's AP1000 project manager is responsible for the maintenance and documentation of the design issues tracking system. For each issue entered into the database, a "responsible engineer" is assigned to resolve the issue.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Method

Criterion:

The method should document and track HFE issues from identification until elimination or reduction to an acceptable level.

Evaluation:

DCD Tier 2, Section 18.2.4 describes a database for tracking issues. The tracking system enables the documentation and tracking of issues that need to be addressed at some later date. For each design issue including all HFE issues, entered into the database, the actions taken to address the issue and the final resolution are documented.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Documentation

Criterion:

Each issue or concern that meets or exceeds the threshold established by the design team should be entered into the system when first identified. Similarly, each action taken to eliminate or reduce the issue or concern should be thoroughly documented. The final resolution of each issue or concern should be documented in detail, along with information regarding design team acceptance.

Evaluation:

DCD Tier 2, Section 18.2.3.4 discusses the HFE documentation for the AP1000 design. The AP1000 HFE design process has procedures to address documentation for the AP1000, including procedures for document preparation, review, retention, access, and configuration control. A design configuration control process is used to control and implement proposed design changes. The applicant maintains design change proposals in a database that is used to track the status of each design change proposal from initiation through implementation and closure.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Responsibility

Criterion:

When an issue is identified, the tracking procedures should describe individual responsibilities for issue logging, tracking, and resolution, as well as resolution acceptance.

Evaluation:

DCD Tier 2, Section 18.2.2.2 identifies the HSI technical lead as the individual responsible for tracking HFE issues to resolution. This section also indicates that the engineer responsible for resolving each issue will be identified in the database. For example, the manager of the system under review is also responsible for resolution of design review issues. The applicant's AP1000 project manager is responsible for the overall maintenance and documentation of the tracking system.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.2.3.5 Human Factors Engineering Technical Program

The evaluation of the HFE technical program, as part of Element 1 of NUREG-0711, addresses scoping, resources, and management details. Actual technical details are addressed in the respective element reviews.

Criterion 1: Plans and Analyses

Criterion:

The general development of implementation plans, analyses, and evaluation for each of the following areas should be identified and described:

- operating experience review
- functional requirements analysis and function allocation
- task analysis
- staffing and qualifications
- human reliability analysis
- human-system interface design
- procedure design
- training design
- human factors verification and validation
- design implementation
- human performance monitoring

Evaluation:

The applicant's technical program, as presented in DCD Tier 2, Chapters 13 and 18, incorporates all of the identified NUREG-0711 elements. DCD Tier 2, Figures 18.2-1, 18.2-2, and 18.2-3 identify the inputs and outputs (documentation) for the major activities of the HFE Program. DCD Tier 2, Section 18.2.5, "Human Factors Engineering Technical Program and Milestones," details the applicant's commitment to perform the AP1000 HFE Program in accordance with the HFE process specified in NUREG -0711.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: HFE Requirements

Criterion:

The applicant should identify and describe the HFE requirements imposed on the design process. The applicant should list the standards and specifications that are sources of HFE requirements.

Evaluation:

Numerous places in DCD Tier 2 address HFE requirements, and the definition of HFE requirements is a major activity of the HFE Program. For example, DCD Tier 2, Section 18.8.6 lists the requirements to be identified in the HFE Program. DCD Tier 2, Section 18.8.1.2 states that guidance documents are provided to designers of the alarm systems, anthropometrics, displays, controls, and computerized procedures. Guidelines for the HSI design are developed for each of the HSI resources to facilitate the standard and consistent application of HFE principles to the AP1000 design. The guidance is contained in a set of standards and conventions guideline documents that tailor generic HFE guidance to the AP1000 HSI design and define the application of those HFE principles.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Facilities and Tools

Criterion:

The applicant should specify HFE facilities, equipment, tools, and techniques, such as laboratories, simulators, and rapid prototyping software, to be used in the HFE Program.

Evaluation:

DCD Tier 2, Section 18.2.3.2, "Process Management Tools," provides a description of a design database and tracking system that is used to facilitate communications across AP1000 design disciplines and organizations. In WCAP-15860, Revision 2, the applicant identifies the use of various tools (e.g., design review checklists, design issues tracking system) to evaluate dynamic task performance. This is further supported by additional detailed descriptions of, for example, simulation scenario design and use, in WCAP-14396, Revision 3.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.2.4 Conclusions

The objective of the HFE program management review is to ensure that the applicant has described an adequate HFE program plan and identified a qualified HFE design team to implement the plan. The plan should describe the technical program elements, ensuring that all aspects of the HSI are developed, designed, and evaluated based on a structured, top-down systems analysis using accepted HFE principles. The staff reviewed the applicant's HFE program management at a complete element review level. Finished products developed by the applicant to complete the element are available for review. For the reasons set forth above, the DCD Tier 2 provides an acceptable basis for a human factors program plan. The applicant has acceptably completed this NUREG-0711 element. The COL applicant referencing the AP1000 certified design is responsible for the execution of an NRC-approved HFE Program. This is COL Action Item 18.2.4-1.

18.3 Element 2: Operating Experience Review

18.3.1 Objective

The objective of the staff's review of the AP1000 OER is to ensure that the applicant has identified and analyzed HFE-related problems and issues encountered in previous designs that are similar to the design under review. By doing so, the applicant can ensure that such issues are not repeated in the development of the current design or, in the case of positive features, that they are included in the design.

18.3.2 Methodology

18.3.2.1 Material Reviewed

The staff used the following Westinghouse documents in this review:

- DCD Tier 2
- WCAP-14645, Revision 2, "Human Factors Engineering Operating Experience Review Report for the AP600 Nuclear Power Plant," issued December 1996

18.3.2.2 Technical Basis

The staff evaluated the applicant's documents with respect to the topics and general criteria of Element 3, "Operating Experience Review," of NUREG-0711. The staff reviewed the applicant's OER at a complete element review level. Finished products submitted by the applicant to complete the element were available for review using NUREG-0711 criteria.

18.3.3 Results

This section presents the results of the staff's review of the applicant's OER, including the scope and the process for analyzing, tracking, and reviewing issues. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections.

18.3.3.1 Scope

Criterion 1: Predecessor Plant and Systems

Criterion:

The OER should include information pertaining to the human factors issues related to the predecessor plant(s) or highly similar plants and plant systems.

Evaluation:

In WCAP-14644, Section 1.4.2, the applicant identified the predecessor plant for the AP600 as "the generic PWR design for currently licensed Westinghouse nuclear power plants." Table 1 illustrates in detail how the critical safety functions for the AP600 are the same as for current Westinghouse PWR plants. The other portions of this topical report illustrate the differences between the predecessor plants and the AP600. Thus, current Westinghouse pressurized-water reactors (PWRs), in general, serve as the predecessor for the AP600 nuclear power plant. Since the AP1000 is similar to the AP600 in its operation, WCAP-14644 is applicable to the AP1000.

In the AP1000 OER, the applicant addressed current Westinghouse PWRs. This is illustrated in WCAP-15800, Revision 3. Further, WCAP-14645, Revision 2, noted in Section 2.0 of the report, includes both Westinghouse and non-Westinghouse PWRs. It also addresses pertinent boiling-water reactor (BWR) issues and a pressurized heavy-water reactor, where applicable to the new design. Thus, the applicant has included information in its OER pertaining to the human factors issues related to both the predecessor plants and highly similar plants and plant systems. Therefore, WCAP-14645, Revision 2, is also applicable to the AP1000.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Recognized Industry HFE Issues

Criterion:

Recognized nuclear power industry issues, organized into the following categories, should be addressed:

- unresolved safety issues (USIs)
- generic safety issues (GSIs)
- Three Mile Island (TMI) issues
- NRC generic letters (GLs) and information notices (INs)
- studies by the former NRC Office of Analysis and Evaluation of Operational Data (AEOD)

- low-power and shutdown issues
- operating plant event reports

In addition, TMI Action Plan Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff," of NUREG-0737, "Clarification of TMI Action Plan Requirements," dated November 1980, (Supplement 1, January 1983) was included as an HFE issue.

Evaluation:

The applicant performed a thorough review of various industry issues having pertinent operating experience to the AP1000. The applicant performed extensive literature reviews and maintains an up-to-date knowledge of advanced systems and HSI research and experience, as illustrated by the reference lists contained in WCAP-14645, Revision 2, and WCAP-15800, Revision 3. In addition, DCD Tier 2, Section 1.9, provides a detailed summary of the results of the applicant's OER relative to the industry operating experience issues. DCD Tier 2, Section 1.9 and WCAP-15800, Revision 3, addresses USIs/GSIs, TMI issues, NRC GLs, and INs. Chapter 20 of this report provides additional information related to the staff's evaluation of generic HFE issues.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Related HFE Technology

Criterion:

The OER should address related HFE technology. For example, if touch screen interfaces are planned, the applicant should review HFE issues associated with their use.

Evaluation:

The staff determined through review of specific attributes that WCAP-14645 is applicable to AP1000. Section 4.0, "Related Human System Interface (HSI) Technologies Where Little or No Nuclear Plant Experience Exists," and Table 2 of Revision 2 of WCAP-14645 address this criterion. This topical report identifies three such HSI technologies used in the AP1000 design, including soft controls, computerized procedures, and large screen (wall panel) displays. The applicant reviewed the operating experience of soft controls and large overview type displays to identify human factors issues. WCAP-14645, Revision 2, Table 2 identifies 38 issues from these 2 areas, including a discussion in Section 4.0 about the AP1000 computerized procedure system. This discussion states that the computerized procedure system is dynamic and interactive with the remaining HSI. The applicant committed to identify and review any human factors-related issues found in published, comparable systems with relevant operating experience from other industries. Also, in Section 4.0 of WCAP-14645, Revision 2, the applicant summarized the seven items that are the responsibility of the COL applicant. With regard to using proposed HFE technology, WCAP-14645, Revision 2, is applicable to AP1000.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Issues Identified by Plant Personnel

Criterion:

The applicant should conduct personnel interviews to determine operating experience related to predecessor plants or systems. The following topics should be included in the operator interviews:

- plant operations
  - normal plant evolutions (e.g., startup, full power, and shutdown)
  - instrument failures (e.g., safety-related system logic and control unit, fault tolerant controller for nuclear steam supply system (NSSS), local "field unit" for multiplexer (MUX) system, MUX controller for balance of plant, and break in MUX line)
- HSI equipment and processing failure (e.g., loss of video display units, loss of data processing, and loss of large overview display)
  - transients (e.g., turbine trip, loss of offsite power, station blackout, loss of all feed water, loss of service water, loss of power to selected buses and control room power supplies, and safety/relief valve transients)
  - accidents (e.g., main steamline break, positive reactivity addition, control rod insertion at power, control rod ejection, anticipated transient without scram, and loss-of-coolant accidents of various sizes)
  - reactor shutdown and cooldown using the remote shutdown system
- HFE/HSI design topics
  - alarm/annunciation
  - display
  - control and automation
  - information processing and job aids
  - real-time communications with plant personnel and other organizations
  - procedures, training, staffing, and job design

Evaluation:

WCAP-14645, Revision 2, Section 5.0 and Table 3 address operator interviews. The applicant stated that interviews have been conducted during plant operations and after events. Eight specific reports are cited that document the operator interviews. These reports are two NUREG/CRs, two Westinghouse proprietary reports, one Westinghouse nonproprietary topical report, one Electric Power Research Institute (EPRI) report, one utility letter, and one Canadian report. The staff reviewed these reports to determine the scope of the operator interviews. All of the topics above were addressed to some extent in the eight reports, with the exception of remote shutdown and staffing. The interviews identified a number of issues, as documented in Table 3 of WCAP-14645, Revision 2. The issues cover many areas, including emergency situations, cognitively demanding situations, procedures, soft controls, alarms and alarm systems, the safety parameter display system (SPDS), plant startup, and feedwater control.

The applicant submitted a letter on December 16, 1996, with Enclosure 1, "AP600 Open Item Tracking System: Design Issues Tracking," Item No. 4179, which acceptably addressed the staff's previous concerns related to the scope of operator interviews. Specifically, WCAP-14645, Revision 2, provides an explanation of how the operator interview issues were selected and Item No. 4179 of the letter dated December 6, 1996, provides a commitment to address operator interviews on the topics of remote shutdown and staffing. Since the AP1000 is similar to the AP600 in terms of obtaining information through personnel interviews regarding operating experience related to predecessor designs, WCAP-14645, Revision 2, is directly applicable to AP1000.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: Risk-Important Human Actions

Criterion:

The OER should delineate risk-important human actions that have been identified as different or where errors have occurred. The human actions should be identified as requiring special attention during the design process to lessen their probability.

Evaluation:

Open Item 18.3.3.1-1 in the draft safety evaluation report (DSER) identified that the applicant did not address this item in its discussion on developing the OER.

In its July 1, 2003, response to the open item, the applicant indicated that risk-important tasks are used as input to the HFE design activities to identify those activities requiring special attention during the design process, as specified by NUREG-0711. The applicant further indicated that because the AP1000 design differs from existing nuclear power plants, with its passive systems, compact control room, and integrated I&C contributing to such differences, and extensive PRA modeling has been done in support of the AP1000 development, the use of PRA techniques is an effective process to identify risk-important human actions. Therefore, based on the information provided in the July 1, 2003, response, Open Item 18.3.3.1-1 is resolved.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.3.3.2 Issue Analysis, Tracking, and Review

Criterion 1: Analysis Content

Criterion:

Issues should be analyzed to identify the following:

- human performance issues, problems, and sources of human error
- design elements that support and enhance human performance

Evaluation:

In WCAP-14645, Revision 2, the applicant identified human performance issues and problems, as well as sources of human error. The applicant also identified the various aspects of the design and design process that will address these problems by supporting and enhancing human performance. Additionally, in Section 1 of WCAP-14645, Revision 2, the applicant stated that it will continue to review current plant operating experience. As new HFE issues are identified, the applicant will address and track those issues to their resolution.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Documentation

Criterion:

The analysis of operating experience should be documented in an evaluation report.

Evaluation:

The applicant consolidated its OER work into a single document, WCAP-14645, Revision 2. This report addresses all of the areas and issues identified in NUREG-0711, as well as the additional related industry issues discussed in Brookhaven National Laboratory (BNL) Technical Report E2090-T4-3-1/95, "HFE Insights for Advanced Reactors Based Upon Operating Experience." The staff concludes that WCAP-14645, Revision 2, is applicable to the AP1000 with regard to documenting issues related to human performance.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Incorporation into the Tracking System

Criterion:

The applicant should document each operating experience issue determined to be appropriate for incorporation into the design (but not already addressed in the design) in the HFE issue tracking system.

Evaluation:

The applicant submitted a letter on December 16, 1996, as well as WCAP-14645, Revision 2, on January 6, 1997, to address the open issues that remained from the staff's review of WCAP-14645, Revision 1 in the context of the AP600 design certification review. In its December 16, 1996, letter, the applicant acceptably addressed the staff's request for entries of HFE issues that have been included in the HFE issues tracking system, as evidenced by Enclosures 1 through 3. Enclosure 1 provided a copy of the design issues tracking system database report for HFE issues identified as a result of the OER. Enclosure 2 provided a copy of the tracking system database report for HFE issues which resulted from design reviews. Enclosure 3 provided the database report for HFE issues identified by the HSI designers as important HSI design issues.

The staff concludes that WCAP-14645, Revision 2, and the December 16, 1996, letter are applicable to the AP1000 with regard to documenting issues related to human performance in the tracking system.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.3.4 Conclusions

The AP1000 OER review ensured that the applicant identified and analyzed HFE-related problems and issues encountered in previous designs that are similar to the current design under review. This will help to ensure that these problems and issues are not repeated in the development of the current design or, in the case of positive features, that they are included in the design. The staff reviewed the applicant's OER at a complete element review level. Finished products submitted by the applicant to complete the element were available for review. Overall, the applicant has discussed a comprehensive approach to OER. The applicant has also completed fairly extensive reviews, both in the general nuclear power experience area and in the particular area of HSI technology. Therefore, the applicant has acceptably completed this NUREG-0711 element.

18.4 Element 3: Functional Requirements Analysis and Function Allocation

18.4.1 Objectives

The functional requirements analysis and function allocation review for the AP1000 ensures that the applicant has defined the plant's safety functional requirements, and that the function allocations take advantage of human strengths and avoid allocating functions that would be negatively influenced by human limitations.

The functional requirements and function allocations of a new design are typically based on one or more predecessor designs. Many of the functional requirements and function allocations for the new plant may be the same as those of its predecessor. This reflects the evolutionary nature of technology development in complex, high-reliability systems like nuclear power plants. In such cases, operating experience becomes an essential component of the technical basis and rationale for the functional requirements and function allocations. NUREG-0711 describes functions and their allocations as "modified" in comparison to the predecessor design. It is acceptable for functions and allocations that are not modified to be justified based upon the successful operating experience of predecessor designs. The review criteria below reference the concepts of unmodified and modified functions and function allocations.

18.4.2 Methodology

18.4.2.1 Material Reviewed

The staff used the following Westinghouse documents in this review:

- DCD Tier 2
- WCAP-14644

18.4.2.2 Technical Basis

The staff focused its review on an evaluation of the applicant's documents with respect to the topics and general criteria of Element 4, "Functional Requirements Analysis and Function Allocation," of NUREG-0711. The staff reviewed this element at a complete element review level.

18.4.3 Results

This section discusses the results of the staff's evaluation of the AP1000 functional requirements analysis and function allocation in terms of the process, the updating of requirements, predecessor plants and systems, high-level function descriptions, the technical basis for modifying high-level functions, the technical basis for all function allocations, the use of the OER to identify modifications to function allocations, primary allocations and emergency functions, integrated personnel roles across functions, and verification of the functional requirements analysis and function allocation. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections.

Criterion 1: Process

Criterion:

The applicant should perform the functional requirements analysis and function allocation using a structured, documented process reflecting HFE principles.

