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NTD-NRC-94-4254
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Docket No.: STN-52-003

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U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

ATTENTION: R. W. BORCHARDT

SUBJECT: WESTINGHOUSE RESPONSES TO NRC REQUESTS FOR ADDITIONAL INFORMATION ON THE AP600

Dear Mr. Borchardt:

Enclosed are three copies of the Westinghouse responses to NRC requests for additional information on the AP600 from your letters of April 19, 1994, April 29, 1994, May 2, 1994, May 5, 1994, May 12, 1994, May 16, 1994, May 23, 1994, May 26, 1994, June 8, 1994 and June 27, 1994. In addition, revisions of responses previously submitted are provided.

A listing of the NRC requests for additional information responded to in this letter is contained in Attachment A.

These responses are also provided as electronic files in WordPerfect 5.1 format with Mr. Kenyon's copy.

If you have any questions on this material, please contact Mr. Brian A. McIntyre at 412-374-4334.

Nicholas J. Liparulo, Manager
Nuclear Safety Regulatory And Licensing Activities

/nja

Enclosure

cc: B. A. McIntyre - Westinghouse
T. Kenyon - NRR

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NTD-NRC-94-4254
ATTACHMENT A
AP600 RAI RESPONSES
SUBMITTED AUGUST 3, 1994

210.81	410.180	440.185
210.111	410.183	440.186
220.93	410.197	440.187
260.27R1	410.198	440.188
280.6	435.78	440.193
410.113	435.79	440.200
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410.135	440.60	440.213
410.137	440.73	440.223
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410.147	440.80	460.4R1
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410.178	440.177	720.277
410.179	440.183	920.3

Question 210.81

Revision 1 to WCAP 13054 lists an exception to Section 1 of Section 3.10 of the SRP, that states that safety-related equipment may be qualified, in part, based on properly documented experience data in accordance with Section 9.0 of IEEE 344-1987. As used in IEEE 344, experience data includes both seismic experience and previous qualifications. The staff has not accepted the use of seismic experience on either evolutionary or passive plants. In accordance with Revision 2 to RG 1.100, this method of qualification will be reviewed by the staff on a case-by-case basis. Revise the above exception and any other applicable SSAR section to reflect this staff position. In addition, include a statement in the SSAR that if dynamic qualification of seismic Category I electrical or mechanical equipment is accomplished by experience, the COL applicant should provide the following for NRC review and approval:

a. Identification of the specific equipment.

b. The details of the methodology and the corresponding experience data for each piece of equipment.

Response:

IEEE-344-1987 is an extension and clarification of the IEEE-344-1975. Both documents provide the same rules and requirements for the seismic qualification of Class 1E equipment. The seismic qualification of Class 1E safety-related equipment based on properly documented experience data is performed in accordance with Section 9.0 of IEEE 344-1987 on case-by-case basis. In such cases where experience data is used, all aspects of the qualification basis and supporting data are properly documented. Identification of the specific equipment qualified based on experience and the details of the methodology and the corresponding experience data for each piece of equipment will be included in the equipment qualification file. See the response to RAI 210.86 for additional information on the maintenance of the equipment qualification file.

SSAR Revision:

Add the following paragraph to Subsection 3.10.2.

The seismic qualification of Class 1E safety-related equipment and active valves and dampers may be based on properly documented experience data. Seismic qualification based on experience is performed in accordance with Section 9.0 of IEEE 344-1987 on case-by-case basis. In such cases where experience data is used, all aspects of the methodology, qualification basis, and supporting data are properly documented by the Combined License applicant. Identification of the specific equipment qualified based on experience and the details of the methodology and the corresponding experience data for each piece of equipment is included in the equipment qualification file.

Question 210.111

SSAR Section 5.4.2.1 states that although the secondary side of the steam generator is ASME Class 2, all pressure-retaining parts of the secondary side are designed to ASME Class 1 rules.

a. Identify the secondary side parts that are applicable to this statement. If the feedwater ring is not included in this category, provide the design bases for this part.

b. In Section 5.4.2.1 of the SSAR, identify all safety-related non-pressure-retaining parts of the steam generator assembly and provide the design bases for these parts if they are not constructed to ASME Section III, Subsection NC.

Response:

a. The following secondary side steam generator parts are ASME Code, Section III, Class 2 parts, but are designed to ASME Class 1 rules.

   Secondary Side Shell
   Secondary Side Manways, Handholes, and Inspection Ports
   Blowdown, Drain, Wet Layup, and Sampling Nozzles
   Wide Range, Narrow Range, and Level Sensor Instrumentation Taps
   Trunion Attachments
   Steam Outlet Nozzle
   Feedwater Inlet Nozzle

   The feedwater water ring is classified as ASME Code, Section III, Class 2. The design basis used is ASME Code Section III, Subsection NG.

b. The following table identifies all safety-related non-pressure-retaining parts of the steam generator and identifies the design basis for the parts that are not constructed to ASME Section III, Subsection NC. Since the steam generator internals are not pressure-retaining parts, the safety-related internal parts are designed to the rules found in ASME Code Section III, Subsection NG.

Safety-Related Non-Pressure-Retaining Parts	Safety Classification (AP600 Class)	Design Basis
Primary Channel Head Divider Plate	Safety-Class 2 (AP600 Class B)	ASME Section III, Subsection NB
Flow Limiting Venturi	Safety-Class 2 (AP600 Class B)	ASME Section III, Subsection NG

Safety-Related Non-Pressure-Retaining Parts	Safety Classification (AP600 Class)	Design Basis
Feedwater Distribution Ring Assembly & Supports	Safety-Class 2 (AP600 Class B)	ASME Section III, Subsection NG
Tube Bundle Support Assembly	Safety-Class 3 (AP600 Class C)	ASME Section III, Subsection NG
Nozzle Dam Bracket	Safety-Class 3 (AP600 Class C)	ASME Section III, Subsection NG
All Other Assemblies	Non-Nuclear Safety (AP600 Class D or E)	NA

SSAR Revision:

Table 3.2-3 (Sheet 33 of 107)
ASME Classification of Components and Systems

Component Description	Loc	AP600 Class	Seismic Category	Principal Construction Code	Comments
Reactor Coolant System					
RCS MB 01 STEAM GENERATOR 1	11	A	I	ASME III-1	
SHELL SIDE	11	B	I	ASME III-1	
CHANNEL HEAD	11	B	I	ASME III-1	
DIVIDER PLATE					
TUBE BUNDLE SUPPORT ASSEMBLY	11	C	I	ASME III, NG	
FLOW LIMITING VENTURI	11	B	I	ASME III, NG	
FEEDWATER DISTRIBUTION RING ASSEMBLY SUPPORTS	11	B	I	ASME III, NG	
NOZZLE DAM BRACKET	11	C	I	ASME III, NG	
RCS MB 02 STEAM GENERATOR 2	11	A	I	ASME III-1	
SHELL SIDE	11	B	I	ASME III-1	
CHANNEL HEAD	11	B	I	ASME III-1	
DIVIDER PLATE					
TUBE BUNDLE SUPPORT ASSEMBLY	11	C	I	ASME III, NG	
FLOW LIMITING VENTURI	11	B	I	ASME III, NG	
FEEDWATER DISTRIBUTION RING ASSEMBLY SUPPORTS	11	B	I	ASME III, NG	
NOZZLE DAM BRACKET	11	C	I	ASME III, NG	

Question 220.93

Under severe accident loading, thermal expansion of the containment shell is restrained at the transition region. The restraint of thermal expansion produces a compressive hoop stress in the containment vessel in the vicinity of the discontinuity. Thus, the effect of severe accident temperature loading needs to be evaluated to assure that the expected compressive hoop stresses resulting from the load at the transition region (along the entire periphery of the shell) do not lead to buckling of the containment shell causing a loss of containment function. Provide the results of the buckling analysis of the containment shell under the severe accident temperature loading in the SSAR.

Response:

The effect of temperature loading at the base of the containment vessel is being evaluated. The results of this evaluation will be provided by December 1994.

SSAR Revision: NONE

Question 260.27

Revise Section 14.2.7, "Test Program Schedule," of the SSAR to identify the following as a COL Action Item: A COL applicant will need to provide a startup administrative manual (procedures), and any other documents that delineate the test program schedule, for staff review (see Q260.25).

Response:

Section 14.2.7 will be revised to identify that the COL applicant is responsible for a startup administrative manual (procedures), and other documents that delineate the test program schedule.

SSAR Revision:

14.2.7 Test Program Schedule

The startup administrative manual (procedures), and other documents that delineate the test program schedule for the initial fuel load and for each major phase of the initial test program will be ~~provided by the owner/operator~~ the responsibility of the COL applicant.

This schedule will include the timetable for generation, review, and approval of procedures as well as the actual testing and analysis of results.

Although there is considerable flexibility available in the sequencing of testing within a given phase, there is also a basic order that will result in the most efficient schedule.

During the preoperational phase, testing will be performed as system turnover from construction allows. However, the interdependence of systems will also be considered so that common support systems (such as electrical power distribution, service and instrument air, and the various makeup water and cooling systems) are tested as early as possible.

Sequencing of tests during the startup phase will depend primarily on specified power and flow conditions and intersystem prerequisites.

The schedule will establish that, prior to core load, the test requirements will be met for those plant structures, systems, and components that are relied upon to prevent, limit, or mitigate the consequences of postulated accidents.

Additionally, testing will be sequenced so that the safety of the plant is not dependant on untested systems, components, or features.

The detailed testing schedule will be generated and maintained at the job site so that it may be regularly updated to reflect actual progress and the current test plan.

Add the following line to Table 1.8-1

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
14.3	Test Program Schedule	AP600 Interface	Combined License applicant Program	14.2.7

Question 280.6

Indicate the location of the eight hour battery packs (safety- and non-safety-related).

Response:

The eight-hour battery pack sealed beam lighting units are nonsafety-related and powered from the nonsafety-related, diesel-backed buses. These lighting units are located in areas where emergency building operations to achieve safe shutdown are not performed. Also, refer to the responses to RAIs 435.69 and 435. 72R1.

The eight-hour battery pack units are located in access/egress routes designated for emergency building evacuation, and in areas where manual actions may be required during a fire or for recovery of ac power to normal lighting. The following areas are applicable to this category.

- Standby diesel generator rooms
- Switchgear rooms (annex and turbine buildings)
- Fire pump rooms
- Connecting corridors and stairwells
- Access routes from the main control room to and from the remote shutdown area
- Access and egress routes as determined by the fire analysis

SSAR Revision: NONE

Question 410.113

Describe how the SWS component allowable operational degradation is determined. Describe the procedures that will be followed to detect the degraded conditions when they become excessive.

Response:

The service water system (SWS) incorporates features that facilitate inspection and/or testing of SWS components that may degrade over time due to wear, erosion, corrosion or fouling. These include the following:

- Piping is accessible for inspection and/or wall thickness determination. SWS piping that runs in the yard area is either routed within trenches or may be inspected from the inside.
- Pressure and flow instrumentation and/or provisions for temporary instrumentation are provided to test SWS pump performance. Permanent instrumentation is provided for on-line monitoring of system flow and pressure.
- Temperature and flow instrumentation or provisions for temporary instrumentation are provided to test SWS heat exchangers for thermal performance and flow rate.
- The component cooling system (CCS) plate heat exchangers can be disassembled in place for complete inspection or cleaning.
- The SWS cooling tower is designed to allow inspection and/or testing of key components. Access features are provided for inspecting the tower fill material. The tower and basin are divided into two sections such that one section of tower components can be out of service for inspection while the other section remains in service. Similarly, half of the basin can be drained at a time for inspection and cleaning.

The SWS is a nonsafety-related Class D system and is considered to be available in the probabilistic risk assessment. As discussed in SSAR Subsection 3.2.2.6, the reliability and maintenance plans for such systems include provisions to check for operability.

SSAR Revision: NONE

Question 410.114

Demonstrate that the SWS pumps have sufficient available net positive suction head (NPSH) at the pump suction locations considering low water levels. How much margin is there for the NPSH? Provide sufficient information for the staff to verify your conclusion.

Response:

This system performs no safety-related functions. Calculations are available from the design organization which verify that NPSH requirements are met.

In summary, design requirements for the service water system (SWS) specify that the minimum NPSH available at the SWS pumps exceed the required NPSH by either 25% or 10 feet, whichever is less. This margin is applied for conditions of maximum basin temperature, normal operating flow, and normal basin water level. The SWS pumps have a maximum required NPSH of 27 feet at normal operating flow. The design of the SWS also ensures that minimum NPSH available exceeds the required NPSH for conditions of low water level. During operation the minimum water level in the service water cooling tower basin is at least 5 feet above the SWS pump suction inlet. With these conditions, the required NPSH for the pumps is satisfied.

SSAR Revision: NONE

Question 410.135

Provide a diagram of the steam and power conversion system in the non-proprietary portion of the SSAR, including a heat balance, in accordance with the guidance in RG 1.70.

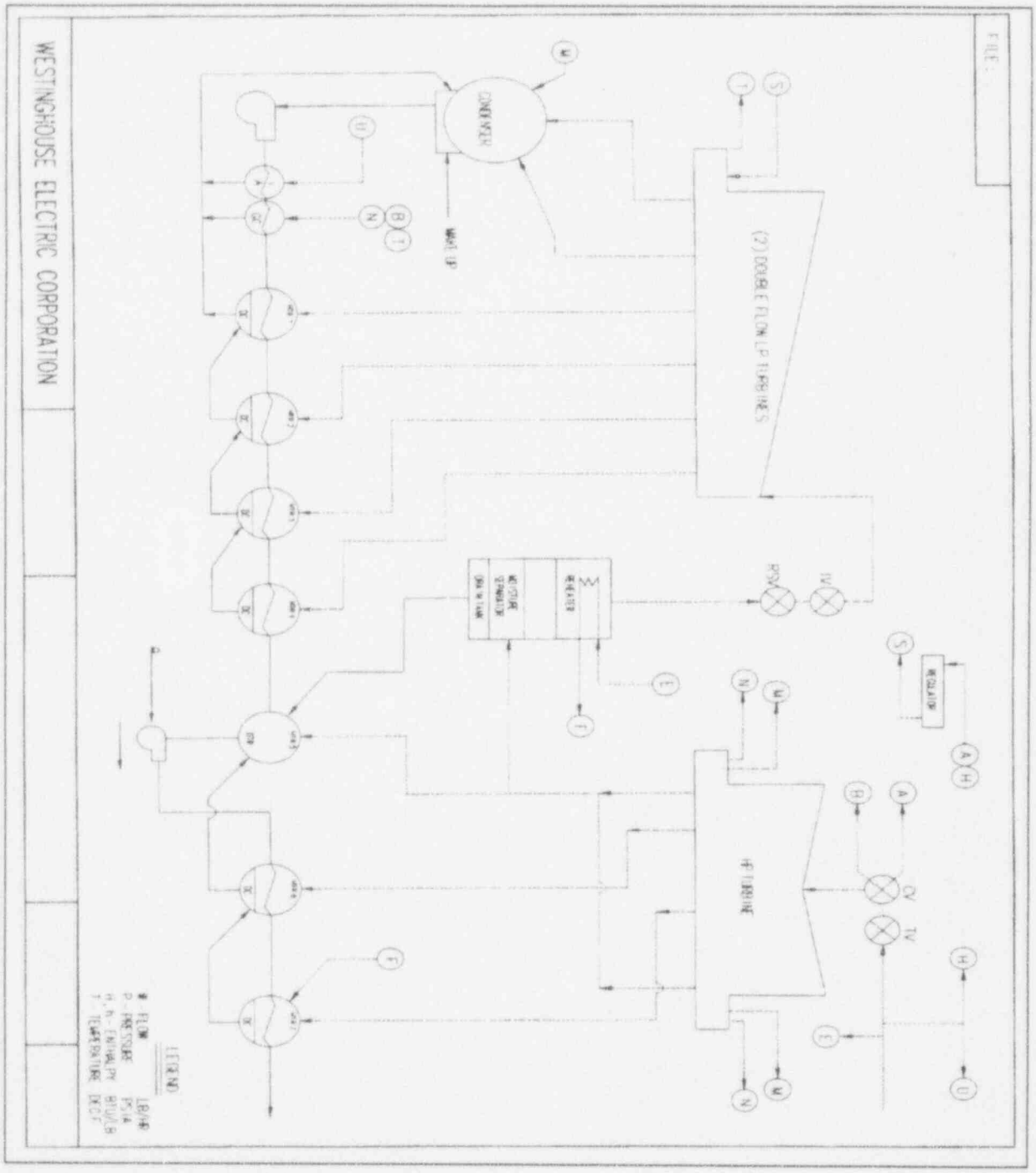
Response:

A heat balance showing system configuration will be provided as Figure 10.1-2.

SSAR Revision:

Figure 10.1-2 will be added to the SSAR

AP600



Westinghouse

Question 410.137

Section 10.2.1.2 of the SSAR states that the turbine-generator is intended for baseload operation and also has load follow capability consistent with the capabilities of the Westinghouse NSSS. Clarify the term "load follow capability consistent with the capabilities of the Westinghouse NSSS." Is it a defined load? Where is it defined? Is it the load that is consistent with the load demand from the reactor power control system? Is it specifically for the AP600 reactor, or is it subject to Westinghouse NSSS future design changes? Does it include the performance requirements of upset, emergency, and faulted conditions in accordance with RG 1.70?

Response:

The design load follow pattern is described in SSAR Subsection 7.7.1.1. SSAR Subsection 7.7.2 provides information on the plant control system and its response under stated reference transients. The transients specified in this section are also applicable to the turbine.

- The AP600 turbine-generator consists of standard components that have been optimized for power production consistent with the AP600 reactor.
- SSAR Subsection 3.9.1 provides information on the performance requirements (upset, emergency, and faulted conditions) of the AP600 as required in RG 1.70.

SSAR Revision: NONE

Question 410.140

Section 10.2.2 of the SSAR states that the turbine-generator consists of turbines, a generator, external moisture separator reheaters, an exciter, controls, and auxiliary subsystems as shown in Figure 10.2-1. The described components should be in a non-proprietary figure. The function of the exciter is not discussed anywhere in the SSAR. Describe the functions of the exciter in the SSAR.

Response:

The components will be indicated on Figure 10.2-2 (Turbine Building Elevation 165 General Arrangement) in the non-proprietary section of the SSAR.

Excitation System Description

The excitation system is a brushless exciter with a solid state voltage regulator. The exciter is designed so that high power components are mounted on the rotating shaft. The performance of the brushless excitation system is not affected by reduced system voltage during system disturbances since the excitation power is obtained from the rotating shaft which is directly connected to the main generator shaft.

The brushless exciter is housed in a self-ventilated enclosure and consists of three basic parts: a permanent magnet pilot exciter, a main ac exciter, and a rectifier wheel.

The field of the permanent magnet generator (PMG) is utilized for the primary excitation. The permanent magnet generator field of the pilot exciter induces a voltage in the stationary pilot exciter armature windings. With the armature stationary, the need for brushes and current collection devices is eliminated. This permits feeding the relatively high frequency, three phase output of the pilot exciter stator (armature) where it is rectified and controlled in magnitude. The dc output is then fed to the stationary ac exciter field winding where it induces a voltage in the rotating ac exciter armature winding. The output of the main ac exciter is rectified by rotating diodes on the rotor shaft, producing a dc voltage. The main excitation power is then fed directly to the field coils in the generator rotor.

A generator field ground detector monitors the insulation resistance of the exciter armature and generator field winding. Should a ground develop, indicated by low insulation resistance, an alarm will occur. Air-to-water heat exchangers mounted in the upper portion of the exciter enclosure provide cool air in a recirculating system. A fan on the end of the shaft provides circulation of the air.

The exciter uses rectifiers arranged in a full wave bridge configuration. The rectifier components are mounted on the inside diameter of a steel retaining wheel. Each rectifier is protected by a wheel-mounted, series-connected fuse having a color-coded indicating device that may be inspected during operation by using a stroboscope.

A non-proprietary drawing of the T/G, MSR, Exciter, Controls, and auxiliary subsystems is added to the SSAR as Figure 10.2-2.

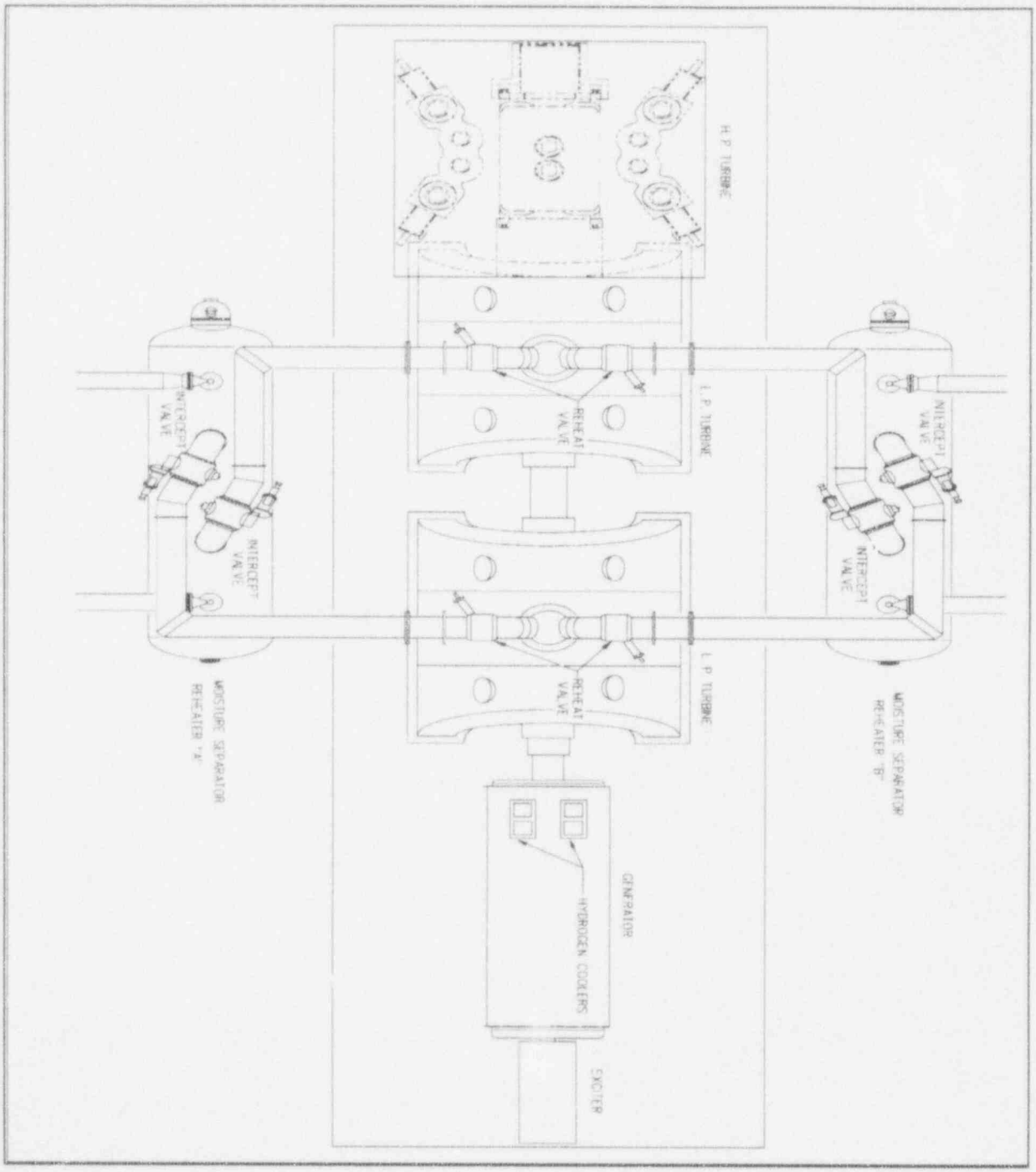
SSAR Revision: Revise Subsections 10.2.2 and 10.2.2.3 as follows:

10.2.2 System Description

The Westinghouse turbine-generator is designated as a TC4F 47-inch last-stage blade unit consisting of turbines, a generator, external moisture separator reheaters, exciter, controls, and auxiliary subsystems. (See Figure 10.2-1.) Figure 10.2-2 is a nonproprietary equipment outline drawing illustrating the same systems. The major design parameters of the turbine-generator and auxiliaries are presented in Table 10.2-1. The piping and instrumentation diagram containing the stop, governing control, intercept, and reheat valves is shown in Figure 10.3.2-2.

10.2.2.3 Exciter Description

The excitation system is a brushless exciter with a solid state voltage regulator. Excitation power is obtained from the rotating shaft which is directly connected to the main generator shaft. The brushless exciter consists of three parts: a permanent magnet pilot exciter, a main AC exciter, and a rectifier wheel. The exciter rectifiers are arranged in a full wave bridge configuration and protected by a series connected fuse. The turbine building closed cooling water system (TCS) provides cooling water to the exciter's air to water heat exchangers.


MOISTURE SEPARATOR
REHEATER "B"
INTERCEPT
VALVE
INTERCEPT
VALVE
L.P. TURBINE
REHEAT
VALVE
H.P. TURBINE
REHEAT
VALVE
L.P. TURBINE
INTERCEPT
VALVE
INTERCEPT
VALVE
MOISTURE SEPARATOR
REHEATER "A"
GENERATOR
HYDROGEN COOLERS
EXCITER

Question 410.147

Section 10.3 of the SRP, "Main Steam Supply System," states that the system design should adequately consider steam hammer to assure that system safety functions can be achieved and that operating and maintenance procedures include adequate precautions to avoid steam hammer and relief valve discharge loads. Address the design considerations to prevent adverse effects of steam hammer in the SSAR.

The SSAR does not address any activity or program regarding personnel awareness of potential occurrence of steam hammer dynamics. The SSAR should include a statement that such a program should be developed and implemented by the COL applicant. Provide guidance for developing plant operating and maintenance procedures that will protect against a potential occurrence of steam hammer.

Response:

The following aspects of the AP600 design address the concern in SRP Section 10.3 regarding steam hammer.

1. The stress analyses for the safety-related portion of the main steam system piping and components include the dynamic loads from rapid valve actuations, including actuation of the main steam isolation valves and the safety valves. This is stated in the third paragraph of SSAR Subsection 10.3.2.2.1.

2. Design features that prevent water slug formations are included in the system design and layout. In the main steam system, these include the use of drain pots and the proper sloping of lines.

3. The operating and maintenance procedures that protect against a potential occurrence of steam hammer include system operating procedures that provide for slowly heating up (to avoid condensate formation from hotter steam on colder surfaces), operating procedures that caution against fast closing of the main steam isolation valves except when necessary, and operating and maintenance procedures that emphasize proper draining.

SSAR Revision:

Regarding item 2. above, see the SSAR revision in response to RAI 410.253.

Regarding item 3. above, SSAR Subsection 10.3.2.3.1 will be revised as follows:

10.3.2.3.1 Normal Operation

During normal power operation, the main steam supply system supplies steam to meet the demand of the main turbine system. The main steam supply system also supplies steam as required to the auxiliary steam system, and reheating steam to the moisture separator reheaters. At low plant operating loads, the main steam supply system provides steam to the turbine steam sealing system.

The main steam supply system is capable of accepting a ±10-percent step change in load followed by a ±5-percent/min ramp change without discharging steam to the atmosphere through the main steam safety valves or to the main condenser through the turbine bypass system. For large step change load reductions, steam is bypassed (up to 40 percent of full load flow) directly to the condenser via the turbine bypass system. As discussed in Subsection 10.4.4, the main steam supply system in conjunction with the turbine bypass system is capable of accepting a 100-percent net load rejection without reactor trip (in conjunction with a reactor rapid power reduction) without lifting safety valves. If the turbine bypass system is not available, steam is vented to the atmosphere via the power-operated atmospheric relief valves and the main steam safety valves, as required.

Steam hammer prevention is addressed by appropriate precautions in the operating and maintenance procedures. The operating and maintenance procedures that protect against a potential occurrence of steam hammer include system operating procedures that provide for slowly heating up (to limit condensate formation on colder surfaces), operating procedures that caution against using the main steam isolation valves except when necessary, and operating and maintenance procedures that emphasize proper draining.

Question 410.154

Revise Section 9.3.1 of the SSAR to address the following:

a. Provide a list of the building(s) in which the major components of the compressed and instrument air systems are located.

b. Provide the minimum particle size that the compressor intake filter is designed to remove.

c. State whether each individual air compressor is designed for 100% capacity.

d. Provide a more detailed list of the instrumentation and controls that are provided in the main control room.

e. Provide information about (1) sample lines and valves for obtaining air samples and (2) a periodic air quality sampling program.

f. Provide information regarding the air quality of the breathing air subsystem. Does the air quality meet ANSI/CGA G-7.1 requirements?

g. State how the compressed and instrument air system complies with Generic Issue 43 (Including Generic Letter 88-14 and NUREG-1275).

Response:

a. The major components of the compressed and instrument air system (CAS) are located in the turbine building. These components include compressors, receivers, and air dryers/purifiers.

b. The compressor intake filter is a portion of the compressor package and is provided by the vendor. The filters on the instrument air, service air, and breathing air subsystems remove particulates 10 microns and larger from the entering air supply to the compressors.

c. The service air and breathing air subsystems each have one compressor that is sized to provide 100 percent of the anticipated demand. The instrument air subsystem consists of two compressors of identical size. Each is nominally rated to provide 100 percent of the required instrument air flow.

d. The control, pressure, and temperature instrumentation provided as a part of the compressor package, air dryer package, and breathing air purifiers will be available in the main control room via the plant control system. The system parameters listed below are available in the main control room.

Instrument Air

Compressor discharge pressure
Air receiver temperature and pressure
Air header pressure
Air header moisture indication

Service Air

Air receiver temperature and pressure
Service air header pressure inside containment
Moisture indication

Breathing Air

Header pressure
Emergency air backup supply header pressure

e. Sample points are provided downstream of the air dryers in the instrument air subsystem and downstream of the purifiers in the breathing air subsystem. Each sample line includes a manual valve.