Evaluation:

The applicant's approach to the AP1000 functional requirements analysis is based on a decision sets model that involves decomposition of plant functions from global, abstract functions, such as "prevent radiation release," to lower level decision sets, such as "control reactor coolant system (RCS) boron concentration." For each decision set, questions are addressed that provide information for accomplishing the goal of the decision set, such as what information is needed, what decisions need to be made, and where the results must go. The results are presented in both graphic and tabular form with the aid of a computer-aided software engineering tool. At the lower levels, cognitive task analysis is performed to provide the requirements for the HSI design. The applicant used a structured approach based on the methodology developed by the International Atomic Energy Agency (IAEA), as described in IAEA-TECDOC-668. This document is based on the methodology developed in NUREG/CR-3331. NUREG-0711 describes both these documents as appropriate sources of function allocation methodology.

Applying the methodology, the applicant first identified those function assignments that are mandatory (required by regulation) and assessed human performance requirements based on task characteristics. For many functions, the applicant identified a combination of human and automated systems. The applicant used a seven-level categorization scheme developed by Billings (1991), and documented the initial set of allocations. The allocations will be reevaluated as the design becomes more detailed.

For tasks assigned to personnel, the applicant considered approaches to support the crew's task performance by reducing the workload. When a task is automated, the applicant defines human task requirements in order for plant personnel to properly monitor the automated activities. In addition, the applicant provided high-level principles for making the automation "human-centered." An especially positive aspect of the described approach is the applicant's consideration of the requirements associated with the task of monitoring automation.

In summary, the staff concludes that the applicant's general approach to functional requirements analysis and allocation is acceptable.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Updating Requirements

Criterion:

The functional analysis should be kept current over the life-cycle of design development and held until decommissioning so that it can be used for design basis when modifications are considered.

Evaluation:

WCAP-14644, Section 2.3, discusses the verification and updating of functional requirements analysis. Several different analyses contribute to the evaluation of functional requirements including the DCD Tier 2 safety analyses (Chapter 15), the PRA analyses, and the function-based task analyses (FBTAs). The DCD Tier 2 safety analyses address the ability of the plant functions, systems, and processes to cope with design-basis events. The PRA analyses address the ability of plant functions, systems, and processes to cope with beyond-design-basis accidents. The FBTAs performed by the HSI design team provide verification of the detailed sensor, as well as control specifications for critical safety function (CSF)-related requirements.

WCAP-14644, Section 2.3, also describes the mechanisms for modifying functional requirements, if the analyses described above identify a need to do so. Modifications would be accomplished through the formal procedures described in the design configuration change control process (discussed in the Element 1 review). The procedures assure that the change is properly implemented, documented, and verified. This information provides an acceptable explanation of the process by which functional requirements will be verified and changed, if required. The staff concludes that WCAP-14644 is applicable to the AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Predecessor Plant and Systems

Criterion:

The applicant should provide a description of the plant functions, processes, and systems, as well as a comparison of these to the reference plants/systems, to identify any areas of difference that exist. The description should also address how the results of the functional requirements analysis are verified and updated as the design process proceeds.

Evaluation:

WCAP-14644, Section 2, addresses this criterion. Table 1 of WCAP-14644 identifies the CSFs, including subcriticality, core cooling, heat sink, RCS integrity, containment, and RCS inventory. Table 2 provides a comparison of the CSFs and their success paths to those of the reference plant. The reference plant is the generic PWR design for currently licensed

Westinghouse nuclear power plants. WCAP-14644, Section 2.1.3 and Table 3 provide a comparison of the design of the structures, systems, and components (SSCs), as well as their function allocation between the new design and the reference plants. The table indicates whether the success path for each CSF is unchanged, modified, or new. The CSFs for the new design are the same as those for the reference plants, but the success paths and SSCs are different. The major differences are (1) the use of safety-related, passive systems for safety injection and decay heat removal, (2) the use of advanced digital I&C, (3) automation of certain SSC actuation and control functions that help reduce operator workload, and (4) design changes that were identified through a review of operating experience. WCAP-14644 provides a detailed and acceptable description of the functions, processes, and systems as well as a comparison to the reference plants/systems, so that one can identify areas of difference that exist. This information provides an acceptable explanation of the process for comparing plant functions and systems with reference plants/systems. The staff concludes that WCAP-14644 is applicable to AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: High-Level Function Descriptions

Criterion:

The applicant should provide a description of the functions and systems, along with a comparison to the reference plants/systems (i.e., the previous plants or plant systems upon which the new system is based). Function decomposition should be done at several levels, starting at "top level" functions, at which a very general picture of major functions is described, and continuing through the plant process level to lower levels until a specific, critical end-item requirement emerges (e.g., a piece of equipment, software, or an operator). The functional decomposition should address the following levels:

- high-level functions (e.g., maintain RCS integrity) and critical safety functions (e.g., maintain RCS pressure control)
- specific plant systems and components

Evaluation:

The applicant has defined high-level safety functions and included the functions required to prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public. The safety processes themselves will be defined at the next level when the FBTAs are completed. A method for doing this has been established and implemented, as illustrated by the sample case in WCAP-13957. The staff concludes that both WCAP-14644 and WCAP-13957 are applicable to the AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: Technical Basis for Modifying High-Level Functions

Criterion:

The applicant should document the technical basis for modifying high-level functions in the new design, as compared to the predecessor design.

Evaluation:

WCAP-14644, Section 2.3 describes the mechanisms for modifying functional requirements, if the analyses described above identify a need to do so. Modifications would be accomplished through the formal procedures described in the design configuration change control process. The procedures assure that the change is properly implemented, documented, and verified. The staff concludes that both WCAP-14644 and WCAP-13957 are applicable to the AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 6: Technical Basis for All Function Allocations

Criterion:

The applicant should document a technical basis for all function allocations, including the allocation criteria, rationale, and analyses methods.

Evaluation:

WCAP-14644, Sections 1.4, 1.5, and 3.0, provide the technical basis for function allocations, including the criteria, rationale and analyses methods. In Section 4.3, the applicant also described the mechanisms for modifying function allocations. If problems with respect to allocation are identified, a process is in place to address the problem. Options include modifications to the HSI to better support the operators task, modifications to system design to change the level of automation, or modifications to the staffing assumptions.

Once the problem has been addressed, modifications will be accomplished through the formal procedures described in the design configuration change control process (discussed in the Element 1 review). These procedures assure that the change is properly implemented, documented, and verified. The staff concludes that WCAP-14644 is applicable to the AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 7: The Role of the OER in Modifying Function Allocations

Criterion:

The OER should be used to address the case of modified processes. The applicant should consider problematic OER issues during the function allocation analyses for modified functions.

Evaluation:

The role of operating experience in the identification of acceptable allocations, or for allocations that need to be addressed, is an essential part of initial allocations (as identified in the basis for the applicant's approach, IAEA-TECDOC-668). In WCAP-14644, Section 4.2, the applicant describes the evaluation of the integrated role of the operator using task and workload analysis, HSI design and evaluation, and verification and validation (V&V). In WCAP-14644, the applicant indicates that because of the dynamic and interactive aspects of human performance, the allocations will be evaluated through subsequent HFE analyses throughout the design process. Following the initial allocations by system designers, the integrated role of operators is assessed during task analyses when workload evaluations are conducted. Because the task analyses will address a full range of operating modes, they provide an opportunity to identify operational phases in which workload can be expected to be high. The HSI will be specifically designed to support the operator's functional role in the plant (through the support of the functional decomposition analyses) which will be evaluated in verification activities. The final allocation will be evaluated as part of an integrated system.

In WCAP-14644, Section 4.3, the applicant describes the mechanisms for modifying function allocations. If allocation problems are identified, a process is in place to address the problem. Options include modifications to the HSI to better support the operators tasks, modifications to the system design to change the level of automation, or modifications to the staffing assumptions. Once the problem has been addressed, modifications will be accomplished through the formal procedures described in the design configuration change control process (discussed previously in the review of Element 1). These procedures assure that the change is properly implemented, documented, and verified.

The applicant described an acceptable approach to evaluating the functional role of the operator and to developing design changes to modify the function allocations, should it become necessary as the design develops. The staff concludes that WCAP-14644 is applicable to the AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 8: Allocation Analysis and Primary Allocations and Emergency Functions

Criterion:

The allocation analysis should consider not only the primary allocations to personnel, but also their responsibilities to monitor automatic functions and to assume manual controls when automatic systems fail.

Evaluation:

In addition to the information presented in the previous evaluation of Criterion 7, WCAP-14644, Section 4.2, specifically indicates that the allocation analysis will consider the need for manual backup, manual intervention or manual override as part of the Westinghouse FBTA process, which is integrated with function allocation. The staff concludes that WCAP-14644 is applicable to the AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 9: Integrated Personnel Role Across Functions

Criterion:

The applicant should provide a description of the integrated personnel role across functions and systems in terms of personnel responsibility and level of automation.

Evaluation:

In WCAP-14644, Section 4.2, the applicant describes the evaluation of the integrated role of the operator using task and workload analysis, HSI design and evaluation, and V&V. The evaluation of Criterion 7 presented above provides additional detail. The staff concludes that WCAP-14644 is applicable to the AP1000 with regard to performing this aspect of the functional requirements analysis and function allocation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 10: Verification of the Functional Requirements Analysis and Function Allocation

Criterion:

The applicant should verify the functional requirements analysis and function allocation for high-level, safety-related functions.

Evaluation:

See the evaluation for Criterion 2, above, for the discussion of updating and verifying the functional requirements analysis.

Based on that information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.4.4 Conclusions

This review ensured that the applicant has defined the plant's safety functional requirements, and that the functional allocations take advantage of human strengths and avoid allocating functions that would be negatively influenced by human limitations. The functional requirements analysis and the function allocation analysis were reviewed at a complete element review level. The applicant discussed a detailed analysis of functional requirements and allocation, and has identified a process to further evaluate allocation, if necessary. Therefore, the staff finds that the applicant has acceptably satisfied this NUREG-0711 element.

18.5 Element 4: Task Analysis

18.5.1 Objectives

The objective of this review is to ensure that the applicant's task analysis identifies the specific tasks that are needed to accomplish a specific function, as well as their information, control, and task-support requirements.

18.5.2 Methodology

18.5.2.1 Material Reviewed

The staff used the following Westinghouse documents in this review:

- DCD Tier 2
- WCAP-14651, Revision 2, "Integration of Human Reliability Analysis with Human Factors Design Implementation Plan," issued May 8, 1997
- WCAP-14690, Revision 1, "Designer's Input to Procedure Development for the AP600," issued June 1997
- WCAP-14655, Revision 1, "Designer's Input for the Training of Human Factors Engineering Verification and Validation Personnel," issued August 8, 1996
- WCAP-14695, "Description of the Westinghouse Operator Decision-Making Model and Function Based Task Analysis Methodology," issued July 23, 1996

18.5.2.2 Technical Basis

The staff focused its review on an evaluation of the applicant's documents with respect to the topics and general criteria of Element 5, "Task Analysis," of NUREG-0711. The staff reviewed the applicant's task analysis at an implementation plan review level because the work will not be completed in this area until after design certification.

18.5.3 Results

This section discusses the results of the staff's evaluation of the AP1000 task analysis process, including the scope of the task analysis, task linking, task analysis iterations, job design issues, minimum inventory, and input to HSI design, procedures, and training. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections.

Criterion 1: Scope of the Task Analysis

Criterion:

The scope of the task analysis should include selected representative and important tasks from the areas of operations, maintenance, test, inspection, and surveillance. The analyses should be directed to the full range of plant operating modes, including startup, normal operations, abnormal and emergency operations, transient conditions, and low-power and shutdown conditions.

Evaluation:

The applicant's approach to task analysis is to evaluate tasks from the perspective of (1) FBTA, and (2) operational sequence analysis (OSA). DCD Tier 2, Section 18.5.2.1, "Function-Based Task Analyses," and WCAP-14695 describe FBTA. The scope of the FBTA focuses on decomposition of the higher level functions (as described in Level 4 in DCD Tier 2, Figure 18.5-1). This approach is an appropriate and acceptable means of identifying those function-based requirements that are not dependent on specific operator tasks. The scope of the OSA includes the full range of plant operating modes (i.e., startup, normal operations, abnormal and emergency operations, transient conditions, and low-power and shutdown conditions). The scope includes tasks representing the full range of activities in the AP1000 ERGs, as well as tasks identified as critical or risk-significant. DCD Tier 2, Section 18.5.1, "Task Analysis Scope," further indicates that the traditional task analyses will include tasks that involve maintenance, test, inspection, and surveillance. The tasks selected will involve activities involving risk-significant SSCs. The staff concludes that WCAP-14695 and the description provided in DCD Tier 2 related to task analysis scope are applicable to AP1000 with regard to performing this task analysis activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Task Linking

Criterion:

Tasks should be linked using a technique such as operational sequence diagrams. Task analyses should begin on a gross level and involve the development of detailed narrative descriptions of personnel tasks. The analyses should define the nature of the input, process, and output needed by and of personnel.

Evaluation:

As indicated in DCD Section 18.5, "AP1000 Task Analysis Implementation Plan," and in WCAP-14695, the applicant's functional task analysis methodology begins with the high-level functional goals and then decomposes them. A goal-means structure will be used to map the cognitive and physical tasks that define the operational space of the plant to each plant function. The goal-means structure representation is based on the concept of describing the plant's functional processes in terms of the goals to be achieved and the means or mechanisms available for achieving them.

Cognitive task analysis methodology is used to identify the monitoring and feedback, planning, and control requirements. Because the emphasis of the task analysis is on cognitive requirements, the methodology described will acceptably provide the necessary information to support the definition of requirements for information gathering, decision-making, response, and feedback.

The applicant provided a discussion and clarification of the integration of both the FBTA and OSA approaches to the task analysis in the AP1000 design process. While the focus of FBTA is on decomposition of the higher level AP1000 functions, the focus of the OSA will be on the analysis of the operational tasks, as defined within the scope of task analysis activities.

The OSA will be performed in two phases. The first phase (OSA-1) tasks will be developed to include plant state data, data source, actions, criteria/reference values, feedback, time, sequencing requirements, support requirements, and work environment considerations. These results will provide the operational requirements for task performance. These requirements and constraints provide input to the HSI design development.

The resulting designs are tested in concept tests, which enable further refinement of the analysis results. To accomplish this, a second OSA phase (OSA-2) is performed on a representative subset of the tasks analyzed in the first phase of OSA, including those which are risk-important and those for which there are performance concerns. These analyses address the completeness of available information, time to perform tasks, operator workload, and staffing. In summary, the combination of FBTA and OSA provides a particularly strong technical basis for identifying operational requirements to be addressed in the detailed HSI design. The staff concludes that WCAP-14695 and the description provided in DCD Tier 2 related to linking tasks, developing descriptions, and defining inputs, processes, and output of the tasks analyses, are applicable to the AP1000 with regard to performing this task analysis activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Task Analysis Iterations

Criterion:

The task analysis should be iterative and become progressively more detailed over the design cycle.

Evaluation:

The DCD Tier 2 and WCAP-14695 describe a task analysis process that is iterative, the contents of which are developed and refined as it is performed over the design cycle. The applicant's task analysis process is based on functional decomposition and combines traditional task analysis with cognitive task analysis methods. The use of these two analytic techniques attempts to (1) ensure that a complete set of operator tasks is selected for evaluation, (2) determine the process plant data needed to support operator decisions, and (3) make the plant equipment achieve its designed purposes. The staff concludes that WCAP-14695 and the description provided in DCD Tier 2 related to task analysis iteration are applicable to the AP1000 with regard to performing this task analysis activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Job Design Issues

Criterion:

The task analysis should incorporate job design issues such as the following:

- the number of crew members
- crew member skills
- allocation of monitoring and control tasks to the formation of a meaningful job and management of a crew member's physical and cognitive workload

Evaluation:

The applicant indicated in DCD Tier 2 that the second set of OSA evaluations will incorporate crew staffing considerations. The workload assessment done as part of these analyses will provide "an indication of the adequacy of staffing assumptions" (DCD Tier 2, page 18.5-4). When high workload or time limits occur, alternative staffing assumptions, task allocations, or design changes will be evaluated. With respect to skills, the applicant assumed the skill requirements addressed by the NRC training requirements (i.e., no special skills are assumed for AP1000 operators). The staff finds this to be an acceptable approach.

In DCD Tier 2, the applicant also stated that a COL applicant referencing the AP1000 certified design will document the scope and responsibilities of each MCR position, considering the assumptions and results of the task analysis. This is COL Action Item 18.5.3-1. The staff concludes that WCAP-14695, the description provided in DCD Tier 2 related to job design issues, and the COL action item, are applicable to the AP1000 with regard to performing this task analysis activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: Minimum Inventory

Criterion:

The applicant should use the task analysis results to define a minimum inventory of alarms, displays, and controls necessary to perform crew tasks based upon both task and I&C requirements.

Evaluation:

DCD Tier 2, Section 18.5.2.1, "Function-based Task Analysis," indicates that the FBTA is used as a completeness check on the availability of needed indications, parameters, and controls. The DCD Tier 2 also indicates that the OSAs will provide information on the inventory of alarms, controls, and parameters needed to perform sequences selected for analysis, which include those addressed in the earlier discussion of Criterion 1, "Scope of the Task Analysis." The applicant described a minimum inventory of alarms, displays, and controls for the AP1000 (the staff performed a complete review of the inventory for the AP1000 design certification; Section 18.12 of this report provides the evaluation details). The staff concludes that the description provided in DCD Tier 2 related to task analysis and minimum inventory and the additional detail in WCAP-14645, are applicable to the AP1000 with regard to performing this task analysis activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 6: Input to HSI Design, Procedures, and Training

Criterion:

The task analysis results should provide input to the HSI design, procedures, and personnel training programs.

Evaluation:

DCD Tier 2, Sections 18.9, "Procedure Development," and 18.5.2, "Task Analysis Implementation Plan," do not identify the relationship between task analysis and procedures or training development. Further, DCD Tier 2, Figure 18.2-3, "Overview of the AP1000 Human

Factors Engineering Process," does not show task analysis as an input to either procedure or training development. However, WCAP-14690, Revision 1, does address the relationship between procedure development and task analysis. This topical report states that the "plant operating procedures' technical bases...shall be consistent with...task analyses" (WCAP-14655, Revision 1, page 2-1). In addition, the EOP technical content should be developed from the ERGs with additional input from the task analysis, among other things. Further, both these items are COL items. The staff considers these statements to be appropriate and acceptable.