The samples will be obtained on a periodic basis and analyzed for air quality/purity using appropriate analysis equipment.

f. The breathing air subsystem is designed to provide Quality Verification Level D as required by 29 CFR, Chapter XVII, OSHA. The breathing air subsystem meets the air quality standards specified in ANSI/CGA G-7.1.

g. Generic Issue 43, Generic Letter 88-14, and NUREG-1275 deal with adverse effects on safety-related equipment caused by instrument air system failures. Compressed air system failures do not prevent safety-related equipment from performing their safety-related functions. The AP600 design provides for two 100 percent instrument air compressors in a lead/lag control scheme. The second air compressor is automatically started if system pressure drops below a predetermined value. Additionally, the air receivers provide approximately ten minutes of normal instrument air supply in the event of loss of power to both compressors. This ten minute interval is utilized to sequence the air compressor to a diesel generator and restart the compressor from an alternate power supply.

Safety-related, pneumatically-operated valves that are required to change valve position to achieve safe shutdown and accident mitigation are driven to their fail-safe position by safety-related backup accumulators or are mechanically spring actuated on loss of instrument air as indicated in SSAR Subsection 9.3.1.3.

SSAR Revision: See revised sections of the SSAR attached to and referenced in RAI 410.152.

Question 410.166

How is backflooding prevented in the radioactive waste drain system (Section 9.3.5) and in the liquid radwaste system (Section 11.2)?

Response:

Containment compartment drains to the containment sump each have two check valves in series to prevent back flooding from the containment sump back into the compartments. See SSAR section 3.4.1 and response to RAI 410.1 for additional details on the backflow preventers for the containment sump.

Outside of containment, the liquid radwaste system receives water from many sources to the effluent holdup tanks, waste holdup tanks and chemical waste tank. Holdup tanks are vented to atmosphere with independent overflow connections. Backflooding from these tanks is not possible.

SSAR Revision: None

Question 410.168

Is the third paragraph in Section 9.3.5.1.1 of the SSAR meant to indicate that safety-related systems, structures, or components are not damaged as a result of equipment and floor drain components failure from a seismic event? Clarify the paragraph.

Response:

The safety functions of seismic Category I structures, systems, and components are protected from interaction with the non-safety related portion of the equipment and floor drain system components or their interaction is evaluated for an SSE. The non-safety related portion of the equipment and floor drain system components is designed such that an SSE does not adversely impact the safety related structures, systems, and components. SSAR subsection 3.7.3.13 discusses the methods used to evaluate such interactions.

SSAR Revision: NONE
PRA Revision: NONE

Question 410.174

Address the following questions concerning Section 9.5.4 of the SSAR "Onsite Standby Diesel Generator Fuel Oil Storage and Transfer System:"

a. Why is cathodic protection, in accordance with NACE Standard RP-01-69, not provided for all external surfaces of buried metallic piping and tanks?

b. Why is the fuel oil system designed without an overflow line on the day tanks?

c. How is the fuel oil in the fuel oil storage tanks and day tanks in Section 9.5.4 of the SSAR maintained above the cloud point? What is the minimum expected outdoor temperature?

d. Is the day tank physically located at an elevation that assures a slight positive pressure at the suction of the engine-driven fuel oil pump?

e. Are the two above-ground fuel oil storage tanks protected from excessive heat that can contribute to the degradation of the fuel oil? Are they sheltered or painted with reflective paint?

Response:

a. The fuel oil piping is carbon steel and is contained within a containment pipe to comply with EPA requirements. If the final design requires the use of steel containment piping to accommodate overburden loads, the containment pipe will be provided with cathodic protection. Alternately FRP or PVC (plastic) containment piping may be used which will not require cathodic protection.

   The fuel oil storage tank is mounted on a concrete pedestal within a containment diked system and does not come into contact with the ground, therefore the tank does not require cathodic protection.

b. The AP600 design utilizes above grade fuel oil storage and day tanks which preclude the possibility of a gravity overflow system from the day tank to the fuel oil storage tank, since the level of stored fuel in fuel oil storage tank is approximately 20 feet higher than the day tank overflow level. Therefore, the day tank does not have a gravity overflow connection or discharge. The day tank level controls will maintain the tank levels within the required range. To protect the day tank in the event of accidental overfilling, its design pressure is sufficient to withstand the system maximum static head. Provisions for overflow of the day tank have been included. The overflow line from the day tank discharges back to the fuel oil storage tank through the recirculation line. The day tank vent will terminate above the diesel building roof at a higher elevation than the storage tank fuel level to prevent fuel spills.

c. The fuel oil in the fuel oil storage tank is heated by the in-line electric heater and recirculated to maintain a fuel oil pipe line temperature above the cloud point temperature. The day tanks are in an enclosed building environment where the temperature of the diesel fuel oil is maintained above the cloud point temperature. The design outdoor temperature for nonsafety-related systems at a 1% exceedance is a minimum of minus (-10°F).

d. The day tank elevation is established so that at normal high fuel level there will be a slight positive pressure on the engine driven fuel pump for the initial start. During operation, the day tank level may be lower than the fuel pump until the day tank is refilled to the normal high level setpoint.

e. It is not planned to enclose the fuel oil storage tanks or to provide sun shelters for shade. Provisions will be made in the plant installation specifications to finish paint the tanks with a reflective paint system.

SSAR Revision: Table 9.5.4-1 (Sheet 3 of 3) will be revised as follows:

Table 9.5.4-1 (Sheet 3 of 3)

Component Data
Standby Diesel and Auxiliary Boiler Fuel Oil System

Flame Arresters (Storage and Day Tanks) . . . . . Manufacturer's standards

Diesel Fuel Oil Day Tanks

Quantity	2
Type	Horizontal, cylindrical
Capacity (gal)	1500
Available capacity (gal)	1200
Operating pressure	Atmospheric
Operating temperature	Ambient
Design pressure (psig)	~~Atmos.~~10
Design temperature (°F)	200
Material	Carbon steel
Code	NFPA-Std-142
Seismic design	U.B.C.

Question 410.177

Section 9.5.4.2.3 of the SSAR states that the fuel oil storage tank fill line is approximately 4 feet above grade. Is this higher than the PMF flood level?

Response:

The plant finished grade elevation will be higher than the PMF flood level per SSAR Subsection 3.4.1.1.1 - "Protection from External Flooding". Therefore the fuel oil storage tank fill connection at four feet above grade located at the truck unloading station will not be exposed to floods.

SSAR Revision: NONE

Question 410.178

Address the following questions on Section 9.5.4.5.1 of the SSAR:

a. Is new fuel oil sampled in accordance with ASTM D4057?

b. Is the fuel oil tested in accordance with ASTM D975, ASTM 1552, and ASTM 2622?

c. Are particulate concentrations determined in accordance with ASTM D2276?

Response:

The above requirements originate from ANSI/ANS-59.51 - "Fuel Oil Systems for Emergency Diesel Generators" for safety-related equipment and exceed the diesel engine manufacturer's recommendations for commercial applications. Since the AP600 standby diesel generators are nonsafety-related equipment, it is anticipated that consideration will be given to the recommendations of the diesel engine manufacturer before final determination of the levels and frequency of fuels testing are established. Further, site-specific conditions can influence the final fuel specification requirements regarding pour point, cloud point and flash point temperatures of the fuel.

SSAR Revision: NONE

Question 410.179

Address the following questions regarding the diesel engine combustion air intake and exhaust system:

a. Describe how diesel generator exhaust gases are prevented from diluting or contaminating the combustion air intake. Are there any louvers, dampers, grills, etc. from which the exhaust gases could circulate back into the diesel generator building?

b. Is the combustion air filter module capable of reducing airborne particulate material over the entire time period that power is required, assuming the maximum airborne particulate concentration at the combustion air intake?

Response:

a. The diesel engine exhaust discharge elevation is approximately twenty feet higher than the combustion air inlet filters and the nearest building ventilation inlet air louvers. With exhaust gas temperatures of approximately 1000°F, the diesel exhaust gases have sufficient thermal buoyancy to rise or remain at elevations above the air inlets to the building or the engine.

b. The equipment procurement specifications for the diesel generators and the combustion inlet air filters will address the capability to perform at maximum airborne particulate concentration to prevent degradation of the engine performance in the event of tornados, dust storms, etc. It will also address the capability to perform for the period of time equivalent to the fuel resupply period

SSAR Revision: NONE

Question 410.180

Address the following questions regarding the diesel engine starting air system:

a. What is the number of successive times that the starting air system is capable of starting a cold diesel engine without recharging the receiver(s)?

b. Are alarms provided in the main control room that alert the operators that the air receivers have fallen bellow the minimum allowable value?

c. Is the starting air system supply air maintained with a dew point of at least 10 °F less than the lowest expected ambient temperature?

d. Is the starting air system capable of removing air particulate that could foul components in the system?

Response:

a. The diesel engine starting air system is designed to provide three consecutive starts of a cold diesel engine without recharging the starting air receivers with the normal coldest ambient temperature in the diesel generator building (50°F).

b. Alarms are provided in the control room to alert the operator that the starting air pressure is "LO". These are listed as the "Remote" annunciation points described in SSAR Table 8.3.1-1. The data display and processing system (DDS) will be used to provide this information.

c. The starting air system supply air will be at the normal diesel generator room temperature (between 50°F and 105°F). The system air dryers will be refrigerant type specified to a dew point temperature of 40°F which is 10°F below the lowest normal diesel generator room temperature.

d. The starting air system is shown on SSAR Figure 8.3.1-5 (sheets 1 and 2) and includes a compressor inlet suction air filter and an in-line filter in the compressor discharge piping to remove air particulate material that could foul the starting air system components.

SSAR Revision: NONE

Question 410.183

Describe how the AP600 design addresses the following recommendations of NUREG/CR-0660:

a. Moisture in starting air system

b. Dust and dirt in diesel generator room

c. Personnel training

d. Automatic prelube

e. Testing, test loading, and preventive maintenance

f. Improve identification of cause of failures

g. Diesel generator ventilation and combustion air systems

h. Fuel storage and handling

i. High-temperature insulation

j. Engine cooling water

k. Vibration of instruments

Response:

a. Moisture in the starting air system will be reduced by the design features of the starting air system. This will include refrigerated-type air dryers providing a maximum dew point temperature of 40°F to limit the amount of moisture in the stored starting air temperature. Interconnecting starting air piping will be stainless steel to limit the potential for rust and oxidation.

b. Dust and dirt in electrical contacts will be addressed in the equipment procurement specification, including the recommendations of NUREG/CR 0660. The inlet air supply system for the service module which contains most of the electrical switchgear and controls, is provided with filters to clean the cooling air.

c. Personnel training of diesel generator operating staff is the responsibility of the Combined License applicant.

d. The equipment procurement specifications for the diesel engine will require that the engine be provided with a continuous keep warm and prelube system which remains in operation while the engine is in standby mode.

e. The program for testing, test loading and preventive maintenance is the responsibility of the Combined License applicant.

f. Instrumentation is provided to support diagnostics during operation.

g. Recommendations of NUREG/CR 0660 were applied to the design of the AP600 diesel generator building ventilation and combustion air systems. Specifically:

- A separate outdoor filtered supply of combustion air is provided for the diesel engines

- The normal standby room air ventilation to the electrical equipment service module is filtered

The room ventilation/cooling system that operates when the diesel is in service utilizes low elevation inlet air louvers for non-filtered cooling air that is exhausted through roof vent fans after cooling the diesel room in one pass.

h. The AP600 diesel fuel oil handling and storage facilities include features that will permit the drainage of water from both the fuel storage tanks and the day tanks. In-line moisture removers and automatic drainers are provided in the transfer piping. The diesel generator engine driven fuel oil pump is supplied directly from the day tank to meet manufacturer's limitations on positive suction pressure on the engine driven pump. A fuel oil transfer pump powered by the associated diesel generator is used to supply the day tank from the main storage tank.

i. The equipment procurement specifications for the diesel generator electrical equipment will address the need for high temperature insulation.

j. The AP600 engine cooling water circuits are designed to use three-way thermostat water temperature control valves. These split the water flow between the cooling radiator circuit and the engine return inlet circuit such that the engine cooling inlet circuit temperatures remain nearly constant under various engine loads and ambient temperature conditions.

k. The effects of engine vibration on engine mounted monitoring and control instrumentation will be addressed in the equipment procurement specifications.

SSAR Revision: NONE

Question 410.197

Provide design criteria for penetrations between Nuclear Island (NI) buildings and non-NI buildings, and between NI buildings that prevent flooding between these buildings.

Response:

Flooding interfaces between buildings are addressed on a case-by-case basis in the flooding analysis described in SSAR Subsection 3.4.1. Buildings adjacent to the nuclear island are at grade elevation and provisions are incorporated to drain away from the nuclear island for all drains except radioactive drains. It is not necessary to eliminate flooding flows between buildings. Flow paths between buildings, along with the relevant flooding sources external to the nuclear island, are considered in the determination of the maximum flood heights in the nuclear island. The relevant flooding sources external to the nuclear island are bounded by flood sources within the nuclear island. Penetration between buildings below grade are sealed as described in the response to RAI 220.090.

SSAR Revision: NONE

Question 410.198

Include the February 25, 1993, response to Q410.39 regarding interior wall design and hydrostatic loads in the appropriate section of the SSAR. In addition, the SSAR should state that all walls, floors, doors, and penetrations should be able to withstand the maximum anticipated hydrodynamic loads associated with a pipe failure.

Response:

The SSAR will be revised as described below.

SSAR Revision:

Add the following new paragraph at the end of Subsection 3.4.1.1.2:

The following interior walls and slabs are considered as flood barriers in the flood evaluation described in Subsection 3.4.1.2.2. They are designed for hydrostatic loads up to the maximum flood level.

- boundaries of the RCS, PXS, and CVS compartments inside containment are designed for a flood level up to elevation 108′ 2″.
- the wall on line 7.3 between the radiologically controlled area and the nonradiologically controlled area may experience flooding of 17 inches above the base mat. It has no penetrations below elevation 100′.
- boundaries of the valve/piping penetration room (room 12306) on level 3 in the nonradiologically controlled area are designed for a flood level of 36 inches, except for the openings into the turbine building.
- boundaries of the MSIV compartments (rooms 12404 and 12406) on level 4 in the nonradiologically controlled area are designed for a flood level of 36 inches, except for the openings into the turbine building.
- the floor of the VBS B and D equipment room (room 12405) on level 4 in the nonradiologically controlled area is designed for a flood level of 12 inches.
- the floor of the VBS A and C equipment room (room 12501) on level 5 in the nonradiologically controlled area is designed to prevent water from running down into the main control room.
- the floor of the upper annulus (room 12556) is designed for a flood level of 6 inches.

The AP600 minimizes the number of penetrations through these walls below the flood level. Those few penetrations through flood protection walls that are below the maximum flood level are watertight. Any process piping penetrating below the maximum flood level either will be embedded in the wall or will be welded to a steel sleeve embedded in the wall. There are no watertight doors in the AP600 used for internal or external flood protection. The walls, floors, and penetrations are also designed to withstand the maximum anticipated hydrodynamic loads associated with a pipe failure as described in Section 3.6.

Question 435.78

There are substantial differences between the safety-related dc distribution system used in the AP600 PRA model and that described in the Chapter 8 of the SSAR. Table C17-8 of the PRA describes these differences and identifies the PRA impact due to these differences as "none." It is not obvious, however, that there is no impact on the PRA results due to these differences. For example, the PRA has modeled dc division A as two halfbuses with an open tie breaker between, while the Chapter 8 SSAR shows only a single bus. An assumed failure, therefore, of one bus results in only a partial loss of the division A dc loads in the PRA, while it results in a total loss of these loads based on the SSAR description. Also, the unavailability of the single spare battery and battery charger shown in the SSAR affects all four dc divisions since none of them then has a backup; whereas the unavailability of a single battery or charger in the PRA model only affects the division it is located in, since the remaining divisions each have available two battery banks and two chargers. Rather than trying to analyze away the substantial differences, the PRA model should be revised to accurately reflect the dc distribution systems described in Chapter 8 of the SSAR. This is also necessary to avoid confusion if the PRA is to be used later in the life of the plant as the basis for the ORAP program or some other maintenance or operating reliability program.

Response:

In the upcoming revision of the AP600 PRA, the dc power distribution system modeling will reflect the current dc power system design.

PRA Revision:

The PRA will be revised by December 31, 1994

SSAR Revision: NONE

Question 435.79

A comparison of Figure C16-1 of the PRA to Figure 8.3.1-1 of the SSAR on the ac power system shows a number of discrepancies between the two drawings. Table C16-8 identifies some, but not all, of these differences and indicates that they do not impact the PRA. While the differences are not as substantial as those on the dc systems discussed above, some of the discrepancies on Figure C16-1 are confusing. For example, Figure C16-1 shows a connection to a second offsite circuit that can feed one diesel generator bus and one reactor coolant pump bus; but it cannot be isolated from the normal power supply that feeds these buses. Figure 8.3.1-1, on the other hand, indicates that the second offsite circuit can feed any of the 4160V buses and can be isolated from the normal supply to these buses. Rather than trying to analyze away the differences, the PRA model should be revised to accurately reflect the dc distribution systems described in Chapter 8 of the SSAR. This is also necessary to avoid confusion if the PRA is to be used later in the life of the plant as the basis for the ORAP program or some other maintenance or operating reliability program.

Response:

In the upcoming revision of the AP600 PRA, the ac power distribution system modeling will reflect the current ac power system design.

PRA Revision:

The PRA will be revised by December 31, 1994

SSAR Revision: NONE

Question 435.82

Figure 8.3.2-2 of the SSAR shows continuous loads that are fed from inverters connected to the 24 hour battery banks. Since it is assumed that these loads will be energized throughout a 72 hour event until the 24 hour batteries are totally discharged, has the AP600 PRA or hazard analyses considered the effects of unintended equipment operations or anomalous instrument indications that might occur from operating under low battery voltages as this battery depletion occurs? Have the effects of battery cell reversal and subsequent gassing been considered with regard to the hydrogen concentrations in the 24 hour battery rooms over a 72 hour event?

Response:

The 24 hour 120V ac loads fed from the inverters are listed on the SSAR Tables 8.3.2-1 thru 8.3.2-4. The loads on the inverters are automatically transferred by the static transfer switch to the backup power supply when the inverter dc input power supply voltage drops to a setpoint of 100 volts. The dc input circuit breaker is subsequently tripped to turn off the inverter. The load transfer does not take place if the backup power from the regulating transformer is not available. The input circuit breaker trips and a trouble alarm is initiated. The battery cannot drain further since the input breaker to the inverter opens once the inverter dc input voltage reaches the setpoint of 100 volts at the end of battery duty cycle. The control logics are designed to be fail safe upon loss of power supply. Because of this undervoltage protection feature provided in each inverter, operation of the continuous loads at low battery voltages on all four divisions is avoided.

As indicated SSAR Tables 8.3.2-1 thru 8.3.2-4, the 125V dc loads on the 24 hour battery banks are non-continuous except for a few indicating lights loads. These non-continuous loads remain connected to the battery beyond the end of the duty cycle, but they operate only one time within the first minute of the duty cycle. Operations of these loads again and at less than acceptable voltage is avoided. The indicating lights may continue to operate beyond the duty cycle. However, the indicating lights load is very small with respect to a 2400 ampere-hour battery size. It is estimated to be 2.5 amperes per battery. According to one battery manufacturer, it can continue to operate with this small load beyond the 72 hour period without any adverse impact such as cell reversal and subsequent gassing.

Based on the above discussions, it is not necessary to consider the effect of unintended equipment operations or anomalous indications in the AP600 PRA or hazard analyses due to battery low voltage operations. There is no need to consider the effects of battery cell reversal and subsequent gassing with regards to hyrogen concentrations because the inverter is disconnected long before such stage of the battery is reached. The 125V dc continuous load from the indicating lights is so small that it does not have any adverse impact.

SSAR Revision: NONE

Question 440.60

Provide a description of the design features and procedure guidance that are incorporated into the AP600 design to minimize the likelihood and consequences of loss of ac power during outage activities.

Response:

The AP600 electric power systems design features are described in Chapter 8, Sections 8.1.2, 8.2, and 8.3 of the SSAR. These design features provide access to three independent power supply sources during outage activities. The preferred power supply for outage activities is from the switchyard backfeeding through the main stepup and unit auxiliary transformers. The second power supply, the maintenance power supply, is provided through a reserve auxiliary transformer. The maintenance power source is site-specific and does not depend on the plant main stepup transformer, unit auxiliary transformers or the isophase bus system. The third power supply source for outage activities is provided from the two onsite standby diesel generators.

If the preferred power supply is not available due to a failure or maintenance of the main stepup and auxiliary transformers the power is provided from the maintenance source through a reserve auxiliary transformer. The reserve auxiliary transformer is sized to replace one unit auxiliary transformer. It has the capacity for operating the loads required during outage activities. The medium voltage (4.16kV) busses are connected to the reserve auxiliary transformer through normally open circuit breakers. The busses are transferred to the maintenance source manually.

In the event of a loss of the preferred and maintenance power supplies, each onsite standby diesel generator can provide power necessary to achieve and maintain safe shutdown conditions. The automatic load sequencer provided for each generator allows connections of the various plant system electrical loads that enhance an orderly plant shutdown under emergency conditions. SSAR Subsection 8.3.1.1.2.3 describes the design features of each onsite standby diesel generator.

Table 10.3-3 of Reference 440.60-1 provides short-term availability recommendations for ac power sources during reduced reactor coolant system inventory operations in Modes 5 or 6. The maintenance of affected power supply components should normally be scheduled during Mode 1 for the diesel generators and Modes 2, 3, or 6 (without reduced inventory conditions) for the other power system components.

Reference:

440.60-1 WCAP-13856, Rev. 0, AP600 Implementation of the Regulatory Treatment of Nonsafety-Related Systems (RTNSS) Process

SSAR Revision: NONE

Question 440.73

Section 3.9.4 of the SSAR indicates that the CRDS is the same as that presently used in current Westinghouse designs. The Control Rod Position Monitoring System (CRPMS) in the current CRDS is, although a proven system, a very old monitoring system (such as the "Analog Rod Position Indication System"). What modifications, if any, will be made to the design of the system prior to implementing it in the AP600 to correct the operational problems that have been associated with the current design?

What modifications, if any, will be made to the design of the CRPMS to correct the analog and digital rod misalignment problems and recent control rod maneuverability problems (for instance, rods moving in when they should be moving out) that have occurred with the CRPMSs in current operating plants? The individual rod position indicators are sensitive to temperature and rod movement. Technical Specification (TS) changes have been necessary to allow for recalibration at beginning of cycle (BOC) for thermal soak and for adjustment after rod movement. Additional TS changes have been requested by the operators of current operating plants because of the frequency of rod misalignments greater than 12 steps. In addition, it has been necessary to change the definition of "fully withdrawn" control rods because of vibrational wear on the guide tubes in many plants. If the present CRMS will be implemented in the AP600, describe how these rod misalignments, vibrations, and erroneous rod motion problems will be corrected, and what improvements in the CRDS have been made. Provide technical justifications for these modifications. (See also Section 4.6.1).

Response:

As stated in SSAR Subsection 3.9.4, the AP600 control rod drive mechanism is based on a proven design that has been used in many operating nuclear power plants. The AP600 rod control and rod position monitoring systems take advantage of digital and microprocessor-based instrumentation and control technology to provide enhanced reliability and operation.

The AP600 uses the Westinghouse Microprocessor Rod Position Indication (MRPI) System for rod position indication. The AP600 system uses a digital sensing technique to eliminate the problems inherent in the analog system. As stated in the SSAR Subsection 3.9.4, the control rod position is measured by 42 discrete coils mounted on the position indicator assembly surrounding the rod travel housing. The use of this digital system eliminates apparent rod misalignments that occurred in plants using the analog rod position indication system.

Control rod position was not a contributor to the "recent control rod maneuverability problems." The single rod withdrawal incident that occurred on May 27, 1993 at the Salem Nuclear Generating Station, Unit 2 was caused by two printed circuit card failures in the solid state rod control system. These failures resulted in corrupted signals being applied to the control rod drive mechanism grippers, causing the single rod withdrawal. The most probable cause of these failures has been identified as being voltage transients generated by the system's demand step counters.

Design changes to eliminate this type of failure in plants using the solid state rod control system include design changes that minimize the voltage transients caused by the electromagnetic demand step counters, and system timing

changes that change the control rod drive mechanism gripper operation to prevent the of corrupted signals from causing a rod withdrawal. The AP600 uses a microprocessor rod control system which does not use electromagnetic demand step counters. In addition, system timing and logic are controlled by a microprocessor rather than the discrete logic gates used in the solid state rod control systems.

Flow induced vibrational wear in the rod control system has been addressed in the AP600 by a combination of design changes. These changes include material changes, reducing the guide tube flow, and redesigning the guide cards to make them thicker and to provide continuous support.

SSAR Revision: NONE

Question 440.74

Section 5.2.2.2 of the SSAR states that an over-pressure protection report is prepared according to Article NB-7300 of Section III of the ASME Code. Provide this report.

Response:

An over-pressure protection report is prepared for the standard AP600 design. It includes safety analysis and evaluations of credible over pressure events and hardware documentation. For each AP600, a unique over-pressure protection report endorsement is prepared to state that no deviation from the standard exists or that any deviations have received the same level of protection as in the standard. This report will be referenced in the N-Stamp documentation.

SSAR Revision: NONE
PRA Revision: NONE

Question 440.80

Section 5.2.2.1 of the SSAR states that administrative controls and plant procedures aid in controlling the reactor coolant system during low temperature operation, and that normal plant operating procedures maximize the use of a steam or gas bubble in the pressurizer during periods of low pressure, low temperature operation. Discuss the operator actions required for low temperature operation for the conditions when a steam bubble or gas bubble exists in the pressurizer and for a water-solid pressurizer.

Response:

Low temperature operations occur when RCS temperature is less than or equal to the initiation temperature of the normal residual heat removal system (RNS)--350°F. A steam bubble is maintained in the pressurizer during most of the low temperatures operations. Water-solid operations are limited to RCS venting operations prior to plant heatup operations and pressurizer cooldown operations at the end of plant cooldown. During low temperature operations, the operators maintain RCS pressure within the range to satisfy both reactor coolant pump (RCP) net positive suction head (NPSH) requirements and the material ductility limitations of the reactor vessel (Technical Specification 3.4.3).

When a steam bubble is present in the pressurizer, normal or auxiliary spray and the pressurizer heaters control RCS pressure. RCS inventory control is accomplished by injecting makeup via the CVS makeup pump on demand either by the automatic pressurizer level control system or by the operators.

When the RCS is water solid, the operators control RCS pressure and inventory by managing the balance of the makeup flow to and the letdown flow from the RCS via the CVS and RNS. For this operation, the CVS operates in an "open loop" configuration, with letdown to the waste liquid system effluent holdup tanks, and makeup provided via the CVS makeup pumps taking suction from the effluent holdup tanks.

Pressurizer temperature is controlled by the pressurizer heaters and the normal or auxiliary spray. During plant startup, the RCS heatup is accomplished by the continuous operation of the RCPs. RCS temperature control is accomplished by intermittent operation of the normal residual heat removal system. During plant shutdown, RCS temperature control is accomplished by continuous operation of the normal residual heat removal system.

SSAR Revision: NONE

Question 440.83

Section 5.2.2 of the SSAR states that the steam system over-pressure prot[illegible] power operation is provided by the main steam safety valves (MSSVs), which have the capacity of providing [illegible] relief to remove 102 percent of rated steam flow to limit the steam system pressure to less than 110 percent of [illegible] steam generator shell side design pressure. Section 10.3.2.2.2 of the SSAR states that a total MSSV-rated capacity of 105 percent of the design steam flow meets the requirement for preventing the steam system pressure from exceeding 110 percent of the main steam design pressure following a turbine trip. Clarify the difference in the required MSSV relieving capacity in these two statements.

Response:

The requirement in Section 10.3.2.2.2 of the SSAR is correct.

SSAR Revision:

The second last paragraph of Section 5.2.2.1 of the SSAR will be revised to read:

Overpressure protection for the steam system is provided by steam generator safety valves. The capacity of the steam system safety valves ~~is based on providing enough relief to remove 102 percent of rated steam flow. This must be done while limiting~~ limits steam system pressure to less than 110 percent of the steam generator shell side design pressure. See Section 10.3 for details.

Question 440.98

During transients or accident events, the core makeup tank injects cold water through the direct vessel injection line. What analyses or tests have been performed to demonstrate that the thermal and vibration effects of direct vessel injection on the reactor vessel or reactor internals are acceptable?

Response:

The above transients are specified as design transients for the reactor vessel and the reactor internals. It will be shown that they meet the applicable stress limits for these transients. The internals have been evaluated for flow induced vibration for normal operating flow and pump overspeed flow conditions, which are much higher flows than the core makeup tank injection flow. Also note that the rapid CMT injection flows are of a short duration, less than an hour, which are less significant for vibration effects. RAI 210.98 discusses how thermal stratification is addressed.

Current Westinghouse designed two loop plants have direct vessel injection nozzles that accommodate RHR and HHSI pumped injection. These plants are designed and analyzed for injection flows of about 2000 gpm (per DVI nozzle) during low head safety injection operation. This flow is higher than the AP600 core makeup tank injection flow which is about 800 gpm (per DVI nozzle). Based on the two loop design experience, it is not anticipated that there is a problem with the AP600 reactor vessel and the reactor internals during CMT injection.

SSAR Revision: NONE

Question 440.106

Section 6.3.2.5.3 of the SSAR states that for those valves that reposition to initiate safety-related system functions, the valve repositioning times are less than the times assumed in the accident analyses. It further states that it is acceptable for the CMT injection to be delayed several minutes due to high initial steam condensation rate.

a. The proposed Technical Specifications do not provide a definitive requirement regarding the valve repositioning time. For example, Surveillance Requirement 3.5.2.4 specifies verification of the CMT inlet and outlet isolation valves to be operable every 92 days without defining the valve repositioning times or what constitute operability of the valves. Describe how the valve delay times are controlled in the TSs and how surveillance is made to ensure the actual delay times are shorter than assumed in the safety analysis?

b. Describe how the CMT injection delay time is accounted for in the safety analysis and what verification is performed to ensure that this is a conservative value.