The relationship between training program development and task analysis is addressed in WCAP-14655, Revision 1, "Designer's Input for the Training of HFE V&V Personnel." This topical report indicates that the results of the task analysis will serve as input to the training of V&V personnel. Following V&V, a "training insights report" will be developed and provided to the COL applicant. The report will include, among other things, the task analysis that is completed for the HFE V&V, as well as the knowledge, skills, and abilities analysis associated with those tasks (WCAP-14655, Revision 1, page 4-1). Thus, while procedures and training program development are COL activities, the applicant will provide the COL with the input from task analyses. The staff understands this to mean that the COL applicant will use the information from the AP1000-specific task analysis in the development of its procedures and training programs. This is COL Action Item 18.5.3-2.

The staff expects that the COL applicant will use task analysis information for all training and procedure efforts that involve tasks for which task analyses were performed, even if they go beyond the scope of the V&V activities. The staff concludes that WCAP-14695 and the description provided in DCD Tier 2 related to task analysis input to HSI design, procedures, and training are applicable to the AP1000 with regard to performing this task analysis activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.5.4 Conclusions

The task analysis review ensured that the applicant's task analysis identifies the requirements of the tasks that plant personnel are required to perform. The staff reviewed the applicant's task analysis at an implementation plan level of detail; finished products to complete the element were not available for review, but the methodology for conducting a complete task analysis was evaluated. The COL applicant will use this methodology to conduct a complete HFE task analysis after design certification. This is COL Action Item 18.5.3-3. The applicant has acceptably developed a task analysis implementation plan to satisfy this element of NUREG-0711.

18.6 Element 5: Staffing and Qualifications

18.6.1 Objectives

The objective of this review is to ensure that the applicant has analyzed the requirements for the number and qualifications of personnel in a systematic manner, which includes demonstrating a thorough understanding of task requirements and applicable regulatory requirements.

18.6.2 Methodology

18.6.2.1 Material Reviewed

The following Westinghouse documents were used in this review:

- DCD Tier 2
- WCAP-14075, "AP600 Design Differences Document for the Development of Emergency Operating Guidelines Report," issued May 20, 1994
- WCAP-14694, "Designer's Input to Determination of the AP600 Main Control Room Staffing Level," issued July 31, 1996

18.6.2.2 Technical Basis

The staff focused its review on evaluating the Westinghouse documents with respect to the general criteria and topics of NUREG-0711, Element 6, "Staffing and Qualifications." In addition, the staff also used the requirements of 10 CFR 50.54, "Conditions of Licenses."

18.6.3 Results

This section discusses the results of the staff's evaluation of the AP1000 staffing and qualifications process in terms of applicable requirements, number and qualifications of personnel, staffing analysis iteration and the basis for staffing. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them and 10 CFR 50.54. The results of the staff's evaluation are presented in the following sections:

Criterion 1: Applicable Requirements

Criterion:

Staffing and qualifications should address applicable requirements of 10 CFR 50.54 and associated guidance in NUREG-0800, Section 13.1.

Evaluation:

The applicant, in DCD Tier 2, Section 18.6.1, "Combined License Information Item," stated that the staffing requirements of 10 CFR 50.54(m) will be addressed by COL applicants referencing the AP1000 design.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Number and Qualifications of Personnel

Criterion:

The staffing analysis should determine the number and background (qualifications) of personnel required during the full range of plant conditions and tasks, including operational tasks (normal, abnormal, and emergency), plant maintenance, and plant surveillance/testing. Element 1 of NUREG-0711 identifies the plant personnel that should be considered.

Evaluation:

DCD Tier 2, Section 18.6.1, "Combined License Information Item," states that the COL applicant will address staffing levels and qualifications of plant personnel, including operations, maintenance, engineering, I&C, radiological protection, security, and chemistry.

While this description is acceptable, the staff determined that it is necessary for the COL applicant to (1) address the staffing considerations in NUREG-0711, and (2) identify the minimum documentation that is necessary for the staff to complete its review. This is COL Action Item 18.6.3-1.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Staffing Analysis Iteration

Criterion:

The staffing analysis should be iterative, that is, the initial staffing goals should be reviewed and modified as the analyses associated with other NUREG-0711 elements are completed.

Evaluation:

The discussion under Criterion 2, "Number and Qualifications of Personnel," above considered this criterion. This criterion is included in COL Action Item 18.6.3-1.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Basis for Staffing

Criterion:

The staffing analysis should consider the issues associated with the following NUREG-0711 elements and then compare these issues to staffing assumptions regarding the number and qualifications of operations personnel. The basis for staffing should be modified to address these elements:

- operating experience review
  - operational problems and strengths that resulted from staffing levels in predecessor systems
- function analysis and allocation
  - mismatches between functions allocated to the operator and the qualifications of anticipated operators
- task analysis
  - the knowledge, skills, and abilities required for operator tasks addressed by the task analysis
  - requirements for operator response time and workload
  - requirements for operator communication and coordination
  - the job requirements that result from the sum of all tasks allocated to each individual operator both inside and outside the control room
- human reliability assessment
  - the effect of overall staffing levels on plant safety and reliability
  - the effect of overall staffing levels and the coordination of individual operator roles on critical human actions
  - the effect of overall staffing levels and the coordination of individual operator roles on human errors associated with the use of advanced technology
- HSI design
  - staffing demands resulting from the locations and use (especially concurrent use) of controls and displays
  - the requirements for coordinated actions between individual operators
- procedures
  - staffing demands resulting from requirements for concurrent use of multiple procedures

  - skills, knowledge, abilities, and authority required of operators by the procedures

- training

  - concerns about crew coordination identified during the development of training

- verification and validation

  - ability of a minimum size operating crew to control plant during validation scenarios

  - ability of operators to effectively communicate and coordinate actions during all validation scenarios

  - ability of operators to maintain awareness of plant conditions and operator actions throughout all validation scenarios

Evaluation:

The discussion under Criterion 2, "Number and Qualifications of Personnel," above considered this criterion. This criterion is included in COL Action Item 18.6.3-1.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.6.4 Conclusions

This review ensures that the applicant has analyzed the requirements for the number and qualifications of personnel in a systematic manner that demonstrates a thorough understanding of task requirements and applicable regulatory requirements.

The applicant identified staffing and qualifications as a COL action item with applicable issues to be addressed by the COL. This is COL Action Item 18.6.3-1. In addition, WCAP-14694 provides additional information related to this element and available for the COL. The staff concludes that WCAP-14694 and the description provided in DCD Tier 2 related to staffing and qualifications are applicable to the AP1000 with regard to performing this staffing and qualifications activity.

18.7 Element 6: Human Reliability Analysis

18.7.1 Objectives

The objectives of the human reliability analysis (HRA) reviews are to ensure that—

- the applicant has addressed human error mechanisms in the design of the plant HFE (i.e., the HSIs, procedures, shift staffing, and training) to minimize the likelihood of personnel error and to provide for error detection and recovery capability

- the HRA activity effectively integrates the HFE program activities, as well as the PRA and risk analysis activities

18.7.2 Methodology

18.7.2.1 Material Reviewed

The staff used the following Westinghouse documents in this review:

- DCD Tier 2

- WCAP-14651, Revision 2, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," issued May 8, 1997

- Chapter 30 of the AP1000 Probabilistic Risk Assessment (PRA)

18.7.2.2 Technical Basis

The staff focused its review on an evaluation of the applicant's documents with respect to the topics and general criteria of Element 7, "Human Reliability Analysis," of NUREG-0711. Section 7.1 of NUREG-0711 addresses the technical review of HRA methodology. These criteria were not applied by the staff as part of the HFE review because this part of the HRA review is being conducted in conjunction with the staff's PRA review which is addressed in Chapter 19 of this report. Instead, the HFE review focused on the integration of the HRA with the HFE design.

The applicant indicated that the HRA implementation plan, the PRA, and the HRA are within the scope of design certification. However, the analysis results report for this HRA element of NUREG-0711 requires a completed FBTA report and is not within the scope of design certification. Therefore, the staff reviewed the applicant's HRA at an implementation plan review level, because the applicant will not complete work in this area until after design certification.

18.7.3 Results

This section discusses the results of the staff's evaluation of the AP1000 HRA in terms of the implementation plan, risk-important human actions, HRA/PRA insights, and HRA validation. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections.

Human Factors Engineering

General Criterion: Implementation Plan

Criterion:

While the NUREG-0711 criterion for this element does not explicitly include an implementation plan, such a plan is needed to address the NUREG-0711 criterion-based review to follow. The need for an implementation plan is, however, identified as an applicant submittal to be provided to the NRC for staff review and is identified, for purpose of the staff's evaluation, as a "General Criterion." This criterion addresses the availability of an implementation plan in DCD Tier 2.

Evaluation:

In WCAP-14651, Revision 2, the applicant discusses in detail the various items associated with proper integration of the PRA/HRA and the HFE processes, including use of HRA/PRA insights to guide HFE design, identification of critical human actions and risk-important tasks, task analyses for critical human actions and risk-important tasks, reexamination of critical human actions and risk-important tasks, and validation of the HRA performance assumptions. Thus, the applicant developed an implementation plan with appropriate scope. Further, DCD Tier 2, Section 18.7 references this implementation plan. The following evaluations of individual criteria discuss the acceptability of specific items.

In Sections 3.2 and 5.0 of WCAP-14651, Revision 2, the applicant addressed the issue of whether there is a need to reevaluate and possibly requantify the HRA/PRA after the HFE design is complete. The applicant stated that all performance assumptions will be confirmed as part of both the task analyses and the control room validation. The COL applicant will then evaluate whether any of the assumptions used in the HRA must be changed. If necessary, the COL applicant will modify the HRA and assess the impact of such modifications on the PRA. The COL applicant will submit reports documenting the results to the NRC for review. This is COL Action Item 18.7.3-1.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 1: Risk-Important Human Actions

Criterion:

The applicant should identify risk-important human actions from the HRA and PRA and use these actions as input to the HFE design effort. The applicant should develop these critical actions from the Level 1 (core damage) and Level 2 (release from containment) portions of the PRA, including both internal and external events. The applicant should also develop the actions using selected (more than one) importance measures and the HRA sensitivity analyses to ensure that an important action is not overlooked because of the selection of the measure or the use of a particular assumption in the analysis.

Evaluation:

The applicant submitted WCAP-14651, Revision 2, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," on May 8, 1997.

The risk-important tasks (critical human actions) are defined as "tasks that must be accomplished in order for personnel to perform their functions. In the context of PRA, critical tasks are those that are determined to be significant contributors to plant risk." In its integration plan, the applicant chose to subdivide the NUREG-0711 critical human actions into two categories, critical human actions and risk-important tasks. However, the applicant indicated that its HFE design program will address both of these types of actions.

The threshold for defining a Westinghouse critical human action is high. It is any action that, if failed, would result in a total core damage frequency (CDF) of greater than or equal to 1E-4 events/Rx-year, or a severe release frequency greater than or equal to 1E-5 events/Rx-year. Using these thresholds, the AP1000 has no critical human actions because of the low overall CDF, the passive nature of the design, and the high value of the threshold selected for the AP1000. The staff has accepted the applicant's high thresholds for defining critical human actions because the applicant also defines risk-important tasks in a manner acceptable to the staff. The applicant uses these definitions of risk-important tasks appropriately for other portions of the control room design where critical actions were intended. In addition, as indicated in Section 18.2 of this report, because of the high threshold for defining critical human actions, the staff considered an additional task (manual actuation of the automatic depressurization system (ADS)) as critical. As such, a necessary task should be included in the minimum inventory of control room controls, displays, and alarms. The applicant added this action to the inventory. The staff understands that, although the applicant has not identified any critical human actions based on the preliminary results from the PRA studies completed in 1996, critical human actions may be identified as PRA studies are updated.

The integration plan details the thresholds for defining a risk-important task, including both quantitative and qualitative criteria. For the determination of risk-important tasks, the applicant will use the following PRA studies:

- the internal events at-power PRA
- the shutdown events PRA
- the focused PRA for regulatory treatment of non-safety-related systems (RTNSS) analysis
- the external events PRA (for fire and flood events)
- the seismic margins PRA

For the quantitative criteria, the applicant will use two importance measures, risk achievement (or risk-increase) worth and risk reduction (or risk-decrease) worth. The threshold for risk-increase importance for at-power internal events and shutdown events is 200 percent, or a risk achievement worth of 3.0. This will be applied to both the Level 1 (core damage frequency) and the Level 2 (severe release from containment) PRAs.

WCAP-14651, Revision 2, specifies that all PRAs used in the determination of risk-important tasks define the quantitative thresholds, add five well-specified qualitative criteria, and provide example results of risk-important tasks in Appendix A. The latest baseline values of the various PRA studies, as referenced in the integration plan, were determined to range from 6.5E-7 events/Rx-year down to about 2E-10 events/Rx-year. These are low values compared to the PRAs for current day plants. Thus, the AP1000 can accept a somewhat higher percentage increase than would be acceptable for current plants. Further, using only the quantitative criteria, the integration plan in Appendix A provides examples of risk-important tasks. Depending on how one converts human action basic events to tasks, the applicant identified 13 to 15 risk-important tasks. This appears to be a reasonable number of risk-defined operator tasks for the applicant to address in the task analysis portion of the HSI design.

Thus, the applicant developed an acceptable approach to define critical human actions and risk-important tasks from the PRA/HRA for use as input to the HFE design effort. These risk-important tasks are developed from Level 1 and Level 2 PRAs and include consideration of both internal and external events. They will be selected using multiple measures and criteria to ensure that important actions are not overlooked. The staff concludes that WCAP-14651, Revision 2 and the description provided in DCD Tier 2 related to developing risk-important human actions are applicable to the AP1000 with regard to performing this HRA integration activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Detailed Examination of Risk-important Human Actions

Criterion:

The applicant should examine, by function analysis, task analysis, HSI design, procedure development, and training, those risk-important human actions that are identified in the HRA/PRA as posing serious challenges to plant safety and reliability to identify either changes to the operator task or the control or display environment to reduce or eliminate undesirable sources of error.

Evaluation:

Section 4.0 of WCAP-14651, Revision 2, states that any critical human action or risk-important task (e.g., risk-important human action) that is determined to be a potentially significant contributor to risk will be reexamined by task analysis, HSI design, and procedure development. These evaluations will be used to identify changes to the operator task or the HSI to reduce the likelihood of operator error and provide for error detection and recovery capability.

Section 3.2 of this topical report discusses how the task analyses will be used to address the assumptions made in the HRA by developing more accurate estimates of workload and task completion times. The applicant will provide this information to the Westinghouse HRA/PRA group. The staff concludes that WCAP-14651, Revision 2, is applicable to the AP1000 with regard to performing this HRA integration activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Using HRA/PRA Insights

Criterion:

The applicant should specifically address the use of the HRA/PRA results by the HFE design team (i.e., how the HFE Program addressed risk-important personnel tasks through HSI design, procedural development, and training to minimize the likelihood of operator error and provide for error detection and recovery capability).

Evaluation:

The applicant designed the AP1000 taking into account lessons learned from existing plant experience and the results of past HRAs and PRAs. This allowed the applicant to reduce the potential for human error. The applicant stated that this simplifies the plant and reduces the number of human actions required. For example, no human actions are required to maintain core cooling following design-basis events.

Further, Section 1.2 of WCAP-14651, Revision 2, provides a discussion of how the HRA/PRA results will be used in task analysis, HSI design, procedure development, and V&V to identify changes to operator tasks, procedures, or the HSI to minimize the likelihood of operator error and provide for error detection and recovery capability.

The applicant stated that training program development is a COL responsibility. Section 1.2 of the applicant's implementation plan discusses how it will provide the COL applicant with documentation that includes a description of the HRA assumptions, PRA results relevant to training, and insights relevant to training based upon the V&V. This will include a list of critical human actions (if any), risk-important tasks, and performance requirements for those actions (e.g., response time). This is included in COL Action Item 18.10.3-1.

The staff concludes that WCAP-14651, Revision 2, is applicable to the AP1000 with regard to performing this HRA integration activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: HRA Validation

Criterion:

The applicant should validate HRA assumptions, such as decisionmaking and diagnosis strategies for dominant sequences, by walk-through analyses with personnel with operational experience using a plant-specific control room mockup, prototype, or simulator. The applicant should conduct these reviews before the final quantification stage of the PRA.

Evaluation:

Section 5.0 of WCAP-14651, Revision 2, discusses the validation of the HRA performance assumptions. It states that validation of the HRA operator performance assumptions will be performed as part of the integrated HFE system validation. This will include scenarios that include critical or risk-important human actions, as well as specific performance assumptions that the HRA/PRA group identifies for confirmation. The applicant will not validate the quantitative HRA probabilities. WCAP-14651 identifies the qualifications of personnel involved in the analyses. Although walk-throughs are not specifically identified in the WCAP, exercises using scenarios are mentioned as part of the validation effort, which is conducted in the context of the overall integrated HFE system validation and incorporates control room walk-throughs and extensive simulator exercises. After reviewing the results of the validation, the HRA/PRA group will determine whether any changes need to be made to the HRA assumptions or HRA quantification. If changes are needed, the applicant will modify the HRA and assess the impact of the changes on the PRA. The applicant will document the results of the exercises intended to validate the HRA performance assumptions in a report which it will submit to the NRC for review as part of the COL application information provided in COL Action Item 18.7.3-1.

The staff concludes that WCAP-14651, Revision 2, is applicable to the AP1000 with regard to performing this HRA integration activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.7.4 Conclusions

This review ensured that (1) the HRA activity effectively integrates the HFE program activities and PRA/risk analysis activities, and (2) the applicant has addressed human error mechanisms in the design of the plant HFE (i.e., the HSIs, procedures, shift staffing, and training in order to minimize the likelihood of personnel error and to provide for error detection and recovery capability). The staff reviewed the HRA integration at an implementation plan level of detail.

The applicant developed an acceptable implementation plan for integrating the HRA with HFE for the AP1000 design. The COL applicant referencing the AP1000 certified design will be responsible for the execution and documentation of the HRA/HFE integration implementation plan. This is COL Action Item 18.7.4-1.