Response:

a. Valve stroke times are verified through the in-service testing (IST) program. RAI 210.24 provides a revision to SSAR section 3.9.6 that specifies that the valve stroke time requirements will be verified during periodic valve stroke testing, which is done on a quarterly basis for most valves. Table 3.9.6-1 defines the safety-related valve missions (opening and/or closing) and stroke test frequency. The valve stroke times will be verified against limits used in the safety analysis.

Overall systems level response time (ESF response time) is verified by testing required by the Technical Specifications. The ESF response time is defined in Section 1.1 of the Technical Specifications as follows:

> "The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, etc.)."

The ESF response time surveillance (SR 3.3.2.5) has been specified for equipment actuations for which times have been assumed in the SSAR Chapter 15 safety analysis. The CMT valve actuation response time surveillance is as specified in LCO 3.3.2, ESFAS Instrumentation, Table 3.3.2-1, Function 2. Surveillance (SR 3.3.2.5) verifies that the signal delay plus the valve repositioning time along with the other portions of the response time interval meet the safety analysis value. This surveillance is performed every refueling outage. The ESF response times will be verified against limits used in the safety analysis

b. In the AP600 SSAR Chapter 15 safety analyses, three sources of delay in the injection of CMT inventory are considered:

- Electronic signal delay; time from plant parameter exceeding setpoint to when valve actuation signal is generated.

- Valve opening delay; time from when valve receives actuation signal to when valve completes its operation. Minimum, maximum and nominal stroke times are defined. These times are used as appropriate in the different safety analysis.
- CMT steam condensing related delays; time from when steam enters the CMT (after the cold voids) until the CMT achieves full injection flow. This delay only occurs when the top of the CMT is not heated by water recirculation prior to steam entering the CMT from the cold legs. Note that during this delay time the CMTs provide injection at a reduced rate.

The electronic signal delay is taken to be 1.2 seconds. This delay applies to LOCAs where a CMT actuation signal is generated by a containment high pressure or a pressurizer low pressure signal. It also applies to non-LOCAs where the CMT actuation is generated by a pressurizer low pressure, a cold leg low temperature or a SG low pressure signal.

The valve opening delay is modeled in the large break LOCA SSAR analysis to open linearly over a fifteen second time span, which is the average of the nominal and the maximum anticipated opening times of this valve. This assumption delays CMT flow delivery which is conservative for a large LOCA. In the small break LOCA SSAR cases, a valve opening time of five seconds is applied, which is the minimum valve opening time for the CMT isolation valve. Since in small LOCAs the core behavior is insensitive to small variations in the initiation of CMT flow a fast valve opening time results in a more rapid CMT draining, thus minimizing the calculated system inventory.

The CMT valve opening delay is modeled in non-LOCA analysis assuming a step function after the signal response and valve stroke delay. A short delay (5 seconds) or a long delay (10 seconds) for valve stroke time is used depending upon the conservative direction for the event being analyzed. For example, the steam line break event used a conservatively long delay to minimize the amount of boration contributed by the CMT. Conversely, analysis of inadvertent actuation of the CVS used conservatively short delay times.

The CMT steam condensing delay is accounted for in the thermal hydraulic models of the CMT. The CMT models account for the possibility of steam condensing delay in a mechanistic way. They require the top portion of the CMT water to be heated to saturation before a steam bubble can form and the CMT begin to drain. In many events there will be no steam condensing delay either because no steam enters the CMT (as in non-LOCA events) or because the CMTs initially recirculate hot water from the cold legs before the cold legs void and steam enters the CMTs (as in smaller LOCAs). There are some events (such as larger LOCAs) where the cold legs void quickly, and the water in the top of the CMTs is cold when steam flows up from the voided cold legs. In this situation, the steam entering the CMT condenses until the top portion on the CMT heats to saturation. During this heatup period the CMT injection is reduced relative to its full capability. These CMT models will be verified against the CMT test results.

SSAR Revision: NONE

Question 440.167

The following questions pertain to the analysis of a main steamline break (MSLB) contained in the February 15, 1994 report on AP600 design changes.

a. Confirm that the analysis shown in the report assumes actuation of both passive residual heat removal (PRHR) heat exchangers (HXs) at time zero.

b. Is a failure of one CMT discharge MOV assumed, as stated in the original analysis in the SSAR?

c. Is there any other single active failure that could result in more limiting conditions, i.e., further draining of a CMT tank prior to system stabilization?

d. Has the actuation of non-safety-related systems that could exacerbate the consequences of the event been taken into account? If so, explain the assumptions that have been made. If not, show that non-safety systems cannot have negative impacts.

e. What assumptions have been made with respect to the temperature of the IRWST water and associated uncertainties, and the resultant impact on PRHR HX outlet temperatures?

f. What assumptions have been made with respect to PRHR heat transfer coefficients and associated uncertainties, and the resultant impact on PRHR HX outlet temperatures?

Response:

Subsequent to the submittal of the February 15, 1994 report on AP600 design changes (Reference 440.167-1), additional modifications have been made to the AP600 design. Formal documentation supporting the implementation of these design changes has been submitted to the NRC in a separate transmittal (Reference 440.167-2). Included among these changes is the removal of the pressurizer balance line, which has an impact on certain aspects of the steamline break transient results originally presented in Reference 440.167-1 and under further consideration here.

One of the issues addressed for the steamline break transient has been the minimum predicted CMT water level. The initiating signal for Stage 1 ADS is CMT water level and it is an AP600 design goal that ADS not actuate during non-LOCA events. With the pressurizer balance line in place, the CMT water level will fall whenever the volumetric injection flow rate into the RCS exceeds that into the CMT via the cold leg balance line. This condition is predicted to occur during portions of the limiting steamline break transient. However, the removal of the pressurizer balance line alters the behavior of the CMT during the injection phase of operation.

Specifically, without the pressurizer balance line, the CMT will operate only in the recirculation mode throughout the non-LOCA events. This means that any injection flow into the RCS is offset by an equal volumetric flow into the CMT via the cold leg balance line. Because of density differences between the fluid entering and leaving the CMT, the mass of water in the CMT does decrease during the early phase of recirculation. However, the volume

of water in the CMT remains unchanged, with the tank water solid and the possibility of ADS actuation on low CMT water level is thereby precluded.

Since the explicit steamline break analysis results reported in Reference 440.167-1 address unintended ADS actuation, the removal of the pressurizer balance line effectively eliminates that entire issue as a concern for the non-LOCA transients. On this basis, it would be reasonable to suggest that a response to question 440.167 is not necessary since the subject analysis is no longer applicable. However, for the sake of completeness, a response to that question is being provided.

a. The steamline break analysis results provided in Reference 440.167-1 does assume the actuation of both PRHR heat exchangers at time zero.

b. The modeling assumptions for the steamline break analysis presented in Reference 440.167-1 are intended to maximize injection flow from the CMTs to the RCS while minimizing the recirculation flow from the RCS into the CMTs via the cold leg balance lines. This combination of assumptions produces the largest reduction in CMT water volume with the nearest approach to the ADS actuation setpoint. Consistent with this set of assumptions, the subject analysis does not assume the failure of one CMT discharge MOV. Both valves are assumed to operate since this maximizes injection flow from the CMT to the RCS.

c. As discussed in Section b., above, the analysis assumptions are intended to minimize flow into the CMT via the cold leg balance line. Consistent with this assumption, the analysis models a maximum flow resistance in the cold leg balance line. This maximum resistance is consistent with the failure of one MOV in the cold leg balance line.

d. The actuation of non-safety-related systems that could exacerbate the consequences of the event has been taken into account. Specifically, maximum startup feedwater flow has been assumed to occur at time zero. This assumption maximizes the cooldown of the RCS.

e. The analysis assumes a minimum temperature in the IRWST. Specifically, an initial IRWST temperature of 70 °F. This minimum temperature is consistent with the general assumptions for the steamline break analysis that maximize the cooldown of the RCS.

f. Consistent with the general approach of maximizing the cooldown of the RCS, maximum heat transfer characterisitcs have been assumed for both PRHR heat exchangers.

References:

440.167-1 AP600 Design Change Description Report, February 15, 1994, Enclosure to Westinghouse letter NTD-NRC-94-4064.

440.167-2 AP600 Design Change Description Report, June 30, 1994, Enclosure to Westinghouse letter NTD-NRC-94-4175.

SSAR Revision: NONE
PRA Revision: NONE

Question 440.168

Provide a description of how the operator brings the AP600 plant from "safe shutdown" conditions (about 400°F and a few hundred psi) to cold shutdown conditions. Specifically, provide the following information:

a. If the operator initiates plant cooldown from safe shutdown conditions by using the non-safety active systems, discuss how this evolution is accomplished and the associated thermal-hydraulic phenomena that will occur.

b. If the plant is at safe shutdown conditions or is in transition from safe shutdown to cold shutdown and loss of normal (non-safety) RHR occurs, discuss how the operator is to respond, either by bringing the passive safety systems on-line, or by use of alternate non-safety systems.

c. The evolutions described in Items a and b above also involve mode changes. Provide assurance that these transitions (swapping systems) can be made smoothly. Describe operator actions (man- machine interface) and thermal-hydraulic system behavior during the mode changes.

d. Discuss the method for incorporating actions discussed above into procedures. This discussion should include the basis supported by analysis and testing for proceduralizing the actions. Also, identify plant configurations that may occur during maintenance and alternate decay heat removal methods, and assess their overall effect on the plant. For example, how will RHR be accomplished (1) during loss of active shutdown cooling at cold shutdown with the RCS closed, (2) during midloop operations, and (3) with the RCS open?

Response:

a. During safe shutdown conditions, RCS heat removal is achieved by operation of the passive RHR heat exchanger. During the transition to cold shutdown conditions, the RCS heat removal is achieved via the steam generators fed by the startup feedwater pumps at RCS temperatures above 350°F, and via the normal residual heat removal system (RNS) at temperatures below 350°F. When in safe shutdown, the most likely scenario is that the reactor coolant pumps are not running. Therefore, to improve RCS heat removal via the steam generators, the RCPs are started to circulate coolant through the core and the steam generators. The chemical and volume control system is operated to establish the required boron concentration and also to establish a normal level in the pressurizer if required. The startup feedwater pumps, aligned to take suction from the deaereator, are started and feed the steam generators. The startup feedwater pumps remove heat from the RCS until the RCS temperature is reduced to approximately 350°F. Normal pressurizer spray is used to reduce the pressure in the RCS to below the cut-in pressure for the RNS. At that point, RNS operation is initiated, and plant cooldown to cold shutdown conditions continues. The startup feedwater pumps continue to deliver water to the steam generators to cool the secondary side of the steam generators.

b. During normal plant cooldown, and during the scenario described above, if the RNS is lost, the operator attempts to cool the RCS via the steam generators and startup feedwater pumps. If this system is also unavailable, the operator opens the passive RHR isolation valves to actuate passive RHR heat exchangers. The operator also closes the RNS inner and outer suction isolation valves to re-establish the reactor coolant pressure boundary in case of a re-pressurization of the RCS. The passive RHR heat exchangers would maintain the RCS conditions

at or below the safe shutdown conditions. The RCS temperature may increase at the onset of the loss of the RNS, but would stabilize at a safe shutdown temperature and pressure.

c. Technical specifications and mode definitions are not intended to cover accident scenarios, but rather normal plant operation. The above scenarios describe the transition from operation with the passive safety-related systems to the active, nonsafety-related auxiliary system. This transition is an accident recovery operation, and is covered by emergency operating procedures and not technical specifications. Therefore, it is not appropriate to equate the transition from Mode 3 to Mode 4 with the transition from passive system operation to active system operation. The responses to items (a) and (b) describe operator actions (man- machine interface) and thermal-hydraulic system behavior during the transition from the passive systems to the active systems. Normal transitions from mode 3 to mode 4 will occur using only the active systems, and will be very similar to current PWRs. Normal plant cooldowns are described in SSAR section 5.4.7.

d. SSAR Chapter 18 describes the process that will be followed to develop the AP600 man-machine interface including the plant procedures. As discussed with the NRC staff on January 22-23, 1992 and November 19, 1992, the process described in Chapter 18 is provided for design certification. The results of the process, including the specific Emergency Response Guidelines, will be provided by the COL applicant. In addition to describing the process that will be used to develop AP600-specific Emergency Response Guidelines, Subsection 18.9.8 also provides the high-level operator action strategies for emergency operations.

As stated in Subsection 18.9.8.1.1, the development of the AP600-specific Emergency Response Guidelines is based on the Westinghouse low-pressure Emergency Response Guidelines. Reference 440.168-1 provides a comparison of the low-pressure ERG reference plant system designs to the AP600 system designs to identify the design differences.

Westinghouse has also prepared a set of matrices and figures depicting event mitigation strategies and levels of defense-in-depth. The matrices and figures are provided in Reference 440.168-2. These matrices and figures together with the high level operator action strategies included in SSAR Chapter 18 and the design differences document provide information for assessing the role of the operator in event mitigation.

The response to RAI 440.063 discusses the AP600 performance to events that occur at shutdown. The AP600 passive safety-related systems provide the safety-related means for protecting the plant during all modes of operation including shutdown and refueling. Shutdown events and midloop operations were evaluated in the AP600 PRA. Results indicate a low contribution to core damage from shutdown events. In addition, shutdown events were included in the RTNSS implementation.

For events that occur at hot shutdown, hot standby, or cold shutdown (prior to reduced inventory operations), the full compliment of passive safety-related systems are available to mitigate an event. For reduced inventory conditions, the passive RHR heat exchangers, accumulators, and core makeup tanks are unavailable or ineffective. Prior to and during reduced inventory operations, precautions are taken such as opening the ADS valves connected to the pressurizer and assuring containment closure capability. During midloop operation, protection is provided by IRWST injection (motor-operated isolation valves in the injection line are closed and operable). These isolation valves are manually opened following a loss of normal RHR, ac power, or low RCS

inventory. In addition, these valves receive signals from the nonsafety-related diverse actuation system to automatically open on a loss of RCS inventory (after a 30 minute time delay).

References:

440.168-1 WCAP-14075, AP600 Design Differences Document for Development of Emergency Guidelines Report, May 1994.

440.168-2 WCAP-13793, AP600 Systems / Events Matrix, June 1994

SSAR Revision: NONE

Question 440.177

Many of the sequences in the PRA, OK or core damage, do not appear to be explicitly supported by code runs, or if they are supported, the documentation does not make it clear. Establish a correspondence between the code runs, the tests, and the mission success criteria in the event tree sequences. Provide the following information:

a. Provide, for each IE modelled in the PRA, a table showing the initial conditions and status of every system modelled in each run, including how many trains of each system that functioned during the run, the peak clad temperature calculated, and the length of time the analysis was carried through.

b. In a separate table for each IE, list all the OK sequences and the code runs and tests that confirm the scenario defined by the sequence, including the timing of events and success criteria. If some sequences were not analyzed because they were believed to be bounded by others, indicate [illegible] sequences are treated in this way, and why the case analyzed is considered more bounding. If particu[illegible]nts of the testing program correspond closely to a particular code run confirming success path perf[illegible] generate a roadmap establishing the correspondence between the testing program and the applicable code runs.

The response to this question can also be used to address many of the questions Q440.178 through Q440.189.

Response:

Information in response to this question will be provided in Sections 6 and 7 of the AP600 PRA, Rev. 2.

SSAR Revision: NONE

PRA Revision:

The information requested will be provided in Revision 2 of the PRA scheduled for December 31, 1994.

Question 440.183

Provide the following information with respect to the ATWS event tree in Figure F-21 of the PRA (see also Q440.177):

a. In sequences 6 and 23 with both the CMT and the PRHRS available, no code run was done for a "prolonged" ATWS to support the ADS success criteria. The assumed success criteria for this case are the same as for the non-ATWS transients where the CMT is available and the PRHRS is failed. The implicatioa of this is that the impact of the ATWS is canceled out by the operation of the PRHRS. What analysis supports this conclusion?

b. In sequences 12 and 29, where the CMT is failed and both accumulators and the PRHRS are available, no code run was done to support the ADS success criteria in the "prolonged" ATWS. The assumed success criteria are the same as that for the non-ATWS transients where the CMT failed, the accumulators are available, and the PRHRS failed. The implication of this is that the impact of the ATWS is canceled out by the operation of the PRHRS. What analysis supports this conclusion?

Response:

The analysis supporting these conlcusions will be provided in Section 6 of the AP600 PRA, Rev. 2.

SSAR Revision: NONE

PRA Revision:

The information requested will be provided in Revision 2 of the PRA scheduled for December 31, 1994.

Question 440.185

In many of the event trees in the PRA, CMT success is taken to be "flow from one CMT," and whenever one CMT succeeds, there is no decision point for the accumulators. This implies that success is claimed for all of the following cases: (a) 1 CMT, 0 ACC, (b) 1 CMT, 1 ACC, (c) 1 CMT, 2 ACC, (d) 2 CMT, 0 ACC, (e) 2 CMT, 1 ACC, (f) 2 CMT, 2 ACC.

Each event tree success path may correspond to different hardware success/failure combinations, with physical outcomes that differ significantly from each other while still satisfying the peak cladding temperature criterion. In the AP600 design, it may not be the case that more injection is always better, and it is therefore necessary to identify which of the above cases are the most unfavorable, which may depend on failure configurations of ADS valves. For each success path on the event trees for which more than one hardware configuration may correspond to "success," which of these hardware configurations is most limiting in terms of PCT? What code runs establish this conclusion? For the most limiting case of each success path, what is the temperature history of the core (see also Q440.177)?

Response:

Information in response to this question will be provided in Sections 6 and 7 of the AP600 PRA, Rev. 2.

SSAR Revision: NONE

PRA Revision:

The information requested will be provided in Revision 2 of the PRA scheduled for December 31, 1994.

Question 440.186

Provide the following information for the SGTR event tree in Figure F-20 of the PRA (see also Q440.177):

a. In the SGTR tree, there are a number of success paths (9-2, 10-2, 11-2) involving CMT success when the CVS fails to trip. However, apparently no code runs were performed for the case in which the CVS fails to trip. What is the basis for these success paths?

b. In the SGTR tree, there are a number of success paths (6-2, 11-2) involving CMT success when steam generator (SG) isolation fails. However, it appears that no code runs were performed for the case in which SG isolation fails. The most-closely-corresponding run involves failure of a secondary PORV to reclose, followed by auto-isolation. What is the basis for these success paths?

c. For SGTR scenarios (2,10) in which the PRHRS is operating, modelling suggests that the CMT will discharge and actuate the ADS, thereby depressurizing the RCS. However, LOFTTR2 runs indicate that CMT discharge will not occur, and thus the ADS will not be actuated. Explain this discrepancy.

Response:

Information in response to this question will be provided in Section 6 of the AP600 PRA, Rev. 2.

SSAR Revision: NONE

PRA Revision:

The information requested will be provided in Revision 2 of the PRA scheduled for December 31, 1994.

Question 440.187

In the steamline break trees (SLD, SLO, SOV) of the PRA, it is assumed that one CMT is sufficient to mitigate the event. It is also assumed that the CMT discharge is small enough that the ADS will not be actuated. The only code run associated with this case is a LOFTRAN/THINC run with 2/2 CMT and 2/2 ACC available. What is the basis for concluding that with 1 CMT available, the ADS will not be actuated? Why is the CMT needed at all? If no makeup is provided, will shrinkage result in core damage? For purposes of this concern, both "isolation" and "no isolation" cases should be considered (see also Q440.177).

Response:

Information in response to this question will be provided in Sections 6 and 7 of the AP600 PRA, Rev. 2.

SSAR Revision: NONE

PRA Revision:

The information requested will be provided in Revision 2 of the PRA scheduled for December 31, 1994.

Question 440.188

In sequences 2 and 10 of the SGTR event tree, sheet 2 of Figure F-20 of the PRA, if stage 4 of the ADS is actuated with no Stage 1-3 actuated, what is the effect on the PRHR from the loadings? Can the PRHRS with only one heat exchanger (HX) cool the RCS down to where Stage 4 can work with no Stage 1-3 opening? Can the PRHRS with only one HX cool down to equalize RCS pressure to secondary side pressure? Is there a gap release for any configuration implicitly credited as PRA success? (For example, PRHRS + 1/2 Stage 4 ADS, the most adverse CMT + Accumulator operation, etc.). If so, the event tree structure describes as "OK" some of the events in which the SG is not isolated. What are the releases in that case (see also Q440.177)?

Response:

Information in response to this question will be provided in Sections 6 and 7 of the AP600 PRA, Rev. 2.

SSAR Revision: NONE

PRA Revision:

The information requested will be provided in Revision 2 of the PRA scheduled for December 31, 1994.

Question 440.193

In the safety path using the PRHRS (PRT), does the loss of instrument air, T_{CA}, interfere with throttling the PRHRS?

Response:

Loss of instrument air causes PRHR heat exchanger outlet valves V108A and B to fail open, defeating the capability to throttle the PRHR system. Inlet motor-operated valves V102A and B cannot be used to throttle flow to the heat exchangers. This is not considered to be significant to safety. The impact on the plant is bounded by the safety analysis in SSAR Section 15.1.6, addressing spurious PRHR operation. In this analysis, maximum heat removal with both heat exchangers operating is considered, conservative assumptions and methods are used, and acceptable results are shown.

Although PRHR system throttling is defeated by a loss of instrument air, there are several alternative methods of reducing the amount of heat transferred to the IRWST through the PRHR heat exchangers:

1. Motor-operated valves V102A and B can be used to isolate one of the heat exchangers.

2. Tripping the reactor coolant pumps reduces the flow rate through the heat exchangers.

3. As the temperature of the primary coolant decreases, the natural circulation flow rate through the heat exchangers also decreases.

PRA Revision: NONE

SSAR Revision: NONE

Question 440.200

It appears that given a LOCA of any size, even a very small-break LOCA, part of the expected plant response is to use full ADS actuation. Is this correct? If yes, the frequency of full ADS actuation is higher than the frequency of LOCAs that is approximately 2E-03 per year. Is this accurate?

Response:

Automatic depressurization system actuation is not expected for reactor coolant system leaks and very small LOCAs (<3/4"). As discussed in Reference 440.200-1, the chemical and volume control system has the capability to cope with these events. For small LOCAs up to one inch, the chemical and volume control system, in conjunction with core makeup tank injection provides sufficient makeup to bring the plant to shutdown prior to automatic depressurization system actuation. Therefore, the frequency of full automatic depressurization system actuation is not higher than the frequency of LOCAs.

Not every automatic depressurization system actuation leads to opening of the fourth stage automatic depressurization system valves (which causes high containment pressure and temperature and containment floodup). If the normal residual heat removal system is available, its injection stops the core makeup tank draindown and prevents the fourth stage automatic depressurization actuation. As discussed in Reference 440.200-2, the results of the initiating event frequency evaluation included in the RTNSS implementation, do not identify any RTNSS significant nonsafety-related SSCs with respect to these intitiating events.

References:

440.200-1 WCAP-13793, "AP600 System / Event Matrix," June 1994.

440.200-2 WCAP-13856, "AP600 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process, Summary Report," September 1993.

SSAR Revision: NONE

Question 440.212

What assumptions are made regarding maintenance unavailability of equipment during shutdown?

Response:

In the PRA, Revision 0, it is assumed that planned maintenance of the safety-related systems will be performed during shutdown with the reactor cavity flooded. In this condition, the water in the cavity provides the safety-related decay heat removal. Therefore, maintenance unavailability of equipment during shutdown does not impact the plant safety functions.

Planned maintenance on nonsafety-related equipment/systems will be performed during different modes of operation. The modeling of nonsafety-related systems in the PRA is consistent with planned maintenance of these systems as shown below:

MAINTAINED SYSTEM	OPERATING MODE
CVS, DAS, PLS	6
SFW	5 or 6
RNS, CCW, SW	1
SFS	1 through 5

PRA Revision: NONE

SSAR Revision: NONE

Question 440.213

Why are steam generators or reflux cooling not credited for in the event trees for mid-loop operations?

Response:

The AP600 design provides redundancy and diversity in operation of the normal residual heat removal system or gravity injection through the IRWST to remove decay heat while at mid-loop. The PRA, Revision 0, results indicate that loss of the normal residual heat removal system during midloop operation contributes about 95% to the shutdown core damage frequency (CDF), and the shutdown CDF makes up approximately 20% of the overall core damage frequency (CDF). The AP600 CDF is more than 2 orders of magnitude less than its goal. Inclusion of the steam generators or reflux cooling in the model would provide additional capability which is unnecessary.

Inclusion of steam generator cooling would unnecessarily complicate the AP600 PRA.

Based on the above considerations, no credit is taken for steam generators or reflux cooling during shutdown operation.

PRA Revision: NONE

SSAR Revision: NONE

Question 440.223

In sequence 1 of the SGTR event tree of the PRA, the CVS trips and the PRHRS succeeds. What equalizes the pressure between the primary side and secondary side of the ruptured SG? What happens in the long run? It seems that the use of the PRHRS has the disadvantage of creating steam inside the containment making cleanup a difficult task. Why is cooling the IRWST not taken credit for?

Response:

As shown in the analysis provided in SSAR Subsection 15.6.3, following a steam generator tube rupture, the passive residual heat removal heat exchanger operation provides the reactor coolant system cooldown. The reactor coolant system cooldown results in a primary side pressure reduction that equalizes the primary / secondary side pressures of the ruptured steam generator. The pressure equalization stops the primary to secondary side flow.

In the long term, the continuous operation of the passive residual heat removal heat exchanger slowly decreases the reactor coolant system temperature and pressure, and controls the steam generator depressurization.

Steaming to the containment resulting from passive residual heat removal operation is unlikely. As shown in Reference 440.223-1, the initial responses to this event are as follows:

- If the nonsafety-related, active systems (chemical and volume control system and startup feedwater) are available, operator actions can avoid passive residual heat removal system operation.

- If the passive residual heat removal heat exchanger operation is required, steaming to the containment is avoided if the normal residual heat removal system is used to cool the in-containment refueling water storage tank. Without the normal residual heat removal system operation, it takes approximately three hours before the steaming to containment takes place. This provides ample time to recover the startup feedwater pumps to remove the decay heat via the secondary side and avoid steaming from the in-containment refueling water storage tank.

The in-containment refueling water storage tank cooling by means of the normal residual heat removal system is not credited in the PRA because it does not impact core damage frequency.

References:

440.223-1 WCAP-13793, "AP600 System / Event Matrix," June 1994.

SSAR Revision: NONE

Question 440.238

Table 9.2.2-2 of the SSAR shows the loads on the CCW system in different modes of plant operations. Basically, two CCW pumps are needed in all modes, except normal operation. Provide the following information:

a. During an accident, the plant is shutdown. Shouldn't two pumps instead of one be needed in the PRA analysis? What are the loads listed in the table that are not needed during a transient or accident? What is the guidance to the operators in shedding the loads?

b. For accidents during shutdown conditions, do you use 1 out of 2 success criteria for the CCW system? Again, what are the loads that need to be removed? What is the guidance to the operator?

Response:

a. As stated in SSAR Subsection 9.2.2.3.2, two component cooling water heat exchangers provide redundant cooling for normal operation heat loads. Both heat exchangers are required to achieve the design basis cooldown rate; however, an extended cooldown can be achieved with one heat exchanger in operation. Following an accident, one train of the normal residual heat removal system (one pump and heat exchanger) is adequate to provide core cooling to prevent core damage. One train of component cooling water is sufficient to support the normal residual heat removal system decay heat removal.

   The accident that leads to shutdown results in the generation of the safeguards actuation (S) signal. The S signal will trip the reactor coolant pumps and actuate containment isolation. This isolation will automatically shed the reactor coolant pump cooling loads, chemical and volume control system letdown heat exchanger load and reactor coolant drain tank heat exchanger load. Since none of the component cooling water heat loads are safety-related, none need be supported by component cooling water after an accident. It is desirable to keep the remaining heat loads on the component cooling water after containment isolation; especially normal residual heat removal, spent fuel pit cooling, compressed air system coolers, sample coolers and HVAC system chillers. None of the heat loads need be removed from the component cooling water after an accident.

   It is appropriate that the PRA analysis be based upon operation of one train of component cooling water.

b. PRA analysis for accidents during shutdown uses 1 out of 2 success criteria. None of the heat loads have to be removed from the component cooling system.

SSAR Revision: NONE

PRA Revision: NONE

Question 460.4

Provide the following information regarding gaseous radwaste management systems (Section 11.3):

a. A description of release points for airborne effluents (plant vent and turbine building vent). The description should include information on the height of the release point above grade, its height above and relative location to adjacent structures, expected temperature of the gaseous effluents, flow rate and size and shape of the flow orifice (note that these parameters are required in conjunction with plant-specific parameters to determine plant-specific atmospheric dispersion factors).

b. A demonstration of compliance with Branch Technical Position (BTP) ETSB 11.5 "Postulated Radioactive Releases due to a Waste Gas System Leak or Failure."

c. A discussion of compliance with GDC 3 as it relates to providing protection to gaseous waste handling and treatment systems from the effects of an explosive mixture of hydrogen and oxygen. The discussion should include the provisions incorporated in the AP600 design to control releases due to hydrogen explosions in the gaseous waste management system. Additionally, it should include the type, number and locations of gas analyzers provided in the design of the gaseous waste management system (for response guidance, see Acceptance Criterion II.B.6 of Section 11.3 of the SRP).

d. A discussion of compliance with GDC 60 as it relates to control of releases of radioactive materials to the environment. The discussion should refer to Regulatory Guide (RG) 1.140 to be consistent with Acceptance Criterion II.6.a of Section 11.3 of the SRP (note that reference to the subject guide in Section 9.4 of the SSAR alone is not sufficient). As a minimum, provide a cross reference with Section 9.4 and state clearly whether the design complies with the guide or not).

e. A discussion of compliance with GDC 61 as it relates to radioactivity control in gaseous waste management systems and ventilation systems associated with fuel storage and handling areas.

Response:

a. The plant vent is located along the south-east wall of the containment shield building, as shown in SSAR Figure 1.2-11. SSAR Figure 1.2-11 also shows the height of adjacent structures to the plant vent, including the roof of the shield building at elevation 307'-6", the roof of the fuel handling building at elevation 180'-0", and the auxiliary building at elevation 160'-6". The plant vent has a rectangular cross section approximately 7 feet square (SSAR Figure 1.2-11). The top of the plant vent is approximately at elevation 250'-0" (Q450.5) and is about 150 feet above the grade elevation of 100'-0", which is shown in SSAR Figure 1.2-12.