18.8 Element 7: Human-System Interface Design

This section discusses the results of the staff's review of the applicant's process for HSI design. A detailed review of the specific features of the HSI (such as the alarms, displays, and controls of the control room and the remote shutdown station) was beyond the scope of this review because the applicant will not have completed the HSI design features for the AP1000 design by the time of design certification. Therefore, the staff's review addressed the HSI design process methodology and was conducted at an implementation plan review level. The staff included the SPDS in its HSI review. Although the MCR is not fully designed, the staff evaluated the applicant's approach to meeting the functional requirements for the SPDS (see Section 18.8.2 of this report).

18.8.1 HSI Design Process

18.8.1.1 Objectives

The objective of this review is to evaluate the process by which HSI design requirements are developed and HSI designs are selected and refined. The review should ensure that the applicant has appropriately translated function and task requirements to the CDAs that are available to the crew. The applicant should have systematically applied HFE principles and criteria, along with all other function, system, and task design requirements, to identify HSI requirements, select and design HSIs, and resolve HFE/HSI design problems and issues. The applicant should document for review the process and rationale for the HSI design, including the results of trade-off studies, other types of analyses and evaluations, and the rationale for selection of design and evaluation tools.

18.8.1.2 Methodology

18.8.1.2.1 Material Reviewed

The staff used the following Westinghouse documents in this review:

- DCD Tier 2
- WCAP-14396, Revision 3, "Man-in-the-Loop Test Plan Description," issued November 27, 2002
- WCAP-14401, Revision 3, "Programmatic Level Description of the AP600 Verification and Validation Plan," issued April 1997
- WCAP-15847, Revision 1, "AP1000 Quality Assurance Procedures Supporting NRC Review of AP1000 DCD Sections 18.2 and 18.3," issued December 2002
- WCAP-14695, "Description of the Westinghouse Operator Decision-Making Model and Function-Based Task Analysis Methodology," issued July 23, 1996

18.8.1.2.2 Technical Basis

The staff focused its review on an evaluation of the applicant's documents with respect to the topics and general criteria of Element 8, "Human-System Interface Design," of NUREG-0711. The staff reviewed the applicant's HSI design at an implementation plan review level because the applicant will not complete work in this area until after design certification.

18.8.1.3 Results

This section discusses the results of the staff's evaluation of the AP1000 HSI design in terms of the sources of input to the HSI design process, the concept of operations, the functional requirements specification, the HSI concept design, the HSI detailed design and integration, HSI tests and evaluations, trade-off evaluations, performance-based tests, and HSI design documentation. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections:

Criterion 1: Sources of Input to the HSI Design Process

Criterion:

The analyses performed in earlier stages of the design process should be used to identify HSI requirements. These sources include (1) analysis of personnel task requirements (i.e., input from OER, functional requirements analysis and function allocation, task analysis, staffing/qualifications and job analyses); (2) systems requirements (i.e., constraints imposed by the overall I&C design); (3) applicable regulatory requirements; and (4) other applicant-identified inputs that are applicable to the HSI design.

Evaluation:

DCD Tier 2, Section 18.8, "Human System Interface Design," addresses the design of the HSI based on task analysis and other design inputs. It provides a general description of the translation of task requirements to HSI resource requirements, the procedures for developing and documenting the detailed design, and design tests and evaluations. DCD Tier 2, Section 18.8.1.7, "Task-Related Human System Interface Requirements," describes how various AP1000 HFE program elements, such as staffing assumptions, task analyses results, and functional requirements analysis and function allocations, are used as input to the design of the HSI. DCD Tier 2, Figure 18.2-3 further illustrates how various sources of information provide input to the AP1000 HSI design process.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Concept of Operations

Criterion:

The applicant should develop a concept of operations indicating crew composition and the roles and responsibilities of individual crew members based on anticipated staffing levels. The concept of operations should consider factors such as specifying the crew responsibilities for overriding automatic equipment and interacting with computerized support systems; locating personnel at a single, large workstation or individual workstations; and addressing the coordination of crew member activities.

Evaluation:

DCD Tier 2, Section 18.8.1.1, "Functional Design," provides a description of the AP1000 system specification document for the operation and control centers system. This document is described as an "umbrella document for capturing human factors requirements and providing a uniform operational philosophy and design consistency among the individual human systems interface resources." The system specification document for the operation and control centers system, as well as individual human system functional requirements documents that are developed for each HSI resource, provides mission statements and performance requirements. The mission statements provide high-level goals and main tasks to be supported by the control center or HSI resource. The functional requirements document for each HSI resource includes a specification of the cognitive activities associated with the operators' use of the HSIs.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Functional Requirements Specification

Criterion:

The applicant should develop functional requirements to address (1) the concept of operations, (2) personnel functions and tasks that support the role in the plant as derived from task, functional requirements, and staffing analyses, (3) personnel requirements for a safe, comfortable working environment. The applicant should establish requirements for various types of HSIs, including alarms, displays, and controls.

Evaluation:

Much of the staff's evaluation of this criterion is captured by the response to Criterion 2, above. In addition, the applicant's design process provides for the development of comprehensive detailed design guidance and provides sufficient information to support its standard and consistent application. DCD Tier 2, Section 18.8.1.2, "Design Guidelines," addresses the application of this process to the AP1000 guidance. This section also outlines the applicant's specific commitment to develop HSI design guidance for each HSI resource identified. In addition, it provides a general description of the content of the guidance documents, including intended scope, references to sources, instructions for use, design conventions and guidelines, and provisions for guideline deviations based on a documented rationale.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: HSI Concept Design

Criterion:

The functional requirement specification should serve as an initial source of input to the HSI design effort. The applicant should consider operating experience from predecessor designs, if applicable. The applicant should also evaluate alternative approaches to addressing HSI functional requirements. Alternative concept designs should be evaluated and the applicant should select one for further development. The applicant should identify HSI design performance requirements for components of the selected HSI concept design.

Evaluation:

The implementation plan described in DCD Tier 2, Section 18.8, "Human System Interface Design" presents the HSI design process proposed for the AP1000 design. As such, the central elements of the AP1000 HSI design processes are based on a "comprehensive model of operator performance" that incorporates information from a variety of sources (e.g., reports of problems with current control technology, studies of human performance, Westinghouse expertise, and industry experience, as discussed in the EPRI advanced light-water reactor utility requirements document (ALWR URD)).

The staff has reviewed the "rationale for each M-MIS feature" (i.e., the wall panel information station, functionally organized alarm system, compact workstations, functionally and physically organized workstation displays, computer-based procedures, and plant communication system). For each operator activity identified by the applicant (e.g., detection and monitoring, interpretation and planning, and controlling plant state), the staff reviewed the ways in which the relevant features support the activity. The staff reviewed detailed guidelines as products of the applicant design process. These documents were reviewed in terms of statements of their intended scope, references to source materials, instructions for their proper use, and procedures to be followed. One of these documents provides guidance on display design. The document contains numerous graphics and illustrations providing examples of the design principles that will further support its use by the design team, as well as references to numerous appropriate source documents, such as the Boff, "Engineering Data Compendium: Human Perception and Performance"; Smith and Mosier; Tufte, 1983; Helendar, 1988; and NUREG-0700.

The staff also reviewed an alarm system design guideline which is a comprehensive document that addresses alarms from the perspective of their role in plant operations and not simply the end-point design. The technical basis for the alarm guidance included references to numerous appropriate sources, such as EPRI 3448, ALWR URD (1989); Van Cott and Kinkade; Institute of Electrical and Electronics Engineers (IEEE) 1023-1988; NUREG-0737, NUREG-0696, NUREG-0800, NUREG-1342; and Regulatory Guide (RG) 1.97. In addition, the applicant has tested several of the HSI concepts proposed earlier for the AP1000 design such as soft controls, the wall panel information system, and computer-based alarms and procedures (see the applicant response to AP1000 RAI 620.008), thus providing evidence that alternative approaches for HSI concept designs have been employed in the HSI design process for the AP1000.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: HSI Detailed Design and Integration

Criterion:

The applicant should develop design-specific HFE design guidance (i.e., style guide). The HSI detailed design should support personnel in their primary role of monitoring and controlling the plant while minimizing personnel demands associated with the use of HSIs. The HSI detailed design should adequately address such factors as minimizing errors associated with risk-important HSIs, supporting personnel performance during minimal, nominal, and high-level staffing, the effects of fatigue on the use of the HSIs, the ability of the HSIs to be used under a full range of environmental conditions, and the ability of the HSIs to support inspection, maintenance, test, and repair.

Evaluation:

DCD Tier 2, Section 18.8.1.2, "Design Guidelines," provides a description of a set of standards and convention guideline documents that tailor generic HFE guidance to the AP1000 HSI design and define how to apply the principles. The applicant indicated that the guidelines become a tool that enables groups of people to simultaneously develop the HSI in a consistent manner in accordance with the HFE principles established for the design. These guideline documents include anthropometric guidelines, alarm guidelines, display guidelines, control guidelines, and computerized procedures guidelines. In addition, the applicant has proposed the use of design specifications for the operation and control centers system and HSI resources. These specifications provide for the design of each HSI resource, including the integration of the hardware and software to satisfy the HSI functional design requirements. To further address this criterion of HSI detailed design and integration, the applicant proposed the use of engineering tests to support the HSI design process described in DCD Tier 2. WCAP-14396, Revision 3, "Man-in-the-Loop Test Plan Description," provides additional means for addressing this criterion through the use of engineering tests to obtain empirical results about HSI design questions that could affect the final design of the HSI.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 6: HSI Tests and Evaluations

Criterion:

The applicant should conduct testing and evaluation of the HSI designs throughout the HSI development process.

Evaluation:

WCAP-14396, Revision 3, provides a description of the use of engineering tests to support the detailed HSI design process. The engineering tests proposed by the applicant for the AP1000 HSI design are preliminary tests to address the design of HSIs. This is in contrast to validation tests that are performed as part of the validation of the final HSI design to test the acceptability of the HSIs during V&V of the plant design. The tests reflect an iterative design process with the intent of identifying and correcting HSI design deficiencies before the validation of the final HSI design.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 7: Trade-Off Evaluations

Criterion:

The selection of the HSI design approaches should consider the effects of personnel task requirements, human performance capabilities and limits, HSI system performance requirements, inspection and testing requirements, maintenance requirements, the use of proven technology, and operating experience of predecessor designs. The HSI design selection process should indicate the relative benefits of design alternatives and the basis for their selection.

Evaluation:

DCD Tier 2, Section 18.8.1.8 addresses this item. DCD Tier 2 states that the HSI resources identified were selected as a starting point for meeting the information and control needs for general human activities (such as detection, planning, and control) identified in the operator decision making model described in WCAP-14695. DCD Tier 2, Figure 18.8-2, depicts the relationship between the human activities and the control room resources. For example, detection and monitoring are supported by the alarm system, the wall panel information system, the qualified data processing system (QDPS) and the plant information system. Utility requirements and the OER were the principal sources for the initial selection of HSI resources. The functional design documentation will describe the basis for all resource design decisions. The acceptability of each resource and the evaluation of design alternatives for the detailed implementation of each resource are accomplished through the test and evaluations that are performed during concept testing, engineering tests, and the final V&V. The results of testing will be used to refine the design.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 8: Performance-Based Tests

Criterion:

Various criteria constitute the development of appropriate performance-based tests. These criteria include testing based upon specific test objectives, selection of testbeds based upon the requirements of the test hypotheses and maturity of the designs, selection of appropriate test participants, selection of appropriate performance measurements, selection of an appropriate test environment, selection of appropriate test data analysis techniques, etc.

Evaluation:

WCAP-14396, Revision 3, provides the details of the various engineering tests planned to support the detailed design of the AP1000 HSI. WCAP-14396, Revision 3, Section 2.4, "General Test Plan," discusses the issues identified in this criterion, including overall test design, use of test subjects, use of performance measures and data analysis, and use of test results. WCAP-15860, Revision 2, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," also covers this topic, although to a somewhat lesser extent.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 9: HSI Design Documentation

Criterion:

The HSI design should document the following features:

- the detailed HSI description, including the format and performance characteristics
- the basis for the HSI design characteristics with respect to operating experience and literature analyses, trade-off studies, engineering evaluations and experiments, and benchmark evaluations
- records of the basis of the design changes

The applicant should document the outcomes of tests and evaluations performed in support of the HSI design.

Evaluation:

A full documentation of the AP1000 HSI is not currently available because the design is not yet completed. DCD Tier 2, Sections 18.8, "Human System Interface Design," and 18.13, "Inventory," document the current status of the MCR resources, including HSI requirements, description, and technical basis.

WCAP-15847, Revision 1, describes and controls the complete documentation process for the final AP1000 design. This topical report provides a description of the HSI documentation process. Procedure AP-3.1 in WCAP-15847 establishes requirements for system specification documents (SSDs). SSDs identify specific system design requirements and detail how the design satisfies the requirements. They provide a vehicle for documenting the design and its basis. General Step C states that the SSDs provide for the control room HSI design. Step E and Appendix C provide a list of systems for which SSDs are required, which includes the operation and control centers. Appendix A provides a table of contents for each SSD and Appendix B provides a summary description of the contents of each SSD section.

WCAP-15847, Procedure AP-3.2 discusses the change control program and provides the required process and actions to implement a design change in a document that is under configuration control. This procedure includes SSDs, drawings, etc., and provides considerable information on responsibilities, procedures, documentation, and approvals.

WCAP-15847, Procedure AP-3.6 on design criteria documents, specifies requirements for the preparation, review, approval, and revision of design criteria documents. These documents define the requirements for specific aspects of the AP1000 design, typically in a single discipline or subdiscipline. In addition, DCD Tier 2, Section 18.8.1.2, "Design Guidelines," provides a commitment from the applicant that the HFE Program will be developed using accepted industry standards, guidelines, and practices. DCD Tier 2, Section 18.8.6, "References," provides numerous citations of applicable standards, guidelines, and practices used to develop the AP1000 HSI design.

In conclusion, the applicant's design process defined in WCAP-15847 and documented and illustrated in DCD Tier 2 for the current state of the AP1000 HSI design completion will provide an acceptable documentation of the detailed HSI design. Based on its review, the staff concludes that WCAP-15847, Revision 1, is applicable to the AP1000.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.8.1.4 Conclusions

This review evaluated the process by which HSI design requirements will be developed and HSI designs will be selected and refined. The staff reviewed HSI development at an implementation plan level of detail. The review addressed the process by which function and task requirements will be translated to the displays and controls that will be available to the crew. The applicant should have a process for systematically applying HFE principles and criteria, along with all other function, system, and task design requirements, to the identification of HSI requirements, the selection and design of HSIs, and the resolution of HFE/HSI design problems and issues. The applicant should document the process and rationale for the HSI design, including the results of trade-off studies, other types of analyses and evaluations, and the rationale for selection of design and evaluation tools.

The HSI design process presented in DCD Tier 2 has many positive features, including a systematic identification of information and control requirements, as well as the systematic testing of concepts and designs. This process includes developing functional requirements and functional specifications for key components of the HSI design. This is followed by the development of physical implementation documents that guide the detailed design of software and hardware.

The staff's review of the AP1000 HSI focused strongly on the process by which the final design will be developed. Details of the guidance documents and the process by which they will be completed were important considerations in this review because the full details of the actual HSI design will not be available before design certification.

The applicant has provided an acceptable HSI design implementation plan for the AP1000 design. The COL applicant referencing the AP1000 certified design is responsible for the execution and documentation of the HSI design implementation plan. This is COL Action Item 18.8.1.4-1.

18.8.2 Safety Parameter Display System

18.8.2.1 Objectives

The objective of this review is to evaluate the way in which SPDS functions will be provided in the AP1000 control room. The review will ensure that the applicant has appropriately translated SPDS functional requirements to the displays that are available to the crew.

18.8.2.2 Methodology

18.8.2.2.1 Material Reviewed

The review focused on an evaluation of the applicant's material pertinent to the SPDS. The staff used the following Westinghouse documents in this review:

- DCD Tier 2
- WCAP-14396, Revision 3, "Man-in-the-Loop Test Plant Description," issued November 27, 2002

18.8.2.2.2 Technical Basis

The staff focused its review on an evaluation of the information provided by the applicant pertaining to the SPDS with respect to the criteria contained in 10 CFR 50.34 (f)(2)(iv), Supplement 1 of NUREG-0737, and NUREG-1342. This review considered the extent to which the applicant's design will support the functions required for the SPDS because the applicant has not completed the detailed design of the control room displays.

18.8.2.3 Results

This section discusses the results of the staff's evaluation of the SPDS of the AP1000 including general requirements, display of safety parameters, reliability, isolation, HFE, minimum information required, and procedures and training. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections:

Criterion 1: General SPDS Requirements

Criterion:

Title 10, Subsection 50.34(f)(2)(iv) of the Code of Federal Regulations contains the top-level requirements for the SPDS. The detailed NRC criteria that follow were derived from Supplement 1 of NUREG-0737.

Evaluation:

The discussion of plant safety parameters in 10 CFR 50.34(f)(2)(iv) indicates that the design should provide a plant safety parameter display console that will (1) display to operators a minimum set of parameters defining the safety status of the plant, (2) be capable of displaying a full range of important plant parameters and data trends on demand, and (3) be capable of indicating when process limits are being approached or exceeded.

As described in DCD Tier 2, Section 18.8.2, "Safety Parameter Display System," the applicant addressed the SPDS concerns and criteria with an integrated design, rather than a stand-alone, add-on system as is used at most currently operating plants. The AP1000 design will address the regulatory requirements by integrating the SPDS requirements into the design requirements for the alarm and display systems. In NUREG-0800, the staff indicated that for applicants who are in the early stages of the control room design, the "function of a separate SPDS may be integrated into the overall control room design."

Therefore, the staff has determined that the special circumstances described in10 CFR 50.12(a)(2)(ii) exist. The applicant has provided an acceptable alternative that accomplishes the intent of the regulation. The requirement for an SPDS console need not be applied in this particular circumstance to achieve the underlying purpose for an SPDS, which is to provide a control room improvement that enhances operator ability to comprehend plant conditions and interact in situations that require human intervention. The SPDS should provide a concise display of critical plant variables to control room operators to aid them in rapidly and reliably determining the safety status of the plant.