   A summary follows of the systems, airflow rates, and the normal operating temperature range of the connections to the plant vent of systems which handle radioactive gas or air. The HVAC exhaust airflow rates were compiled from data provided in SSAR Tables 9.4.1-1, 9.4.3-1, 9.4.7-1, 9.4.8-1, and 9.4.11-1. The temperature ranges of the exhaust air from various plant rooms are provided in SSAR Section 9.4.

System	Nominal Design Airflow Rate (scfm)	Maximum Temperature Range (°F)[1]
1. Radiologically Controlled Area Ventilation System	84,000[2]	50-130
~~2. Nuclear Island Nonradioactive Ventilation System~~	~~4,800~~	~~67-73~~
2 ~~3~~. Containment Air Filtration System	4,000/8,000[3]	70-122 ~~140~~[4]
3 ~~4~~. Solid Radwaste Building Ventilation System	20,000 ~~36,000~~	50-130
4 ~~5~~. Health Physics and Hot Machine Shop HVAC System	12,000	65-85
~~5~~ ~~6~~. Gaseous Radwaste System	0.5 ~~0.01~~[5]	--

The turbine vent for the combined discharge of the condenser air removal system and the gland seal system is located on top of the turbine building ~~in the general area near the vacuum degasifier removal hatch shown in Figure 1.2-55~~ and terminates at about elevation 235'-0", 8 to 10 feet above the roof. The exhaust ~~exit pipe~~ is approximately 18 inches in diameter, with either an inverted "J" discharge oriented vertically downward or a cut at 45 degrees oriented vertically upward. The gaseous effluents discharged will vary with the operation of the plant and ambient conditions, but they are expected to have the following approximate properties:

Condenser air removal system:

Flow	40 cfm
Temperature	100°F

[1] This temperature range is conservative; multiple compartments at different temperatures will tend to reduce the range.

[2] Assumes a maximum airflow rate from the fuel handling area associated with refueling operations; normal operation will have a lower flow.

[3] Operates intermittently. One or two redundant systems may be operated.

[4] Includes 20°F estimated temperature rise due to ~~through~~ ~~exhaust~~ fan motor heat.

[5] Intermittent operation.

Gland seal system	
Flow	1200 cfm
Temperature	145°F

b. As stated in SSAR Subsection 15.7.1, the SRP no longer includes this event as part of the review process and no analysis is provided in the SSAR.

An analysis has been performed in keeping with the guidance of Branch Technical Position ETSB 11-5. The analytical assumptions are as follows:

1. The accident consists of a failure of the gaseous waste management system in such a way that the charcoal delay beds are bypassed and activity is released directly to the environment. The duration of this release is one hour.

2. The site boundary atmospheric dispersion factor is as given in Table 15A-5 (1.0E-3 sec/m^3).

3. The nuclide dose conversion factors are as given in Table 15A-4.

4. The primary coolant source term is that associated with operation at the design basis fuel defect level of 0.25 percent. This source term is provided in Table 11.1-2. Consistent with ETSB 11-5, the beyond-design-basis case of one percent fuel defects is also considered. With one percent fuel defects, the source term is four times that associated with operation with 0.25 percent fuel defects.

5. The full letdown flow of 100 gpm is being processed by the gas stripper, and the stripped gases are released.

6. There is a 30 minute decay period to address the time for the release to reach the exclusion boundary.

7. The normal release of noble gas activity from the gaseous radwaste system is added to the calculated accident releases.

The resulting activity releases follow for the case assuming the design fuel defect level of 0.25 percent:

Isotope	Release (Ci)
Kr-85m	~~1.3E1~~ 1.2E1
Kr-85	4.5E1
Kr-87	~~7.2E0~~ 5.5E0
Kr-88	~~2.2E1~~ 1.9E1
Xe-131m	1.2E1
Xe-133m	1.1E2
Xe-133	1.8E3
Xe-135m	~~1.9E0~~ 5.0E-1
Xe-135	~~5.2E1~~ 5.0E1
Xe-138	~~3.4E0~~ 7.9E-1

For the case assuming 0.25 percent fuel defects (design basis fuel defect level), the whole body dose at the site boundary is 0.0224 rem which is below the 0.5 rem dose limit identified in ETSB 11-5.

For the case assuming the beyond-design-basis case of 1.0 percent fuel defects, the above releases would be increased by a factor of four and the whole body dose at the site boundary is 0.09 rem which is below the 0.5 rem dose limit identified in ETSB 11-5.

c. The AP600 gaseous radwaste system (WGS) normally contains ~~essentially 100 percent~~ a mixture of hydrogen and nitrogen gases, bearing small quantities of radioactive gases. Depending on the plant operation, the mixture will be mostly nitrogen during purging and mostly hydrogen when degassing reactor coolant. The WGS is designed to prevent an explosive mixture of hydrogen and oxygen.

Provisions made to prevent a flammable or explosive mixture, as discussed in SSAR section 11.3.1.2.3.1, include the following:

- The WGS operates at a pressure slightly above atmospheric, which prevents the ~~inleakage~~ ingress of oxygen, which could occur in a sub-atmospheric system.
- A continuous purge flow of nitrogen is provided at the outlet of the WGS in order to prevent back-leakage of air through the discharge check valves.
- Redundant oxygen analyzers are provided for continous sampling in a side stream taken off the process flow path. These analyzers create alarm messages ~~annunciate~~ both locally and in the main control room upon high oxygen level. Setpoints are specified ~~in accordance with allowing~~ to allow adequate time for operator action. The setpoint for alarm is adjustable, but is generally at about 1.25% concentration. This is approximately one fourth of the lower flammability limit for mixtures of hydrogen and oxygen. The side stream is returned to the process flow after sampling.
- A hydrogen analyzer is provided for direct measurement of hydrogen concentration in the sampling side stream. No specific alarm setpoint is assigned to this analyzer because of the broad range of expected hydrogen concentrations. By using the hydrogen analyzer reading and a flammability chart, operator can assess the flammability potential of the gases during an upset situation which permits oxygen into the system.
- A hydrogen monitor is provided to sample the ambient environment of the charcoal bed vault. This analyzer creates alarm messages both locally and in the main control room upon high hydrogen level. The setpoint for alarm is adjustable, but is generally at about 1% concentration. This is approximately one fourth of the lower flammability limit for mixtures of hydrogen and oxygen.
- The gaseous radwaste system is of welded construction. The piping and components are metallic conductors. The entire system is electrically at the same potential which eliminates the buildup of static electricity and sparking.
- The gaseous radwaste system throttling and isolation valves are packless metal diaphram type which eliminate leakage in or out of the system through the stem seals.

There is no normal source of oxygen into the system so automatic isolation of the oxygen source and automatic injection of nitrogen for dilution is not required.

These provisions satisfy GDC 3 and Acceptance Criterion II.B.6 of Section 11.3 of the SRP.

d. A brief discussion of compliance with GDC 60 is provided in SSAR Section 3.1. Relative to the gaseous radwaste system, GDC 60 specifies that means should be included to suitably control the release of radioactive materials in gaseous effluents and that sufficient holdup capacity shall be provided, particularly where unfavorable site environmental conditions can be expected to impose limitations on the release of such effluents to the environment.

Suitable control of releases from the gaseous radwaste system is provided by the radiation monitoring system (discussed in SSAR Section 11.5), which automatically terminates releases from the gaseous radwaste system when a high-activity setpoint is exceeded in the system discharge line.

Sufficient holdup time is provided by the gaseous radwaste system since the system can be isolated at any time ~~deemed necessary~~. The system is not normally in operation but ~~is~~ ~~will be~~ operated as necessary when reductions in the reactor coolant system noble gas inventory are made. ~~Additionally, i~~ It is not expected that any alteration in the system operation will be necessary because of adverse meteorological conditions since anticipated operation in the system provides 870 days holdup of xenon isotopes and 48 days holdup of krypton isotopes. After this level of radioactive decay, all nuclides except for Kr-85 would be reduced to extremely small amounts, and the release of Kr-85 is not of consequence.

In addition to the gaseous radwaste system, the exhaust air from several ventilation systems also may contain airborne radioactivity. Provisions to control radioactive releases from these systems to the environment are described below.

1. The radiologically controlled area ventilation system (VAS) serves the fuel handling area (which encloses the spent fuel pool), radiologically controlled areas of the auxiliary building and the annex~~-H~~ building. These areas are normally maintained at a slightly negative ambient air pressure with respect to adjacent clean plant areas and the environment to provide controlled release and monitoring of airborne effluents at the plant vent.

   Compliance with 10 CFR 20 effluent ~~maximum permissible~~ concentration ~~(MPC)~~ limits and 10 CFR 50 Appendix I dose guidelines for offsite releases has been conservatively evaluated assuming that ~~the all~~ exhaust air discharged by the VAS to the plant vent is unfiltered. Analysis indicates that no HEPA or charcoal filtration is required in order to keep normal plant releases within the specified limits. Therefore, the criteria set forth in RG 1.140 do not specifically apply to the VAS exhaust air system. As an enhancement to the system design, the VAS exhaust system does include local filtration of exhaust air from specific plant areas such as the radiation chemistry laboratory, sampling room and effluent holdup tanks. These filtration systems add design margin with respect to the normal calculated releases since no filtration credit, based on RG 1.140 design criteria, is assumed. See SSAR Appendix 1A for a discussion of conformance with Regulatory Guides.

   The exhaust air upstream of the plant vent is monitored for airborne radioactivity (discussed in SSAR Section 11.5). In the event that abnormal airborne radioactivity is detected, the exhaust and supply air is automatically isolated to terminate unfiltered releases to the plant vent. As discussed in SSAR Subsection

9.4.2.3, the exhaust ducts from the fuel handling area and auxiliary building areas that have the greatest potential for a significant release of airborne radioactivity are sized to hold up the exhaust air, allowing the isolation dampers to close before the abnormal airborne radioactivity is exhausted. The exhaust from the isolated high radiation area is then realigned to the containment air filtration system (VFS). The VFS exhaust filters and fans operate to maintain a slightly negative air pressure within the isolated area with respect to the surrounding clean plant areas to prevent unfiltered releases to the environment. The VFS exhaust air is HEPA and charcoal filtered before it is discharged from the plant vent.

2. The containment air filtration system provides HEPA and charcoal filtration of air exhausted from the containment during normal plant operation. Compliance with 10 CFR 20 effluent ~~maximum permissible~~ concentration limits and 10 CFR 50 Appendix I dose guidelines for offsite releases has been evaluated assuming that the exhaust filters remove 99 percent of the particulate contaminants and 90 percent of the radioiodides, based on the guidance provided in RG 1.140. The containment exhaust filters meet RG 1.140 guidelines to the extent practical. See SSAR Appendix 1A for a discussion of conformance with Regulatory Guides. Most of the design standards referenced by RG 1.140 have been revised since the issuance of Revision 1 of the Regulatory Guide in October 1979. ~~It is assumed that t~~ The filtration systems ~~that~~ are designed in accordance with the updated design standards such as ASME N509-1989 and ASME N510-1989 and will provide decontamination efficiencies ~~that are~~ comparable to filtration systems designed in accordance with previous standards. The SSAR also includes the following key performance requirements, based on RG 1.140 guidelines, as a basis for assuming RG 1.140 decontamination efficiencies:

- SSAR Table 9.47-1 states that the charcoal absorber provides an overall bed depth of 4 inches with an air residence time of 0.5 second. This is consistent with RG 1.140, Position C.3.g, and Table 2 to provide an air residence time rated for a 90 percent decontamination efficiency.

- SSAR Subsection 9.4.7.2.1 states that an electric heater is provided to maintain the relative humidity of the incoming air so that it does not exceed 70 percent relative humidity. This is consistent with RG 1.140, Position C.3.a.

- SSAR Subsection 9.4.7.4 states that HEPA filters are individually tested to verify an efficiency of at least 99.97 percent when tested with monodisperse 0.3 micron diameter DOP particles. This is consistent with RG 1.140, Position C.3.b, which references Military Standard Mil-F-51068C. (It should be noted that the current standard, 51068F, no longer requires DOP testing at 20 percent rated flow for HEPA filters rated at 1000 cfm.)

- SSAR Subsection 9.4.7.4 states that (new) charcoal adsorbent is batch tested in accordance with ASME N509. ASME N509-1989, Section 5.2.3.2, provides adsorbent requirements for non-ESF absorbers by referencing ASME/ANSI AG-1-1988, Section FF, which provides qualification and batch test requirements for new bulk charcoal. It is assumed that charcoal manufactured in accordance with ASME/ANSI AG-1-1988 will be equivalent to charcoal meeting the criteria set forth in RG 1.140, Table 1.

- SSAR Subsection 9.4.7.4 states that both the HEPA filters and charcoal absorbers will be field-tested to verify that the bypass leakage rate does not exceed 0.05 percent in accordance with ASME N510-1989. The bypass leakage rate of 0.05percent is consistent with RG 1.140, Positions C.5.c and C.5.d.

- SSAR Subsection 9.4.7.4 also states that periodic testing in accordance with ASME N510-1989 will be performed. This standard encompasses several key field-testing requirements that are also referenced in RG 1.140, including the following:

  - Table 1 of ASME N510-1989 requires that representative samples of used charcoal adsorbent be periodically tested after every 720 hours of system operation (and adjustment made based on operating history) or when inadvertently exposed to organic solvents. This should be comparable to RG 1.140, Table 2 criteria, which recommend that tests be conducted at least once every 18 months or when exposed to fumes, chemicals, or foreign materials that could adversely affect the charcoal. The objective is to have an effective testing schedule that allows ~~ensures that~~ the charcoal to be ~~is~~ tested and replaced when it does not meet the required efficiency.

  - ASME N510-1989, Section 8.6.2, requires that airflow distribution tests across HEPA filters and charcoal absorbers meet an acceptance criterion of plus or minus 20 percent of the design airflow velocity. This is consistent with RG 1.140, Position C.5.b.

- SSAR Subsection 9.4.7.4 states that the exhaust filtration units are designed in accordance with ASME N509-1989. Design compliance with ASME N509-1989 should be comparable to ANSI N509-1976, which was used as a reference for the guidelines in RG 1.140.

Compliance with the above criteria should provide assurance that the airborne effluents discharged from the containment will be controlled by filtration consistent with the guidance provided in RG 1.140.

In the event of abnormal containment airborne radioactivity, the containment high-range radiation monitors will automatically isolate the VFS supply and exhaust air containment isolation valves. Additionally, dedicated radiation monitors in the VFS exhaust lines will also provide an alarm signal if abnormal releases to the environment are detected in the exhaust lines.

3. The solid radwaste building ventilation system (VRS) maintains the solid radwaste building at a slightly negative ambient air pressure with respect to the surrounding clean plant areas to provide controlled release and monitoring of airborne effluents at the plant vent. The airborne radiological releases from this system are based on a conservative assumption that the ~~all~~ exhaust air is unfiltered since this area normally contributes a small fraction of the normal overall airborne releases. Analysis indicates that no HEPA or charcoal filtration is required in order to keep normal plant releases within 10 CFR 20 effluent ~~maximum permissible~~ concentration limits and 10 CFR 50 Appendix I dose guidelines. However, as noted in SSAR Subsection 9.4.8, the exhaust air from this area is provided with HEPA filtration in accordance with RG 1.140, which adds design margin for the normal calculated releases since no filtration credit, based on RG 1.140 design criteria, is assumed.