On this basis, the Commission concludes that an exemption from the requirements of 10 CFR 50.34(f)(2)(iv) for an SPDS console is authorized by law, will not present an undue risk to public health and safety, and is consistent with the common defense and security. However, for the implementation of an integrated SPDS to be acceptable, it must meet the detailed SPDS requirements reflected in this item. A discussion of these requirements follows:

- The SPDS will display to operators a minimum set of parameters defining the safety status of the plant. The SPDS will be capable of displaying a full range of important parameters and data trends on demand.

- Criterion 8 of this section reviews the minimum set of parameters required to define safety status. With respect to other "important parameters," the applicant's integrated HSI design provides parameter display to operators via the wall panel information display and the workstation displays. The applicant will provide a complete specification of the individual parameters to be displayed as the MCR design and its supporting analyses, such as FBTA and HRA, continue. The display will provide the status of the functions of reactivity control, reactor core cooling and heat removal, reactor coolant system integrity, radioactivity control, and containment. Most of the parameters used to monitor these functions are continuously displayed. Those that are not will be available in one navigation step. DCD Tier 2, Chapter 7, identifies parameters for postaccident monitoring (PAM), including those needed to monitor the CSFs.

- The ability of operators to call up data trends on demand is addressed in Section 18.9.5.

- The SPDS will be capable of indicating when process limits are being approached or exceeded. This SPDS function will be satisfied by the AP1000 alarm management system.

NUREG-0737, Supplement Number 1, 3.8.a, Items (1), (2), and (3) set forth elements of the SPDS. One acceptable way of implementation is presented, with other proposals to be reviewed as necessary.

Item (1) states that the applicant should review the functions of the nuclear power plant operating staff that are necessary to recognize and cope with rare events that pose significant contributions to risk, could cause operators to make cognitive errors in diagnosing them, and are not included in routine operator training programs.

Item (2) states that the applicant should combine the results of this review with accepted human factors principles to select parameters, data display, and functions to be incorporated into the SPDS.

Item (3) states that the applicant should then design, build, and install the SPDS in the control room and train its users.

The applicant committed to design, build, and install the SPDS in accordance with the accepted human factors principles discussed in DCD Tier 2, Section 18.8.2.5, "Human Factors Engineering." The applicant discussed the training of users in DCD Tier 2, Section 18.8.2.7, "Procedures and Training." However, training has been defined as a COL item (see DCD Tier 2, Section 18.10, "Training Program Development"). Thus, the SPDS training issue will not be addressed as part of the design certification review.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Rapid and Concise Display of Safety Parameters

Criterion:

The SPDS should provide a rapid and concise display of critical plant variables to control room operators.

Evaluation:

The requirement for a concise display stems from the lack of centralized display capability in the Three Mile Island Nuclear Station, Unit 2 (TMI-2) control room. The TMI-2 control room personnel could not easily develop an overview of plant conditions, which contributed to the severity of the accident. The applicant alarm management system is organized around the concept of plant process functions, which include the five safety functions defined by the NRC for the SPDS. The layout of these functions ensures that they are always visible.

The AP1000 will use a similar design for the wall panel information system. The individual parameters that support the safety functions will be grouped by those safety functions in both the AP1000 alarm system and the plant information system displays. The status of all five safety functions will always be displayed by the alarm system overviews that will be available to the operators through the wall panel information system. Thus, a concise display will be available which acceptably addresses this aspect of the SPDS criterion.

Meeting the criterion for a rapid display depends on sample rate, update rate, system response times, and a display format that is easy to understand and rapidly comprehended.

In DCD Tier 2, Section 18.8.2.2, "Display of Safety Parameters," the applicant stated that (1) the design goal for the graphical display response time is 2 seconds, (2) the design goal for the AP1000 HSI is to update the displays every 1 to 2 seconds, and (3) the design goal for the process data sampling is 1 second or less. The SPDS design met the criteria with the exception of response time, as explained below.

The acceptability of a display response time of 2 seconds (or, as stated in DCD Tier 2, Section 18.8.2.2, as long as 10 seconds) for operator support during transient operations may be problematic for operators. The staff recognizes that this value is within the response time originally developed for the SPDS. However, such SPDS consoles were supplemental to the available indications and controls. It is also recognized that a-2 second response time is within the time range recommended by most current HFE guidelines. However, this value is based on general literature and, therefore, may not be fully adequate for emergency operations in a process control environment such as a nuclear power plant. Delays have the potential to create frustration in operators who are accustomed to having information instantly available through continuously displayed analog instruments. The staff, therefore, recommended that the applicant verify the acceptability of the 2-second criterion, and if found unacceptable, to determine the appropriate display response time.

DCD Tier 2 indicates that most of the safety parameters used to monitor SPDS functions will be continuously displayed on the wall panel information system. Those that are not continuously displayed will be accessible from the operator's workstation with one navigation action. In addition, the applicant agreed to include the issue of response time as a design issues tracking system item and examine it in the "Man-in-the-Loop Test Program," (WCAP-14396, Revision 2). The tracking system item references the NRC letter dated September 28, 1995, in which the staff's concerns are documented. The item indicates that "the acceptability of a display response time of 2 seconds for operator support during transient operations is determined during Man-in-the-Loop testing. If 2 seconds is determined to be unacceptable, then a revised display response time is determined."

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Convenient Display of Safety Parameters

Criterion: The location of the SPDS should be convenient to the control room operators.

Evaluation:

To meet this criterion, the SPDS should be convenient to all operators/users of the SPDS. In DCD Tier 2, Section 18.8.2, "Safety Parameter Display System," the applicant indicated that the SPDS would utilize the main control alarm system and display system in order to fully integrate the SPDS into the AP1000 HSI. All process displays and controls (including the SPDS) will be available at each of the redundant operator workstations. The control room supervisor has another console that contains all of the same displays. The shift-technical advisor also has a console with all displays. Finally, the wall panel information system is a parallel display device that also contains the SPDS information, and is available and viewable by all in the control room.

Thus, the status of critical safety functions is conveniently located where it can be monitored from anywhere in the control room and is continuously displayed by the overview alarms presented on the wall panel information system. In addition, the computerized emergency operating procedures system will also display the status of critical safety functions when the system is in use.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Continuous Display of Safety Parameters

Criterion:

The SPDS should continuously display plant safety status information.

Evaluation:

In DCD Tier 2, Section 18.8.2, the applicant indicated that the status of all five safety functions is always displayed via the alarm management system. The alarm system is organized on the dark board concept for all plant modes. Thus, when no alarms are displayed, it indicates that the status of all safety functions is acceptable. The alarm system also will have failure indicators to ensure the operability of the alarm system itself. Further, the AP1000 computerized procedures for EOPs will provide a continuous display of the overall state of each of the safety functions as part of a requirement to monitor the status of the critical safety function status trees. The staff did not review the computerized procedures system proposed by the applicant for design certification.

Thus, the status of critical safety functions is conveniently located where it can be monitored from anywhere in the control room, and is continuously displayed by the overview alarms presented on the wall panel information system.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: High Reliability

Criterion:

The SPDS should have a high degree of reliability.

Evaluation:

The SPDS is to be incorporated into the AP1000 control room; however, the control room is not yet designed. In DCD Tier 2, Section 18.8.2, the applicant indicated that availability and reliability criteria will be included in the design process as is standard for Westinghouse I&C systems. The staff has determined that the applicant's response to this criterion is acceptable because the design process will ensure that a high degree of reliability will be achieved for all I&C systems, including the SPDS.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 6: Isolation

Criterion:

The SPDS should be suitably isolated from electrical or electronic interference with safety systems.

Evaluation:

In DCD Tier 2, Section 18.8.2.4, "Isolation," the applicant stated that DCD Tier 2, Chapter 7, includes a discussion of the electrical isolation for the control room. The staff reviewed the applicant's response to this criterion (i.e., that data links are fiber-optic isolated and transmit only to the monitor bus) and determined that it will provide suitable isolation of the SPDS.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 7: Human Factors Engineering

Criterion:

The SPDS should be designed incorporating accepted human factors principles.

Evaluation:

In DCD Tier 2, Section 18.8.2.5, "Human Factors Engineering," the applicant stated that the SPDS will be incorporated into the control room alarm and display systems. In accordance with the NUREG-0711 element on HSI design (evaluated herein), the staff considered the HSI design acceptable at the program plan level. The detailed implementation of SPDS displays, controls, and interface management (e.g., navigation) characteristics will not be complete until after the design certification.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 8: Minimum Information

Criterion:

The SPDS should display sufficient information to determine plant safety status with respect to the safety functions described in Table 2 of NUREG-1342.

The safety functions and parameters of Table 2 of NUREG-1342, were developed for conventional PWRs. They are still generally applicable for the AP1000, but will need to be revised slightly to address the passive plant differences.

Evaluation:

In discussing the minimum parameters for display, NUREG-1342 states that, at a minimum, information about the following safety functions must be displayed:

- reactivity control
- reactor core cooling and heat removal from the primary system
- RCS integrity
- radioactivity control
- containment conditions

Licensees and applicants will determine the specific parameters to be displayed. Tables 2 and 3 of NUREG-1342 contain sample acceptable parameters for BWRs and PWRs.

In DCD Tier 2, the applicant indicated that the alarm system, plant information system, and the computerized procedures system are the AP1000 HSI resources used to address the SPDS requirements. The staff has determined that the AP1000 HSI displays sufficient information to determine plant safety status with respect to the SPDS safety functions. Safety functions and respective parameters that are presented in Table 2 of NUREG-1342 are used as a starting point for developing the AP1000 SPDS. The applicant also committed to track the design issue of SPDS "minimum information" in the HFE issues tracking system.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 9: Procedures and Training

Criterion:

Procedures and operator training, which address actions both with and without the SPDS, should be implemented.

Evaluation:

DCD Tier 2, Section 18.8.2.7, "Procedures and Training" addresses procedures and training. This section indicates that procedures and training are the responsibility of the COL applicant (COL Action Item 18.10.3-1). Thus, review of this SPDS criterion is a postdesign certification activity.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.8.2.4 Conclusions

This review evaluated the way in which the functions of the SPDS will be provided in the AP1000 control room. The staff has completed its review of the SPDS component of Element 7 of NUREG-0711. The staff finds that the applicant has acceptably addressed all criteria for the SPDS.

18.9 Element 8: Procedure Development

18.9.1 Objectives

The objective of this review is to ensure that the applicant's procedure development program will result in procedures that support and guide human interaction with plant systems and control plant-related events and activities. Human engineering principles and criteria should be applied, along with all other design requirements, to develop procedures that are technically accurate, comprehensive, explicit, easy to use, and validated.

18.9.2 Methodology

18.9.2.1 Material Reviewed

The review focused on an evaluation of the applicant's documents with respect to the topics and general criteria of NUREG-0711. The following Westinghouse documents were used in this review:

- DCD Tier 2
- WCAP-14690, Revision 1, "Designer's Input to Procedure Development for the AP600," issued June 27, 1997
- NUREG-1512, "Final Safety Evaluation Report Related to Certification of the AP600 Standard Design"
- "Westinghouse AP600 Emergency Response Guidelines (ERGs)"

18.9.2.2 Technical Basis

Because procedure development is COL Action Item 18.9.3-1, the focus of the staff's review was to determine the acceptability of the COL action item description to evaluate applying the applicant's existing ERGs (developed for AP600) to the AP1000 design.

18.9.3 Results

This section discusses the results of the staff's evaluation of the AP1000 procedure development process. The staff evaluated how well the applicant's program met the topics and general criteria of NUREG-0711. The results of the staff's evaluation are presented below.

As stated previously, procedure development is a COL action item for AP1000.

DCD Tier 2, Section 18.9.1, "Combined License Information," refers to DCD Tier 2, Section 13.5, "Plant Procedures," for a description of the COL action item. The item states that procedure development is the responsibility of the COL applicant. Westinghouse will provide the COL applicant with WCAP-14690, Revision 1. However, it should be noted that although Westinghouse submitted this document in support of the COL's procedure development program, the staff has not evaluated the computerized procedure system identified by Westinghouse as the interface to plant procedures.

The NRC neither endorses nor rejects using the computer as a platform for presenting procedures. In the NRC's review of the EPRI URD guidance on computer-based procedures (CBPs), questions were raised concerning the basis for the computerized procedure requirement. EPRI indicated that CBP guidance is lacking and that it will have to be developed by the designer using simulation. The response by EPRI noted the following:

> Since both the 'soft' and 'hard' procedures are subject to the test of active simulation, there will inherently be a direct comparison between the 'soft' and the 'hard' procedures as part of the design process. Differences in operator performance with the computer-presented procedures compared to the conventional printed procedures should be evident from these evaluations.

Further, EPRI indicated that, "If the soft procedures are not concluded to represent an improvement when active simulation is attempted, there is a clear fall-back to hardcopy procedures."

In consideration of the EPRI URD and the subsequent response to the RAI, the staff noted in its review the following:

> The development of electronically displayed procedures is a desirable goal for the overall integration of operator information needs. The staff position is that the M-MIS designer should consider the use of electronically displayed procedures early in the design process to resolve any issues concerning their development, operability, maintainability, and reliability. If electronically displayed procedures are determined to be an improvement over hard-copy procedures and the M-MIS designer has integrated electronically displayed procedures into the overall M-MIS design, they should be provided as part of the design.

The staff's position reflected in the URD review is applicable to the use of computerized procedures by the AP1000. That is, the acceptance of these procedures will be based, in part, on the type of evaluations described above.

Evaluation of the applicant's computerized procedure system was not included in the design certification for the AP1000. WCAP-14690, Revision 1, provides information on the computer-based procedure system which will serve as the interface to the plant procedures.

While this description is acceptable, the staff has determined that it is necessary for the COL applicant to (1) address the procedure development considerations in NUREG-0711, and (2) identify the minimum documentation that the COL applicant will provide to the staff to complete its review. This is COL Action Item 18.9.3-1.

In addition to the information provided in DCD Tier 2, Sections 18.9.1, "Combined License Information," and 13.5, "Plant Procedures," the staff assessed the applicability of the applicant's existing ERGs to the AP1000 design. The ERGs (or generic technical guidelines) are evaluated in the following paragraphs as an important input to procedure development. The acceptability of other bases for the development of AP1000 procedures (e.g., task analysis results, risk-important human actions) is addressed in other elements of the design review.

DCD Tier 2, Section 18.9, states that WCAP-14690 provides input to the COL applicant for the development of plant operating procedures, including information on the development and design of the ERGs and EOPs which apply to the AP1000. Also, DCD Tier 2, Sections 19E.1.2 and 19E.3.3 reference the applicant's existing ERGs to address the shutdown operations issues for the AP1000 design, and state that the applicant's existing ERGs are applicable to the AP1000 for the purpose of developing EOPs.

In response to the staff's requests for technical justification of the applicability of the applicant's existing ERGs to the AP1000 design, the applicant provided the following reasons:

- The existing ERGs (developed for the AP600) are applicable to the AP1000 for the purposes for which they are intended, that is, to provide the starting point for the development of the EOPs as part of the HFE process. The ERGs provide symptom-based, as opposed to event-based, guidance to the operator. For that reason, the ERGs do not immediately instruct the operator to attempt to diagnose an event. The ERGs guide the operator to assess the plant parameters and operability of the available systems, and provide the most straightforward direction to the operator.

- The AP600 and AP1000 employ the same passive safety-related systems. These systems significantly reduce the burden on the operator in an accident scenario as compared to currently operating reactors. The designs of the AP600 and AP1000 are functionally the same with respect to the role of the passive safety systems and active systems provided for defense-in-depth. The symptom-based approach contained in the applicant's existing ERGs allow them to be used as the starting point to develop the detailed EOPs as part of the HFE design process for the AP1000.

- The use of existing ERGs for the AP1000 is similar to the implementation of the standard ERGs for Westinghouse operating plants. Because the ERGs are symptom-based, the functional guidance they provide is applicable to a range of plant designs that functionally perform in a similar manner. For example, the Westinghouse standard ERGs can apply to 2-loop, 3-loop or 4-loop plants that contain a range of nuclear steam supply system (NSSS) and balance of plant system design features. Therefore, it is reasonable to expect that the applicant's existing ERGs can be used as the starting point for the development of the AP1000 EOPs.

- The analysis provided in the ERGs background documentation is suitable, as it provides an example of the role of the operator in performing actions outlined in the ERGs. The timing of the specific accidents analyzed may be slightly different for two plants; however, the response of the operator to any particular plant symptom or system will be similar.

The staff has reviewed the above technical justification and agrees with the applicant's assessment that its existing ERGs could be applied to the AP1000 design for the development of adequate EOPs using proper HFE procedures.

18.9.4 Conclusions

This review ensured that the applicant's procedure development program will result in procedures that support and guide human interaction with plant systems, as well as control plant-related events and activities. Human engineering principles and criteria should be applied along with all of the other design requirements, to develop procedures that are technically accurate, comprehensive, explicit, easy to use, and validated.

Procedure development is a COL action item and will be addressed by the COL applicant as part of the postdesign certification issues. This is COL Action Item 18.9.3-1.

18.10 Element 9: Training Program Development

18.10.1 Objectives

A systems approach to training, as defined in 10 CFR 55.4, is required of plant personnel by 10 CFR 52.78(b) and 10 CFR 50.120. A systematic analysis of job and task requirements should serve as the basis for the training design. The HFE analyses associated with the HSI design process provide a valuable understanding of the task requirements of operations personnel. Therefore, training program development should be coordinated with the other elements of the HFE design process. The objective of this review is to ensure that the COL applicant establishes an approach for the development of personnel training that incorporates the elements of a systems approach, which consists of the following:

- a systematic analysis of tasks and jobs performed
- development of learning objectives derived from an analysis of desired performance following training
- design and implementation of training based on the learning objectives
- evaluation of trainee mastery of the objectives during training
- evaluation and revision of the training based on the performance of trained personnel in the job setting

18.10.2 Methodology

18.10.2.1 Material Reviewed

The staff used the following Westinghouse documents in this review:

- DCD Tier 2
- WCAP-14655, Revision 1, "Designer's Input for the Training of Human Factors Engineering Verification and Validation Personnel," issues August 8, 1996

18.10.2.2 Technical Basis

The focus of the staff's review was to determine the acceptability of the description of the COL action item with respect to the topics and review criteria of Element 10, "Training Program Development," of NUREG-0711.

18.10.3 Results

DCD Tier 2, Section 18.10.1, "Combined License Information," refers to DCD Tier 2, Section 13.2, "Training," for a description of the COL action item. The item states that the development of a training program is the responsibility of the COL applicant. The applicant will provide the COL applicant with WCAP-14655, Revision 1, which provides information on how insights are passed from the designer to the COL applicant. While this description is acceptable, the staff has determined that it is necessary for the COL applicant to (1) address the training program development considerations in NUREG-0711, (2) address relevant concerns identified in this report, and (3) identify the minimum documentation that the COL applicant will provide to the staff to complete its review. Based on its review, the staff concludes that WCAP-14655, Revision 1, and the associated COL action item are applicable to AP1000. This is COL Action Item 18.10.3-1.

18.10.4 Conclusions

The staff's review of the applicant's training program ensured that the applicant established an approach for developing personnel training that incorporates the elements of a systems approach to training, evaluates the knowledge and skill requirements of personnel, coordinates training program development with the other elements of the HFE design process, and implements the training in an effective manner that is consistent with human factors principles and practices.

Development of a training program is a COL action item and will be addressed by the COL applicant as part of the postdesign certification issues. This is COL Action Item 18.10.3-1.

18.11 Element 10: Human Factors Verification and Validation

18.11.1 Objectives

The objective of this review is to ensure the following:

- the HFE/HSI design provides all necessary alarms, displays, and controls to support plant personnel tasks
- the HFE/HSI design conforms to HFE principles, guidelines, and standards
- the HFE/HSI design can be effectively operated by personnel within all performance requirements
- the HFE/HSI design resolves all of the identified HFE issues

18.11.2 Methodology

18.11.2.1 Material Reviewed

The staff used the following Westinghouse documents in this review:

- DCD Tier 2
- WCAP-14396, Revision 3, "Man-in-the-Loop Test Plan Description," issues November 27, 2002
- WCAP-15860, Revision 2, Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," issued October 2003
- WCAP-15847, Revision 1, "AP1000 Quality Assurance Procedures Supporting NRC Review of AP1000 DCD Section 18.2 and 18.8," issued December 2002

18.11.2.2 Technical Basis

The staff focused its review on an evaluation of the applicant's documents with respect to the topics and general criteria of Element 11, "Human Factors Verification & Validation," of NUREG-0711.

The applicant did not submit a detailed V&V implementation plan for design certification. Detailed V&V procedures were not developed for design certification. The staff reviewed the applicant's V&V description at a programmatic review level because completion of an implementation plan is a COL action item and will not be completed until after the design certification.

The staff reviewed Element 10 of NUREG-0711 at a programmatic review level; therefore, detailed evaluations using NUREG-0711 acceptance criteria are beyond the scope of the staff review for design certification. At a programmatic level review, the staff uses the NUREG-0711 criteria to determine whether the applicant's program provides a top-level identification of the substance of each criterion which, after design certification, a COL applicant can employ to develop a detailed implementation plan. The ITAAC which exist for completing the implementation plan also describe the applicant's commitment to the development of such a detailed implementation plan.

18.11.3 Results

The staff reviewed the general criteria for V&V—operational condition sampling; design verification (HSI task support verification and HFE design verification); integrated system validation; and human engineering discrepancies resolution. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections:

18.11.3.1 Operational Conditions Sampling

Criterion 1: Sampling Dimensions

The sampling methodology will identify a range of operational conditions to guide V&V activities. The sample of operational conditions should (1) include conditions that are representative of the range of events that could be encountered during operation of the plant, (2) reflect the characteristics that are expected to contribute to system performance variation, and (3) consider the safety significance of HSI components.

Criterion 1-1:

The sampling methodology should include normal events including plant startup, plant shutdown or refueling, and significant changes in operating power, failure events, transients and accidents, and reasonable risk-significant, beyond-design-basis events.

Evaluation:

In WCAP-15860, Revision 2, Section 1.2, "General Scope of AP1000 V&V," the applicant indicated that the operational sequences that will be included in V&V will cover a full range of activities including startup, normal operations, abnormal and emergency operations, transient conditions, low-power, and shutdown conditions. The V&V scope will include those tasks determined to be risk-important as defined by the PRA threshold criteria specified in the implementation plan for the integration of HRA and HFE design. WCAP-15860, Revision 2, Section 4.6, "Criteria for Evaluation of Test Scenarios for Dynamic Evaluations," contains further detail related to addressing this criterion.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 1-2:

The HFE V&V program should include risk-significant human actions, systems, and accident sequences; OER-identified difficult tasks; the range of procedure-guide tasks; the range of knowledge-based tasks; the range of human cognitive activities; and the range of human interactions.

Evaluation:

In addition to the evaluation of Criterion 1-1 above, WCAP-15860, Revision 2, Section 4.6, contains further details related to addressing this criterion, such as using scenarios that produce cognitive challenges or that are sufficient to validate the EOPs, as well as key HRA modeling assumptions. WCAP-14396, Revision 3, Section 2.4, "General Test Plan," provides additional information.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 1-3:

The sampling methodology should reflect a range of situational factors that are known to challenge human performance, such as operationally difficult tasks, error-forcing contexts, high workload conditions, varying workload situations, varying fatigue and circadian factors, and environmental factors.

Evaluation:

In addition to the evaluation of Criteria 1-2 above, WCAP-15860, Revision 2, Section 4.6, contains further detail related to addressing this criterion, particularly in terms of factors such as high workload. Section 4.7, "Realistic Validation Scenarios," addresses issues related to environmental factors.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Scenario Identification

Criterion 2-1:

The results of sampling should be combined to identify a set of scenarios to guide subsequent analyses.

Evaluation:

WCAP-15860, Revision 2, Section 4.6, "Criteria for Evaluation of Test Scenarios for Dynamic Evaluations," indicates that a multidimensional set of criteria will be used to define a set of test scenarios to be included in the AP1000 integrated system validation.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2-2:

Scenarios should not be biased towards those in which only positive outcomes can be expected, those which are relatively easy to conduct administratively, and those which focus on "textbook" design accidents.

Evaluation:

WCAP-15860, Revision 2, Section 4.6, "Criteria for Evaluation of Test Scenarios for Dynamic Evaluations," indicates that the set of test scenarios encompassed by the integrated system validation will be defined by a multi disciplinary team that includes input from EOP developers, HSI designers, human factors specialists, and HRA/PRA analysts. Sections 4.7, "Realistic Validation Scenarios," and 4.8, "Performance Measures and Acceptance Criteria," provide further information to address this criterion.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.11.3.2 Inventory and Characterization

Criterion 1: Scope

Criterion 1-1:

The applicant should develop and inventory all HSI components associated with the personnel tasks that are required based on the identified operational conditions.

Evaluation:

In DCD Tier 2, Section 18.8.1.7, "Task-Related Human System Interface Requirements," the applicant discussed the process of operational sequence analysis which is comparable to a traditional task analysis. One type of information provided by the OSA is an inventory of alarms, controls, and parameters needed to perform the task sequences.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: HSI Characterization

Criterion:

The inventory should describe the characteristics of each HSI component within the scope of the review, including the unique identification code number or name, associated plant system and subsystem, associated personnel function/subsystem, type of HSI component, display characteristics and functionality, control characteristics and functionality, user-system interaction and dialog type, location in the data management system, and physical location of the HSI, if applicable. The inventory should also include photos, copies of video display unit screens, and samples of HSI components.

Evaluation:

Although the applicant does not address the specific characteristics of each component identified in the inventory of HSIs developed as part of the design process, the set of documents that the applicant described in DCD Tier 2, Section 18.8.1, "Implementation Plan for the Human System Interface Design," as an output of the functional design, provide assurance that the characteristics needed for a satisfactory description of an HSI inventory are present. The applicant has a comprehensive set of HSI design documents that specify the mission, design bases, performance requirements, and functional requirements for each HSI.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Information Sources

Criterion:

The HSI inventory should be based on the best available sources (e.g., equipment lists, design specifications, and drawings).

Evaluation:

In DCD Tier 2, Section 18.8.6, "References," the applicant provided an acceptable listing of contemporary sources that will be used in compiling HFE guidelines, standards, and principles to be included in the AP1000 design guidance.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.11.3.3 HSI Task Support Verification

Criterion 1: Criteria Identification

Criterion:

The criteria for task support verification come from task analyses of HSI requirements for performance of personnel tasks.

Evaluation:

WCAP-15860, Revision 2, Section 2, "HSI Task Support Verification," indicates that the AP1000 HSI task support verification implementation plan will include a check against the information and control requirements identified by the function-based task analysis and operational sequence tasks analysis.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: General Methodology

Criterion:

The applicant should compare the HSIs and their characteristics to the personnel task requirements identified in the task analysis.

Evaluation:

In WCAP-15860, Revision 2, the applicant described its approach to HSI task support verification. Section 2 of this document identified the objective and high-level methodology for conducting the evaluation. The analysis will address the availability of HSI features for accomplishing personnel tasks and actions, as defined by the task analyses, the EOPs, and the risk-important human tasks identified by the PRA.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Task Requirements Deficiencies

Criterion:

Human Engineering Discrepancies (HEDs) should be identified when an HSI needed for task performance is not available, or when HSI characteristics do not match personnel task requirements.

Evaluation:

WCAP-15860, Revision 2, Section 5, "Issue Resolution Verification," indicates that an implementation plan will be developed to ensure that all human factors issues are adequately addressed in the final HSI design.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Unnecessary HSI Components

Criterion:

The applicant should verify that the HSI does not include information, displays, controls, etc. that do not support operator tasks. This includes nonfunctional, decorative details, such as borders and shadowing on graphical displays.

Evaluation:

In WCAP-15860, Revision 2, the applicant described its approach to HSI task support verification. Section 2 of WCAP-15860 identified the objective and high-level methodology for conducting the evaluation. The plan also indicated that the methodology shall describe how the HSI design will be verified in each case to ensure that the HSI does not include information, controls, and displays that do not support operator tasks. A process for checking such HSI features will include an analysis before any information is removed from the HSI.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.11.3.4 HFE Design Verification

Criterion 1: Criteria Identification

Criterion:

The HFE guidelines serve as review criteria. Selection of specific guidelines depends on the characteristics of the HSI components included in the scope of review and whether the applicant has developed a design-specific guideline document. NUREG-0700 may be used for HFE design verification.

Evaluation:

In WCAP-15860, Revision 2, the applicant described its general approach to HFE design verification. Section 3 of this topical report identifies the objective and high-level methodology for conducting the evaluation. The analysis will verify that all aspects of the HSI are consistent with accepted HFE guidelines, standards, and principles. The verification will utilize AP1000-specific guidance documents and will cover alarms, displays, controls, data processing, navigation, computerized procedures, workstation and console configurations, and anthropometric considerations and their integration. The report identifies an illustrative subset of the documents that will be used in the development of the AP1000-specific guidance. It includes the most recent control room design guidance, including International Electrotechnical Commission (IEC) 964 and NUREG-0700, Revision 2. The plan also identifies the process by which guideline deviations will be addressed and their technical basis documented.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: General Methodology

Criterion:

The applicant should compare the characteristics of the HSI components with the HFE guidelines to determine whether the HSI is acceptable or discrepant (i.e., an HED). Discrepancies should be evaluated as potential indicators of additional issues.

Evaluation:

In WCAP-15860, Revision 2, the applicant described its general approach to HFE design verification. Section 3 of WCAP-15860, Revision 2, identifies the objective and high-level methodology for conducting the evaluation. The applicant indicated that the design implementation plan will specify a process by which deviations from accepted HFE guidelines, standards, and principles will be identified and acceptably justified based on a documented rationale. AP1000-specific HSI standards and convention guidelines will provide documentation of any deviations from accepted HFE guidelines, standards, and principles.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: HED Documentation

Criterion:

The applicant should document HEDs in terms of the HSI component involved and how the characteristics depart from a particular guideline.

Evaluation:

Open Item 18.11.3.4-1 in the DSER identified that further detail was needed regarding the process the applicant will use to document HEDs. This open item is related to Open Item 18.11.3.6-1 in Section 18.11.3.6, "Human Engineering Discrepancy Resolution," of this report.

Based on the staff's evaluation of Open Item 18.11.3.6-1, Open Item 18.11.3.4-1 is resolved and this NUREG-0711 criterion is satisfactorily addressed.

18.11.3.5 Integrated System Validation

Criterion 1: Test Objectives

Criterion:

The methodology for integrated system validation should address the following items:

- general objectives
- test objectives
- validation testbeds
- plant personnel
- scenario definition
- performance measurement
- test design
- data analysis and interpretation
- validation conclusions

Evaluation:

In WCAP-15860, Revision 2, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," the applicant described its general approach to integrated system validation. Section 4 of this topical report identifies the objective and high-level methodology for conducting the evaluation. Section 4.1 details the aspects of the methodology that will be addressed in the implementation plan. Also included are the topics identified in NUREG-0711. In addition, the plan addresses the process by which results will be used to evaluate potential design changes and, when made, their subsequent verification.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 2: Validation Testbeds

Criterion:

Validation should be performed by evaluating dynamic task performance using tools that are appropriate to the accomplishment of this objective. The primary tool for this purpose is a simulator (i.e., a facility that physically represents the HSI configuration and that dynamically reflects the operating characteristics and responses of the plant design in real time).

The requirement to validate performance of plant HSIs outside the control room will depend upon the applicant's design. Human actions at non-control-room facilities, such as remote shutdown panels and LCSs, may be evaluated using mockups, prototypes, or similar tools.

Evaluation:

In WCAP-15860, Revision 2, the applicant described its general approach to integrated system validation. Section 4.2 of topical report addresses the tools for evaluating dynamic task performance. The applicant will use a "near full-scope," high-fidelity simulator that satisfies the general requirements of Sections 3 and 4 of American National Standards Institute (ANSI)/American Nuclear Society (ANS)-3.5-1998. "Near" indicates that those features of the simulation not relevant to the tests being performed may not be high-fidelity. Personnel actions that are performed at non-control-room facilities, such as remote shutdown panels and the TSC, may be evaluated using static mockups or prototypes.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 3: Plant Personnel

Criterion:

Participants in validation tests should (1) represent an unbiased sample, (2) represent actual plant personnel, (3) reflect characteristics of the population of plant personnel; including shift supervisors, reactor operators, shift technical advisors, etc., and (4) include minimum and normal crew configurations.

Evaluation:

In support of the AP1000 design, the applicant submitted WCAP-14396, Revision 3, "Man-in-the-Loop Test Plan Description." Section 2.4.3, "Subjects," of this topical report addresses the composition of the "target user population," or the test subject population. While WCAP-14396, Revision 3, addresses preliminary or "engineering" tests, rather than final or "validation" tests (WCAP-15680 addresses validation tests), the test subject selection criteria are applicable to test subjects for both test types. Open Item 18.11.3.5-1 in the DSER identifies that the applicant should amplify/clarify or explain how validation tests address this NUREG-0711 item.

In its July 1, 2003, response to this open item, the applicant indicated that it would revise WCAP-15860 to address the concerns raised. Section 4.9, "Subjects," of WCAP-15860, Revision 1, contains information that addresses this open item. For example, the applicant discussed how test subjects will be selected to ensure an unbiased sample is used for validation testing and how test subjects will be uniformly trained before testing occurs. Therefore, Open Item 18.11.3.5-1 is resolved.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 4: Scenario Definition

Criterion:

The validation scenarios should be realistic. Selected scenarios should include environmental conditions, such as noise and distractions, which may affect human performance in an actual nuclear power plant. For actions outside of the control room, the performance impacts of potentially harsh environments (e.g., high radiation) that require additional time should be realistically simulated (e.g., time to don protective clothing and access hot areas should be included). Dynamic evaluations should evaluate the HSI under a range of operational conditions and upsets, and should include the following events:

- normal plant evolutions (e.g., startup, full power, and shutdown operations)
- instrument failures (e.g., the solid state logic control unit, fault tolerant controller, local "field unit" for the multiplexer system, or a break in an MUX line)
- HSI equipment and processing failure (e.g., loss of video display units, data processing, or the large overview display)
- transients (e.g., turbine trip, loss of offsite power, station blackout, loss of all feedwater, loss of service water, loss of power to selected buses or main control room power supplies, or safety relief valve transients)
- accidents (e.g., main steamline break, positive reactivity addition, control rod insertion at power, control rod ejection, anticipated transient without scram, or various sized loss-of-coolant accidents)
- reactor shutdown and cooldown from the remote shutdown panel

Evaluation:

In WCAP-15860, Revision 2, the applicant described its general approach to integrated system validation. Section 4.7 of this topical report addresses how the scenarios selected for validation will be made realistic. The description identifies necessary considerations regarding the incorporation of environmental conditions, communication demands, and the number of personnel in the control room. In WCAP-15860, Revision 2, Section 4.6, discusses the selection of test scenarios. Test scenarios will be defined using a multidimensional set of criteria. The dimensions are identified and include all of the types of scenarios identified in NUREG-0711. In addition, the applicant identified design features that are specific to the AP1000 such as the ADS; situations that are cognitively challenging to the crew such as complicated situation assessment under conflicting plant state information; and scenarios that would enable validation of key HRA assumptions.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 5: Performance Measurement

Criterion:

Performance measures should exhibit a number of characteristics to ensure that they are of good quality such as construct validity, diagnosticity, objectivity, impartiality, reliability, resolution, sensitivity, simplicity, and unintrusiveness. A hierarchical set of performance measures should be selected which includes measures of the performance of the plant and personnel.

Performance measures for dynamic evaluations should be adequate to test whether all objectives, design goals, and performance requirements were achieved, and should include, at a minimum, the following items:

- system performance measures relevant to plant safety
- crew primary task performance (e.g., task times and procedure violations)
- crew errors
- situation awareness
- workload
- crew communications and coordination
- dynamic anthropometry evaluations
- physical positioning and interactions

Evaluation:

In WCAP-15860, Revision 2, the applicant described its general approach to integrated system validation. Section 4.8 of this topical report discusses performance measurement and includes the aspects of integrated system performance identified in NUREG-0711. The applicant indicated that the implementation plan will define the process by which objective acceptance criteria are developed for each measure.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 6: Test Design

Criterion:

Tests used for V&V should address such characteristics as ensuring that important aspects of scenarios are balanced across crews; detailed, clear, and objective procedures are available to conduct the tests; testing administration personnel are appropriately trained; participant training is "high-fidelity" and is not focused on training to perform validation scenarios; the level of training should result in performance that is at/near the level of performance expected of actual plant personnel; and pilot testing should be conducted to assess the adequacy of the test design before conducting integrated testing.

Evaluation:

WCAP-15860, in combination with WCAP-14396, Revision 3, "Man-In-The-Loop Test Plan Description," Section 2.4, "General Test Plan," addresses this criterion. While WCAP-14396, Revision 3, discusses preliminary or "engineering" tests, rather than final or "validation" tests (WCAP-14860 addresses validation tests), elements of the general test plan should be applicable to both test types. Open Item 18.11.3.5-2 in the DSER identified that the applicant should indicate the applicability of the general test plan to validation tests or provide further detail on this criterion in either DCD Tier 2, Section 18.11 or in WCAP-15860.

In its July 1, 2003, response to this open item, the applicant indicated that a section would be added to WCAP-15860 to address the topic of validation tests. The applicant addressed this open item in Section 4.10, "Validation Test Design," of WCAP-15860, Revision 1. For example, the applicant described characteristics of the validation test design such as establishing the minimum number of test runs for each scenario of a test set, what constitutes a test set, and make-up of the crews tested. Therefore, Open Item 18.11.3.5-2 is resolved.

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

Criterion 7: Data Analysis and Interpretation

Criterion:

Validation test data should be analyzed using a combination of quantitative and qualitative methods. For pass/fail performance measures, failed indicators must be resolved before the design can be validated. In addition, the degree of convergent validity should be evaluated; data analyses should be independently validated for correctness, and any inferences drawn from comparing observed performance to estimated real-world performance should allow for margins of error (i.e., actual performance may be more variable than observed test performance).

Evaluation:

WCAP-15860, in combination with WCAP-14396, Revision 3, "Man-In-The-Loop Test Plan Description," Section 2.4, "General Test Plan," addresses this criterion. While WCAP-14396, Revision 3, discusses preliminary or "engineering" tests, rather than final or "validation" tests (WCAP-15860 addresses validation tests), elements of the general test plan should be applicable to both test types. Open Item 18.11.3.5-3 in the DSER identified that the applicant should indicate the applicability of the general test plan (see Section 2.4.2, "Measures and Analysis") to validation tests or provide further detail on this criterion in either DCD Tier 2, Section 18.11 or in WCAP-15860.

In its July 1, 2003, response to this open item, the applicant indicated that it would revise WCAP-15860 to address this concern. In WCAP-15860, Revision 1, the applicant did not add Section 4.11, "Data Analysis," to address this open item, as indicated in its July 1, 2003, response. By letter dated October 16, 2003, the applicant submitted WCAP-15860, Revision 2, which did include Section 4.11. Section 4.11 detailed several performance measures that will be collected and used to generate results from testing trials. Examples of these are included in WCAP-14396.

Based on this information, WCAP-15860, Revision 2, satisfactorily addresses this NUREG-0711 criterion. Therefore, Open Item 18.11.3.5-3 is resolved.

Criterion 8: Validation Conclusions

Criterion:

The applicant should clearly document the statistical and logical bases for determining that the performance of the integrated system is and will be acceptable. The applicant should also document any limitations of the validation tests and their potential effects on test conclusions.

Evaluation:

WCAP-15860, in combination with WCAP-14396, Revision 3, "Man-In-The-Loop Test Plan Description," Section 2.4, "General Test Plan," addresses this criterion. While WCAP-14396, Revision 3, discusses preliminary or "engineering" tests, rather than final or "validation" tests (WCAP-15860 addresses validation tests), elements of the general test plan (see Sections 2.4.6, "Use of Results," and 2.4.8, "Documentation") should be applicable to both test types. Open Item 18.11.3.5-4 in the DSER identified that the applicant should indicate the applicability of the general test plan (see DCD Tier 2, Section 2.4.2, "Measures and Analysis") to validation tests or provide further detail on this criterion in either DCD Tier 2, Section 18.11 or in WCAP-15860.

In its July 1, 2003, response to this open item, the applicant indicated that it would revise WCAP-15860 to address this concern. In WCAP-15860, Revision 1, the applicant did not add Section 4.12, "Results and Documentation," to address this open item. By letter dated October 16, 2003, the applicant submitted WCAP-15860, Revision 2, which did include Section 4.12, "Results and Documentation." Section 4.12 indicated that the test design will have a description of its basis for determining integrated systems performance is acceptable. Inherent limitations and their effects on test conclusions will be included in the results and documentation of validation conclusions.

Based on this information, WCAP-15860, Revision 2, satisfactorily addresses this NUREG-0711 criterion. Therefore, Open Item 18.11.3.5-4 is resolved.

18.11.3.6 Human Engineering Discrepancy Resolution

In WCAP-15860, the applicant described its general approach to HED resolution. Section 5 of WCAP-15860 provides the applicant's commitment to develop a procedure to verify that all issues documented in the HFE issue tracking system are completely addressed in the final HSI. In Open Item 18.11.3.6-1 in the DSER, the staff identified the need for further detail about the process the applicant will use to identify, analyze, prioritize, evaluate, document, determine, and evaluate design solutions for HEDs using the HED resolution review criteria in NUREG-0711 as a template.

In its July 1, 2003, response to this open item, the applicant indicated that it would revise WCAP-15860 to address this open item. In WCAP-15860, Revision 1, the applicant did not add Section 5, "Issue Resolution Verification," to address this open item. By letter dated October 16, 2003, the applicant submitted WCAP-15860, Revision 2, which did include Section 5, "Issue Resolution Verification," to address HED tracking and resolution. For example, Section 5 discusses how HEDs will be tracked and resolved and the role of the COL applicant in addressing HEDs.

Based on this information, WCAP-15860, Revision 2, satisfactorily addresses this NUREG-0711 criterion. Therefore, Open Item 18.11.3.6-1 and related Open Item 18.11.3.4-1 are resolved.

18.11.4 Conclusions

The V&V review was conducted at a program plan level of detail, and was directed toward determining whether the program plan addressed NUREG-0711 criteria at a high level. The V&V was judged acceptable at a programmatic level. The staff expects the V&V program to be developed in greater detail in the implementation plan. The COL applicant referencing the AP1000 certified design has the responsibility for developing, documenting, and executing the implementation plan for the V&V of the AP1000 HFE Program. This is COL Action Item 18.11.4-1.

18.12 Element 11: Design Implementation

18.12.1 Objectives

The objective of this review is to ensure the following:

- the applicant's implementation of plant changes considers the effect on personnel performance and provides the necessary support to ensure safe operations
- the applicant's as built design conforms to the verified and validated design that resulted from the HFE design process

18.12.2 Methodology

18.12.2.1 Material Reviewed

The staff reviewed the following material:

- DCD Tier 2

18.12.2.2 Technical Basis

The staff focused its review on an evaluation of the Westinghouse DCD Tier 2 with respect to the general criteria and topics of NUREG-0711, Element 12, "Design Implementation."

18.12.3 Results

The applicant indicated in DCD Tier 2, Section 18.13, that those portions of this element that apply to new plant designs, rather than issues of plant modernization, are addressed in Section 18.11 of DCD Tier 2, as "Issue Resolution Verification" and "Final Plant HFE Verification."

This is acceptable to the staff. The staff's evaluation of these criteria is provided in Element 10, "Human Factors Verification and Validation," of this section.

18.12.4 Conclusions

This review ensured that the applicant's implementation of plant changes considers the effects on personnel performance and provides the necessary support to ensure safe operations. In addition, it ensured that the applicant's design conforms to the verified and validated design that resulted from the HFE design process. The applicant acceptably addressed this review element as part of Element 10, "Human Factors Verification and Validation."

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.13 Element 12: Human Performance Monitoring

18.13.1 Objectives

The objective of this review is to determine that the applicant has prepared a human performance monitoring strategy for ensuring that no significant safety degradation occurs because of any changes that are made in the plant and to provide adequate assurance that the conclusions that have been drawn from the evaluation remain valid over time.

18.13.2 Methodology

18.13.2.1 Material Reviewed

The staff reviewed the following material:

- DCD Tier 2
- WCAP-15860, Revision 2, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan"

18.13.2.2 Technical Basis

The staff focused its review on an evaluation of the Westinghouse DCD Tier 2 with respect to the general criteria and topics of NUREG-0711, Element 13, "Human Performance Monitoring."

18.13.3 Results

This element of NUREG-0711 is the responsibility of the COL applicant. The performance monitoring strategy and program will be developed after design certification. This is COL Action Item 18.13-1.

18.13.4 Conclusions

Based on this information, the staff finds that DCD Tier 2 acceptably addressed this NUREG-0711 criterion.

18.14 Element 13: Minimum Inventory

As part of the general resolution of the issue pertaining to lack of control room detail, the staff requested that applicants for design certification identify the minimum group of fixed-position CDAs that are required for transient and accident mitigation. DCD Tier 1, Tables 2.5.2-5 and 2.5.4-1, and DCD Tier 2, Table 18.12.2-1 contain information regarding the minimum inventory for the AP1000. It should be noted that the inventory is described as a "minimum" inventory to indicate that an applicant can add to it but cannot delete from it without rulemaking.

18.14.1 Objectives

The objective of this review is to ensure that the analysis of the ERGs and operator actions determined to be significant contributors to plant risk by PRA analyses, result in an acceptable minimum inventory of fixed-position CDAs for transient and accident mitigation.

18.14.2 Methodology

18.14.2.1 Material Reviewed

The staff reviewed the following material:

- DCD Tier 2
- WCAP-14651, Revision 2, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan"
- AP600 Emergency Response Guidelines, Revision 2
- AP600 Emergency Response Guidelines Background Documents, Revision 2
- List of AP600 critical actions contained in WCAP-14651, Revision 2

18.14.2.2 Technical Basis

The review focused on evaluating the applicant's submitted material to ensure that the proposed methodology met the staff's request for a minimum inventory and that it was properly carried out by the applicant. RG 1.97, Revision 3, was used to support the identification of minimum inventory instrumentation.

18.14.3 Results

This section discusses the results of the staff's evaluation of the AP1000 minimum inventory process including the scope of minimum inventory, development of actual items, operator tasks, HFE input, task analysis input, and development of the remote work station minimum inventory. For each of these, the staff identified the relevant NUREG-0711 criteria and evaluated how well the applicant's program met them. The results of the staff's evaluation are presented in the following sections.

Criterion 1: Scope of Minimum Inventory

Criterion:

The inventory should provide criteria that define a reasonable, minimum set of fixed-position CDAs to adequately implement the ERGs for the AP1000 design, account for the critical operator actions identified in the AP1000 PRA, and mitigate transients and accidents associated with the ERGs and the PRA sensitivity study results.

Evaluation:

In DCD Tier 2, Section 18.12.2, the applicant submitted its methodology for determining the minimum inventory, as well as the results of the method. The AP1000 is designed such that the primary CDAs are computer-based and "soft." Soft controls and displays are software-defined and can be changed to perform different functions. Their locations are not dedicated like hard controls and displays. DCD Tier 2, Chapter 18, describes and justifies the rationale for this design choice which is based upon a combination of operating experience, research, and testing.

In addition to the soft controls and displays, the applicant has committed to providing a minimum set or inventory of dedicated or fixed-position instrumentation. As described in DCD Tier 2, Section 18.12.2, this minimum inventory is used to (1) monitor the status of CSFs, (2) manually actuate the safety-related systems that achieve these CSFs, and (3) establish and maintain safe-shutdown conditions. These fixed-position CDAs are available at a fixed location. They are continuously available, but not necessarily continuously displayed to the operator. The staff finds this to be an acceptable approach.

In DCD Tier 2, Section 18.12.2, the applicant described the characteristics or selection criteria which it used to develop the minimum inventory. The five criteria follow:

(1) RG 1.97, Types A, B, and C, Category 1 instrumentation

(2) dedicated controls for manual safety-related system actuation (reactor trip, turbine trip, and engineered safety feature actuation)

(3) controls, displays, and alarms required to perform critical manual actions as identified from the PRA analysis

(4) alarms provided for operator use in performing safety functions to respond to design-basis events for which there are no automatically-actuated safety function

(5) controls, displays, and alarms necessary to maintain the emergency operating procedures for critical safety functions and safe-shutdown conditions

These characteristics or criteria address a reasonable minimum set of fixed-position CDAs for the minimum inventory. In developing the minimum inventory for the AP1000, the applicant employed the process approved in earlier design certification rulemakings.

However, for AP1000, the applicant removed the "Containment Hydrogen Igniter" display from the minimum inventory (see DCD Tier 1, Tables 2.5.2-5, and 2.5.4-1, and DCD Tier 2, Table 18.12.2-1). In response to the staff's AP1000 RAI 620.005, the applicant explained that removal of the display was justified because there is a long time available before excessive hydrogen can be generated (72 hours after fuel meltdown) and the corresponding operator response to fuel failure (starting the igniters) is required. Because hydrogen igniters are discrete-state devices and are not adjusted in response to hydrogen levels, the ERGs do not use containment hydrogen concentration as a cue to either initiate or control hydrogen igniters. Instead, an indication to start the hydrogen igniters is based on core exit temperature, which remains in the minimum inventory. Since fixed-position display of hydrogen concentration is not required for emergency operation, it was removed from the inventory. The staff finds this rationale to be acceptable.

The process used to develop the AP1000 minimum inventory and the resulting minimum inventory, as described in DCD Tier 2 and the applicant's response to AP1000 RAI 620.005, acceptably addresses the staff's review criteria for minimum inventory.

Each of these characteristics is discussed in more detail in DCD Tier 2 and is evaluated under Criterion 2 below.

Criterion 2: Development of Actual Items in the Minimum Inventory

Criterion:

The development of actual items in the minimum inventory should include an acceptable set of CDAs developed from the defined scope and criteria of the above Criterion 1. The minimum inventory should appropriately address required operator actions in the emergency procedures or procedure guidelines.

Evaluation:

As noted above, the applicant described five characteristics or criteria for defining the minimum inventory. These five characteristics are evaluated below.

(1) RG 1.97, Types A, B, and C, Category 1 instrumentation

RG 1.97 defines a method for the determination of plant variables to be monitored by control room operators, and for the definition of the appropriate instrumentation to be used for those variables. The criteria of the RG are separated into three categories that provide a graded approach to the requirements depending on the importance of the measurement of a specific variable to safety. Category 1 provides the most stringent requirements and is intended for key variables. Thus, the limitation to Category 1 is appropriate.

Type A variables provide primary information needed to permit the operators to take specified manual actions for which there are no automatic controls, and which are required for safety systems to perform their safety function for design-basis events. Due to the passive nature of the AP1000 and the specific systems design, there are no specific, preplanned, manual actions of this nature. Thus, there are no Type A variables for AP1000.

Type B variables are defined in DCD Tier 2, Section 7.5.3.2, and 18.12.2 and Table 7.5-5. They are variables that provide information to the MCR operators to assess the process of accomplishing or maintaining the six CSFs in the ERGs. DCD Tier 2, Table 7.5-5 lists the Type B variables for AP1000. DCD Tier 2, Table 18.12.2-1, lists the minimum inventory. The six CSF status trees of the ERGs (AF-0.1 through AF-0.6) were reviewed as part of the design certification review to ensure that all Type B variables needed by the operators were included in DCD Tier 2, Tables 7.5-5 and 18.12.2-1. RG 1.97, Table 3, provides a list of PWR Type B variables, which the staff compared to the Type B variables of the AP1000. The staff also compared DCD Tier 2, Table 7.5-5 with Table 18.12.2-1 to ensure that all identified Category 1 Type B variables had been transferred over to the minimum inventory list. With the exception of the items noted below, no discrepancies were identified.

- ERG AF-0.1 contains power range power percent, intermediate range startup rate (SUR), and source range SUR. RG 1.97 calls for monitoring neutron flux from 1E-6 percent to 100 percent. The DCD Tier 2 tables in Chapters 7 and 18 only mentioned neutron flux, but did not address the range or include SUR. The applicant clarified that DCD Tier 2, Table 7.5-1 contains the ranges for all instruments and that only the instrument name is carried forward to the other tables. DCD Tier 2, Table 7.5-1 indicates that neutron flux will be monitored from 1E-6 to 200 percent power. The applicant states that SUR is calculated from the same neutron flux instrument, and modified DCD Tier 2, Table 18.12.2-1 to include startup rate. The staff finds this to be acceptable.

- AF-0.3 contains values for the steam generator (SG) narrow range level, SG pressure, and total feedwater flow that are not in the tables in DCD Tier 2, Sections 7.5 or 18.2. The applicant stated that the analyses indicates that the design-basis cases only require passive residual heat removal (PRHR) as a heat sink and not the SGs. The AP1000 is different from current generation PWRs in that it uses PRHR in place of auxiliary feed water (AFW) and the SGs for the safety-related heat sink. Thus, the SGs and SG parameters are not required variables to indicate whether the heat sink CSF is satisfied. As a result, these variables do not have to be classified as Type B variables or included on the minimum inventory. Thus, the SG parameters for AP1000 are classified as Category D variables. It is noteworthy that the SG parameters are listed in DCD Tier 2, Table 7.5-1 as safety-related parameters and are included in the ITAAC. Hence, they are included on the QDPS. The staff finds this to be acceptable.

Additionally, the SG wide range level, appears to have been classified as a Category 2 variable in the DCD Tier 2, Section 7.5, and not as Category 1, as recommended in RG 1.97. The applicant did not provide adequate justification for this change in classification. The staff also noted that only one channel is required per SG rather than the usual two per SG. The staff also asked if the indication channel is fed from the trip channel. The applicant stated that the AP1000 design has no Category D1 variables, which is consistent with the general statement on page 3 of RG 1.97. DCD Tier 2, Table 7.5-7 also lists no Category D1 variables.

The applicant further stated that the NRC had previously accepted this treatment of SG parameters for the Vogtle and South Texas plants. In the AP1000 design, the SGs are less important than they are at these two plants because the AP1000 uses the PRHR as a safety-related heat sink instead of the AFW system and the SGs. Nonetheless, DCD Tier 2, Section 3.11 qualifies both narrow range and wide range SG levels as PAMS instruments for harsh environments. Also, the indication channel is fed from the same instrument as the trip channel. The applicant is addressing the staff's question concerning the classification of the SG wide range level as a Category 2 variable rather than as Category 1 in its response to issues related to Chapter 7 of this report.

The staff noted several other issues as detailed below:

- AF-0.4 contains a comparison of the RCS cooldown rate and T_C to a limit, based on RCS pressure. The tables in DCD Tier 2, Sections 7.5 and 18.2 do not contain any provision for determining the rate or comparing it to the varying temperature/pressure limit. These parameters can very easily be developed into integrated displays with the computer-based instrumentation system of the AP1000. The applicant added these two parameters to DCD Tier 2, Table 18.12.2-1. The staff finds this to be acceptable.

- AF-0.5 lists the containment radiation level. This variable is not included in DCD Tier 2, Table 7.5-5, but is listed in DCD Tier 2, Table 18.12.2-1. The applicant indicated that it is included in DCD Tier 2, Table 7.5-6 under the RCS boundary, which the staff finds to be acceptable.

- AF-0.6 contains a requirement to monitor pressurizer (PZR) level and PZR level behavior. Both tables contain PZR level, but neither mention the instrumentation related to the time-dependent behavior of the PZR level. The applicant added the PZR level trend to DCD Tier 2, Table 18.12.2-1. The staff finds this to be acceptable.

- RG 1.97 lists the position of the containment isolation valve (CIV). However, the CIV position is limited to remotely operated CIVs. The applicant justified this position by stating that all manual CIVs would be normally locked, under administrative controls, and would have a local vapor phase inhibitor as determined via the OER. The staff finds this to be acceptable.

In summary, the staff finds that DCD Tier 2 satisfactorily covers the Type B variables.

Type C variables are defined in DCD Tier 2, Sections 7.5.3.3 and 18.12.2 and Table 7.5-6. These variables provide the control room operators with information to monitor the potential for breach or actual gross breach of (1) incore fuel cladding, (2) RCS boundary, or (3) containment boundary. DCD Tier 2, Table 7.5-6, lists Type C variables.

DCD Tier 2, Table 18.12.2-1 lists the minimum inventory and includes a column that identifies whether the instrument was based upon a Type B or Type C variable. The staff reviewed the six CSF status trees of the ERGs (AF-0.1 through AF-0.6) to ensure that DCD Tier 2, Tables 7.5-5 and 18.12.2-1 include all Type C variables needed by the operators. RG 1.97, Table 3, provides a list of PWR Type C variables which the staff compared to the Type C variables of the AP1000 design. The staff also compared DCD Tier 2, Table 7.5-6 with Table 18.12.2-1 to ensure that all identified Category 1, Type C variables had been included in the minimum inventory list.

(2) dedicated controls for manual safety-related system actuation (reactor trip, turbine trip, and engineered safety feature actuation)

DCD Tier 2, Section 18.12.2 states that the selection criteria for the AP1000 minimum inventory include dedicated, fixed-position controls to manually initiate system-level actuation signals for the safety-related systems and components that are used to achieve CSFs. DCD Tier 2, Table 18.12.2-1 contains an acceptable identification of dedicated, fixed-position controls to manually initiate system-level actuation signals for the safety-related systems and components that are used to achieve CSFs. The staff finds this to be acceptable.

(3) controls, displays, and alarms required to perform critical manual actions as identified from the PRA analysis

The applicant noted in DCD Tier 2, Section 18.12.2, that the minimum inventory will include fixed-position CDAs to support critical actions. DCD Tier 2, Section 18.8 references WCAP-14651, Revision 2, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," which notes that there are no critical actions. The staff concludes that WCAP-14651, Revision 2, is applicable to the AP1000. The staff evaluations of DCD Tier 2, Section 18.8, and WCAP-14651, Revision 2, discuss the issue of the selection of critical human actions based upon the PRA studies and note that the threshold criteria for selection is high. However, because the applicant also defines risk-important tasks and uses them for other portions of the control room design (i.e., those where critical actions were intended to be used), the staff has accepted the applicant's position.

It should be noted that the staff understands that although the applicant has not identified any critical human actions based on preliminary results from PRA studies completed in 1996, as PRA studies are completed and/or updated, critical human actions may be identified and thus used as input to the minimum inventory. It should also be noted that the applicant's approach to human system design uses input from task analyses (see DCD Tier 2, Figures 18.5-2 and 1-1 WCAP-14651, Revision 2); in addition, critical human actions and risk-important tasks derived from the PRA are used as input to the task analyses.

Therefore, because task analyses are used to verify the minimum inventory (DCD Tier 2, page 18.12-1), both critical human actions and risk-important tasks are used in determining the AP1000 minimum inventory. Thus, the staff believes that the AP1000 minimum inventory addresses all operator actions that were determined to be significant contributors to plant risk by the PRA analyses.

Although the staff has accepted the applicant's criteria for defining critical human actions and risk-important tasks, the high threshold used by the applicant to define critical action selection has eliminated any entries to the minimum inventory that may be judged important based on operating experience and engineering judgment. In particular, the staff considers the manual actuation of ADS a very important action, and notes that it is also classified as a risk-important task by the applicant. Manual actuation of the ADS is based on the level in the core makeup tank (CMT) reaching 67 percent and the ADS not actuating automatically. Consequently, the CMT level is a key parameter needed to judge the necessity for an operator to manually actuate ADS. Thus, the staff believes that CMT level should be included in the minimum inventory list. The applicant subsequently added CMT level to DCD Tier 2, Table 18.12.2-1. The staff finds this to be acceptable.

(4) alarms provided for operator use in performing safety functions to respond to design-basis events for which there are no automatically-actuated safety functions

As noted in the discussion under item (1) above, due to the passive nature of the AP1000 and the specific systems design, there are no preplanned, manual actions required for safety systems to perform their safety function for design-basis events. Thus, because there are no operator actions of the type noted in item (1), there are no alarms required to alert the operators to take this type of action.

(5) controls, displays, and alarms necessary to maintain the CSF and safe-shutdown conditions

The CDAs necessary to maintain the CSFs are the same as those identified in item (1) above, based upon the CSF status trees of the ERGs.

With regard to the CDAs related to maintaining the CSFs and safe-shutdown conditions, the discussions under items (2), (3), and (4) above indicate that the applicant had not included CDAs in the minimum inventory. If one were to go beyond single failure and use the ERG functional restoration guidelines, which are entered from the CSF status trees, then additional controls would be obtained. However, this would add many more dedicated CDAs than appear appropriate in the highly computerized AP1000 control room. If required, this added number of fixed controls may actually be counterproductive to safety because they would create requirements that are not appropriately integrated into the overall HFE of the control room.

The applicant's ERGs also define a CSF associated with shutdown conditions. While the applicant's criterion refers to safe-shutdown, the staff considers this criterion applicable to all shutdown conditions. With regard to the CDAs necessary to maintain shutdown conditions, the staff reviewed the ERG shutdown safety status tree to determine if all required items to implement the tree were on the minimum inventory list.

In addition, the ability to control the normal residual heat removal system (RNS) appears to be essential to maintaining the plant in cold shutdown. The RNS is used to assist in achieving the CSF of core cooling, heat sink, and RCS inventory in cold shutdown conditions. The staff requested the applicant to define the minimum RNS CDAs that should be part of the minimum inventory.

The applicant stated that the RNS is not required for the safety case evaluation of safe-shutdown. For the safety case, the in-containment refueling water storage tank (IRWST), which has both automatic and manual actuation, is used. The minimum inventory includes the manual actuation and related indications. Thus, the RNS CDAs are not necessary to maintain the CSFs or the safe-shutdown conditions. Hence, they are not required to be in the minimum inventory to be consistent with Criterion 5. The staff finds this rationale to be acceptable.

With respect to the alarms detailed on the minimum inventory list, DCD Tier 2, Table 18.12.2-1 includes alarms (alerts) in the minimum inventory and on the QDPS. The staff notes that, when the design is finalized, the alarm acknowledgment scheme should be coordinated between the QDPS and the main alarm system so that the operators are not required to acknowledge the same alarm in two different places.

Based on this information, the staff finds that the applicant has satisfied the minimum inventory criterion.

Criterion 3: Consideration of Operator Tasks

Criterion:

The applicant should identify an inventory of fixed-position CDAs necessary to permit execution of the operator tasks to place and maintain the plant in a safe-shutdown condition.

Evaluation:

DCD Tier 2, Sections 18.12, "Inventory," and 7.4.3, "Safe Shutdown from Outside the Main Control Room," discuss the development of the minimum inventory of CDAs needed to place and maintain the plant in a safe-shutdown condition from either the MCR or the remote shutdown workstation (RSW). The applicant has provided a minimum inventory of fixed-position CDAs for the MCR. The applicant's characteristics for selecting minimum inventory items, which were satisfactorily reviewed under items (1) and (2) above, address operator actions or tasks needed to maintain CSF and safe-shutdown conditions. DCD Tier 2, Section 18.12.3 states that the CDAs of DCD Tier 2, Table 18.12.2-1 are also retrievable from the RSW.

Based on this information, the staff finds that the applicant has satisfied this minimum inventory criterion.

Criterion 4: HFE Input

Criterion:

The inventory contains a list of key minimum CDAs necessary to carry out operator actions associated with the ERGs. The applicant will also need to identify and further define additional detailed characteristics of these CDAs (e.g., ranges, scales, physical dimensions, and actual information presentation) during the detailed task analysis and HSI design efforts. The HFE design process should provide adequate assurance that these detailed characteristics will be defined and implemented.

Evaluation:

The commitments provided in DCD Tier 2, Sections 18.5, 18.8, and 18.11, that address task analysis, HSI design, and the HSI design test program (including V&V) provide an acceptable assurance that these additional detailed characteristics of the CDAs will be defined, designed, tested, and implemented. The staff's detailed review of these sections of DCD Tier 2 are in the staff's evaluation of Sections 18.5, "Task Analysis"; 18.8, Human System Interface Design"; and 18.11, "Human Factors Verification and Validation."

Based on this information, the staff finds that the applicant has satisfied this minimum inventory criterion.

Criterion 5: Task Analysis Input Into Minimum Inventory

Criterion:

The applicant should use the task analysis results to define a minimum inventory of CDAs necessary to perform crew tasks based upon both task and I&C requirements.

Evaluation:

The applicant outlined a method and criteria that will be used to define the minimum inventory. These are delineated in DCD Tier 2, Section 18.12 and have been previously reviewed. The method does not directly use the task analyses, but provides an acceptable alternative based on a combination of RG 1.97, the design features of the AP1000, and the ERGs.

DCD Tier 2, Section 18.5.2.1, "Function-Based Task Analyses (FBTAs)," indicates that the FBTAs are used as a completeness check on the availability of needed indications, parameters, and controls. The DCD Tier 2 also indicates that the OSAs will provide information on the inventory of alarms, controls, and parameters needed to perform sequences selected for analysis including those addressed in Criterion 1, "Scope," discussed in Section 18.5 of this report.

Based on this information, the staff finds that the applicant has satisfied this minimum inventory criterion.

Criterion 6: Development of the Remote Work Station Minimum Inventory

Criterion:

In conjunction with the effort by the applicant to develop a MCR minimum inventory of CDAs for use in the mitigation of transients and accidents, the staff requested that the applicant provide a list of CDAs that would be available at the RSW for use in establishing and maintaining shutdown conditions, in the event the MCR was uninhabitable. The staff does not consider it necessary that any RSW CDAs be fixed-position. However, a minimum inventory of CDAs accessible from the RSW should be well described.

Evaluation:

In DCD Tier 2, Sections 7.4.3.1.1, "Remote Shutdown Workstation," and 18.12.3, "Remote Shutdown Workstation Displays, Alarms, and Controls," the applicant indicated that the same CDAs contained in the MCR workstations will be retrievable from the RSW. This acceptably addresses the staff's questions related to establishing a minimum inventory of CDAs for the RSW.

Based on this information, the staff finds that the applicant has satisfied this minimum inventory criterion.

18.14.4 Conclusions

The applicant defined a minimum inventory of CDAs for the AP1000 design that satisfies the staff's criteria.

18.15 Summary and Conclusions

The overall purpose of the AP1000 HFE review is to ensure the following:

- the applicant has integrated HFE into plant development and design
- the applicant has provided HSIs that make possible safe, efficient, and reliable performance of operation, maintenance, test, inspection, and surveillance tasks
- the HSI reflects "state-of-the-art human factors principles" (see 10 CFR 50.34(f)(2)(iii), as required by 10 CFR 52.47(a)(1)(ii)) and satisfies all specific regulatory requirements as stated in Title 10 of the Code of Federal Regulations

In addition, the staff's review included the applicant's proposed resolutions of unresolved safety issues, generic safety issues, and related human factors considerations addressed in Chapters 6, 7, 9, 13, 14, 16, 19, and 20 of DCD Tier 2.

In conclusion, for the reasons set forth in this section, the applicant's HFE DCD, as well as the other supporting materials reviewed describes a comprehensive HFE Program that complies with applicable regulatory requires and is consistent with the staff's review criteria.

18.16 Tier 2* Information:

As a result of its review of the AP 1000 HFE Program, the staff has determined that the following information in DCD Tier 2, Chapter 18 must be designated as Tier 2* information in the AP1000 DCD. This information is similar to Tier 2* HFE information for the evolutionary plants and, as with the evolutionary design certifications, the Tier 2* information identified herein is not subject to expire at first full power. Furthermore, any proposed change to Tier 2* information, by a COL applicant or licensee, will require NRC approval prior to implementation. The affected sections in DCD Tier 2 are provided below; the rationale for selecting this information is provided in parentheses.

18.2.1.2	Regulatory Requirements (assures HFE Program meets design requirements)
18.2.1.3	Applicable Facilities (assures scope of HFE Program)
18.2.1.4	Applicable Human System Interfaces (assures scope of HFE Program)
18.2.1.5	Applicable Plant Personnel (assures scope of HFE Program)
18.2.1.6	Technical Basis (assures that HFE Program will be developed in accordance with specified standards, guidelines, and accepted professional practices)
18.2.2.1	Responsibility (assures preservation of HFE Program Design Team integrity)
18.2.2.3	Composition *[first paragraph and listing of design team disciplines only]* (assures preservation of design team multidisciplinary composition)
18.2.3.1	General Process and Procedures [last paragraph of Design Review of Human Factors Engineering Products only] (assures preservation of commitment to design issues tracking system implementation)
18.2.3.5	Human Factors Engineering in Subcontractor Efforts (assures that subcontractors employ accepted human engineering practices)
18.2.4	Human Factors Engineering Issues Tracking (assures preservation of commitment to use of design issues tracking system database implementation)
18.2.5	Human Factors Engineering Technical Program and Milestones (assures that the HFE Program is performed in accordance with NUREG-0711)
Figure 18.2-1	Human Factors Engineering Program Management, Human System Interface (HSI) Design Team Process (assures preservation of commitment to conduct HFE process)
18.5	AP1000 Task Analysis Implementation Plan (assures task analysis objectives are met)
18.5.1	Task Analysis Scope (assures preservation of commitment to task analysis scope and process, implementation of which will be verified by the ITAAC)
18.5.2	Task Analysis Implementation Plan (assures preservation of commitment to scope and methodology for task analysis plan, implementation of which will be verified by the ITAAC)

18.5.2.1	Function-Based Task Analysis (assures that the set of questions provided for function-based task analysis is used)
18.7	Integration of Human Reliability Analysis with Human Factors Engineering (assures preservation of commitment to details of HRA integration, implementation of which will be verified by the ITAAC)
18.8	Human System Interface Design (assures that the alarm system supports the crew in accordance with the decisionmaking model and that computerized procedures/backup will be confirmed through the V&V program)
18.8.1.2	Design Guidelines (assures the use of specific guidelines for performing V&V)
18.8.1.7	Task-Related Human System Interface Requirements (assures that the HSI design provides needed alarms, displays, and controls)
18.8.1.8	General Human System Interface Design Feature Selection (assures that a decisionmaking model is used to identify operator information and control requirements)
18.8.1.9	Human System Interface Characteristics [Identification of High Workload Situations] (assures that critical and risk-important human actions related to local control actions are identified)
18.8.2	Safety Parameter Display System (SPDS) [includes all sections through 18.8.2.7] (assures function of SPDS will be incorporated as part of overall HSI program, implementation of which will be verified by the ITAAC)
18.8.3.2	Main Control Area Mission and Major Tasks (assures preservation of commitment to MCR mission, conduct of operation, and major components of MCR covered by HFE Program)
18.8.3.4	Remote Shutdown Workstation Mission and Major Tasks Implemented (assures preservation of commitment to RSW mission, conduct of operation, and major components of RSW covered by HFE Program)
18.8.3.5	Technical Support Center Mission and Major Tasks (assures preservation of commitment to TSC mission, conduct of operation, and major components of TSC covered by HFE Program)
18.11	Human Factors Engineering Verification and Validation (assures preservation of commitment to scope and conduct of HSI engineering tests, implementation of which will be verified by the ITAAC)

18.12 Inventory [Sections 18.12.1 through 18.12.3, Remote Shutdown Workstation Displays, Alarms, and Controls] (assures preservation of commitment to scope and development of minimum inventory for future iterations of the AP1000 PRA)

In addition to the above DCD sections, the following DCD Tier 2, supporting documents are also designated as Tier 2* information:

WCAP-14396 Revision 3, "Man-in-the-Loop Test Plan Description" (principal design document supporting 18.11)

WCAP-14651 Revision 2, "Integration of Human Reliability Analysis With Human Factors Engineering Design Implementation Plan" (principal design document supporting 18.7)

WCAP-14695 "Description of the Westinghouse Operator Decision-Making Model and Function-Based Task Analysis Methodology" (principal design document supporting 18.5.1)

WCAP-15847 Revision 1, "AP1000 Quality Assurance Procedures Supporting NRC Review of AP1000 DCD Sections 18.2 and 18.8" (principal design document supporting Sections 18.2 and 18.8)

WCAP-15860 Revision 2, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan" (principal design document supporting 18.11)