If abnormal airborne radioactivity is detected in the exhaust air, an alarm in the MCR is initiated for operator action.

4. The health physics and hot machine shop HVAC (VHS) maintains the areas that it serves at a slightly negative ambient air pressure with respect to the surrounding clean plant areas to provide controlled release and monitoring of airborne effluents at the plant vent. The airborne radiological releases from this system are based on a conservative assumption that the ~~all~~ exhaust air is unfiltered since this area normally contributes a small fraction of the normal overall airborne releases. Analysis indicates that no HEPA or charcoal filtration is required in order to keep normal plant releases within 10 CFR 20 maximum permissible concentration limits and 10 CFR 50 Appendix I dose guidelines. However, as noted in SSAR Subsection 9.4.11, the exhaust air from this area is provided with HEPA filtration in accordance with RG 1.140, which adds design margin for the normal calculated releases since no filtration credit, based on RG 1.140 design criteria, is assumed.

   If that abnormal airborne radioactivity is detected in the exhaust air, an alarm in the MCR is initiated for operator action.

e. A brief discussion of compliance with GDC 61 is provided in SSAR Subsection 3.1.6. The fuel storage and handling areas for the AP600 include the fuel handling area of the auxiliary building, which encloses the spent fuel pool, and the containment building that encloses the reactor cavity. Based on the calculated radiological releases resulting from a design basis fuel handling accident (SSAR Subsection 15.7.4) in either area, there is no need to provide safety-related isolation or filtration systems to maintain plant safety.

   As discussed in item (d), the ventilation systems serving these plant areas incorporate specific design features to mitigate the potential release of abnormal (non-DBA) airborne radioactivity from these areas. In addition to automatic isolation of the fuel handling area or containment purge valves on a high radiation signal, the isolation dampers or valves can be manually controlled from the main control room ~~to verify system operability,~~ as shown in SSAR Figures 9.4.3-1 (Sheet 4 of 8) and 9.4.7-1. The fuel handling area isolation dampers and containment isolation valves are provided with remote position indication to verify proper damper blade or valve disk position during isolation. During abnormal airborne radiological conditions, the containment purge valves can be manually opened to override a high ~~low~~ radiation signal, through administrative procedures, to allow cleanup of the containment atmosphere (SSAR Subsection 9.4.7.2.4).

   See SSAR Figures 9.4.3-1 (Sheets 2 and 4) and 9.4.7-1 (Sheets 1 and 2). The supply and exhaust lines that penetrate the fuel handling and containment areas include isolation subsystems. The VFS maintains the fuel handling area at a slightly negative air pressure during isolation, is redundant (SSAR Subsection 9.4.7.2.1) and can be manually connected to the onsite diesel generators if there is a loss of offsite power (SSAR Subsection 9.4.7.2.4). As shown in SSAR Subsections 9.4.3.2.2 and 9.4.7.2.2, the isolation dampers and isolation valves are controlled by pneumatic operators that fail-~~safe~~ in a closed position on loss of electric power or air pressure.

   SSAR Subsection 9.4.7.4 states that the VFS exhaust air filtration units are designed and tested in accordance with ASME N509 and N510. ASME N509, Table 4-2, provides instrumentation necessary for the periodic inspection and verification of system airflow rates, air temperatures, and filter pressure drops.

SSAR Revision: NONE

Question 460.20

There is no systematic discussion of how the liquid, gaseous and solid waste management systems meet each one of the guidelines of RG 1.143. Provide an item-by-item demonstration of compliance with RG 1.143 for all of the radwaste management systems.

Response:

Appendix 1A of the SSAR provides a summary of the extent of compliance to the regulatory positions (Section C) of Reg. Guide 1.143, Rev. 1, 10/79 - "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants". Supplementary information to demonstrate compliance is provided below. Each RG 1.143 item is identified by section letter, C, and paragraph number.

C.1.1.1 Components in the liquid radwaste systems are designed and tested to the requirements set forth in the codes and standards listed in Table 1 of RG 1.143. Equipment classifications and design codes are listed in SSAR Table 3.2-3. Pressure vessels are designed and built according to ASME, Section VIII, Div. 1. Atmospheric tanks are per API 650 and heat exchangers to ASME Section VIII, Div.1 and TEMA (for shell and tube). Piping and valves are per ANSI B31.1 except the containment penetrations and isolation valves are per ASME Section III, Class 2. Pumps are according to manufacturer's standards.

C.1.1.2 Materials, except elastomers for gaskets, seals, seats, diaphrams and packing, are provided in accordance with the ASME Code Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ANSI B31.1. Pump materials are provided according to manufacturer's standards.

C.1.1.3 Please refer to the response to RAI 460.6, Rev. 1, which addresses the location of components and the seismic design of the buildings which contain radioactive waste. The auxiliary building that contains the liquid radwaste system tanks is designed to Seismic Category I criteria. The Seismic Category I structure will retain the maximum liquid inventory of the tanks. The Seismic Category I criteria exceed the OBE required by regulatory position C.5 of Reg. Guide 1.143.

C.1.1.4 Components in the liquid radwaste systems are non-seismic. They are not required to be designed for seismic loads.

C.1.2.1 Atmospheric tanks in the liquid radwaste system have level sensors, transmitters and alarms. Local alarm is not provided because the tanks are located in shielded areas which are not normally occupied by people.

C.1.2.2 Tank overflows, drains and sample lines which may contain radioactive water are routed to the liquid radwaste system for processing.

C.1.2.3 Please refer to the response to RAI 460.6, Rev. 1, which addresses the provisions in the buildings which contain radioactive waste to contain any spills.

C.1.2.4 Please refer to the responses to RAI 460.6, Rev. 1, which addresses the provisions in the building which contains radioactive waste to contain any spills and RAI 460.12 which addresses the ventilation arrangement to prevent contamination of clean areas.

C.1.2.5 This guideline does not apply because the liquid radwaste system has no outdoor tanks.

C.2.1.1 Components in the gaseous radwaste systems are designed and tested to the requirements set forth in the codes and standards listed in Table 1 of RG 1.143. Heat exchangers are designed and built according to ASME, Section VIII, Div. 1 and TEMA (for shell and tube). Piping and valves are per ANSI B31.1. Pumps are according to manufacturer's standards.

C.2.1.2 Materials, except elastomers for gaskets, seals, seats, diaphrams and packing, are provided in accordance with the ASME Code Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ANSI B31.1. Pump materials are provided according to manufacturer's standards.

C.2.1.3 Please refer to the responses to RAI 460.6, Rev. 1, which addresses the location of components and the seismic design of the auxiliary building which contains the gaseous radwaste system. The response to RAI 460.6, Rev. 1, also addresses the seismic design of the charcoal delay beds supports.

C.3.1 The regulatory guidance applies to the AP600 solid waste processing system except for components and subsystems used to solidify or concentrate liquid waste. The AP600 solid waste processing system does not have these components/subsystems. These functions are provided by contractors who process chemical wastes using mobile systems.

C.3.1.1 The solid radwaste system is designed and tested to the requirements set forth in the codes and standards listed in Table 1 of RG 1.143. The spent resin tanks are designed and tested in accordance with ASME Code, Section VIII, Div. 1. Piping and valves are designed and tested according to ANSI B31.1. The pumps are designed to manufacturers' standards and tested in accordance with the Hydraulic Institute standards.

C.3.1.2 Materials, except elastomers for gaskets, seals, seats, diaphrams and packing, are provided in accordance with the ASME Code Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ANSI B31.1. Pump materials are provided according to manufacturer's standards.

C.3.1.3 Please refer to the response to RAI 460.6, Rev. 1, which addresses the location of components and the seismic design of the auxiliary building which contains radioactive waste. The Seismic Category I structure will retain the maximum liquid and spent resin inventory of the spent resin tanks. The Seismic Category I criteria exceed the OBE required by regulatory position C.5 of Reg. Guide 1.143.

C.3.1.4 The equipment and components used to collect, process and store solid radwaste are non-seismic as permitted by this paragraph.

C.4.1 SSAR section 12, "Radiation Protection", discusses the measures taken to maintain the radiation exposure to personnel as low as reasonably acheivable.

C.4.2 The quality assurance program applied to the liquid radwaste system meets the requirements of ASME NQA-1-1989 Edition through NQA-1b-1991 Addenda. This quality program meets the requirements of Reg. Guide 1.143.

C.4.3 Pressure containing components in the radwaste systems are of welded construction to the maximum practical extent. Flanged joints and quick connect fittings are used only where maintenance or operational requirements indicate that they are preferable. Screwed connections are not used except for some instrumentation and vents and drains where welded construction is not suitable. Process lines are 1" or larger. Socket welding is used for line sizes 2 1/2" and smaller. Butt welds are used in process lines larger than 2 1/2". Non-consumable backing rings are not used in process piping welds. Process pipe welding is performed as required by ANSI B31.1. Component welding is performed as required by the applicable construction code.

C.4.4 Hydrostatic testing is performed as required by the applicable construction codes.

C.4.5 In-service testing of the containment penetrations and isolation valves is performed as described in SSAR section 3.9.6. Other tests, on non-safety equipment, are performed on an item by item basis as judged necessary to confirm proper operation of the systems.

C.5.1.1 The operating basis earthquake has been eliminated from the AP600 design basis. Seismic design of the gaseous radwaste system is addressed in the response to RAI 460.6, Rev. 1.

C.5.1.2 Regulatory Guide 1.143 endorses AISC-1969, which has been superseded by AISC-1989 and ACI 318-77, which has been superseded by ACI 318-89. AP600 uses the latest version of the industry standards. These versions are not endorsed by a regulatory guide but their use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.143.

C.5.1.3 The construction and inspection requirements of AISC-1989 and ACI 318-89 are followed as appropriate.

C.5.2 and subparagraphs C.5.2.1 through C5.2.6 Those portions of the radwaste systems which require seismic design by Regulatory Guide 1.143 are housed in the auxiliary building which is Seismic Category I. Certain portions which do not require seismic design (e.g. solid radwaste storage) are housed in the radwaste building which is non-seismic.

C.5.3 Shield structures, if used, will comply with Regulatory Guide 1.143, position C.5.2.

C.6 The quality assurance program, as outlined in Chapter 17 of the SSAR and applied to the radwaste systems, meets the requirements of ASME NQA-1-1989 Edition through NQA-1b-1991 Addenda. This quality program meets the requirements of Reg. Guide 1.143, position C.6.

SSAR Revision: None
PRA Revision: None

Question 460.21

Compliance of liquid and gaseous effluent concentrations in unrestricted areas with 10 CFR Part 20 limits is not based on 1% FF or annual average. Tables 11.2-8 and 11.3-4 of the SSAR should be revised based on 1% FF and annual average effluent concentrations of radionuclides in unrestricted areas.

Response:

The determination of compliance of maximum liquid and gaseous effluent concentrations in unrestricted areas with 10 CFR Part 20 limits that is provided in the SSAR is based on the design basis fuel defect level of 0.25 percent and on the annual average atmospheric dispersion factor.

Although the AP600 has as a design basis a maximum fuel defect level of 0.25 percent, Tables 11.2-8 and 11.3-4 will be revised to include consideration of operation with a fuel defect level of 1.0 percent. The 1.0 percent fuel defect level is a beyond-design-basis condition but is consistent with the guidance of Regulatory Guide 1.70, Revision 3 and with Sections 11.2 and 11.3 of the Standard Review Plan.

Revision of SSAR Tables 11.2-8 and 11.3-4 to reflect the use of 1.0 percent fuel defects will be provided in SSAR Revision 2.

SSAR Revision: NONE

Question 460.22

The waste gas processing system failure analysis is not based on applicable BTP assumptions. The system should be reanalyzed in accordance with the assumptions of BTP ETSB 11-5.

Response:

Based on the NRC comments provided in their letter dated May 12, 1994, the assumptions from BTP ETSB 11-5 that the NRC has requested be addressed are

1. That a 1.0 percent fuel defect level be assumed instead of 0.25 percent,

2. That the duration of releases be made two hours instead of the one hour that was used, and

3. That the contribution associated with normal releases be included (to reflect potential release of activity from the charcoal delay bed).

The analysis has been revised to consider both the case with the AP600 design basis fuel defect level of 0.25 percent and the beyond-design-basis case of 1.0 percent fuel defects. The 1.0 percent fuel defect level is consistent with the guidance of BTP ETSB 11-5 but inconsistent with the AP600 Tech Spec limits for primary coolant activity levels and is also inconsistent with the source terms used for the design basis accidents addressed in Chapter 15.

The duration of the accident has been maintained at one hour consistent with the guidance of BTP ETSB 11-5. While BTP ETSB 11-5 extends the duration of the accident to two hours to address the time required to either reduce reactor power level or to bring a second train of the gaseous radwaste system into operation, this is not applicable to the AP600. The implication of the assumption that releases continue for a second hour is that the plant is expected to operate with a constant purge of the volume control tank or with gas stripping of the letdown flow. The AP600 does not operate in this manner. The only time during AP600 power operations that gas stripping of primary coolant is anticipated is when the coolant is diverted to the effluent holdup tank (normally as a result of primary coolant dilution operations to reduce boron concentrations). With the failure of the gaseous radwaste system the plant would be operated in the normal mode but without performing boron dilution.

The revised analysis includes consideration of the atmospheric pathway releases associated with normal operations. There is no significant impact on the calculated doses from this contribution.

The original analysis of releases and doses took no credit for decay of the activity. The reanalysis, consistent with the guidance of ETSB 11-5, takes credit for 30 minutes of decay.

Revision 1 of the response to RAI 460.4(b) provides the revised analysis.

SSAR Revision: NONE

Question 460.25

The GALE code should be rerun with the revised inputs for liquid waste processing and waste gas processing. The GALE output should be checked for secondary concentrations of iodines and other isotopes.

Response:

The GALE code will be rerun with results from the reanalysis to be provided in SSAR Revision 2.

SSAR Revision: NONE

Question 480.64

This question pertains to Westinghouse's statement of conformance to paragraph 6.1.1 of the Standard Review Plan, "Engineered Safety Features Materials," Criteria B.1, Regulatory Guide (RG) 1.7, Paragraph C.5 that is identified on page 6-4 of Revision 1 to WCAP-13054, "AP600 Compliance with SRP Acceptance Criteria."

The WCAP states that "... the radiolysis source term for the AP600 is based on release of gap inventories."

The staff interprets this statement to indicate that the radiolysis source term is based on only the release of gap inventories. This position appears to be a significant deviation from the criteria provided in RG 1.7. To assess the degree of deviation, provide the total hydrogen generated due to radiolysis as a function of time using the AP600 assumptions and the assumptions of RG 1.7.

Response:

The assumption that only the gap activity is released to the sump solution is a departure from the RG 1.7 assumption that there is a release of core activity consistent with RG 1.4. However, RG 1.7 is internally inconsistent since, although it specifies a core melt type of release as defined in RG 1.4, it also specifies a small fraction of the zirconium reacting with water for the production of hydrogen. In order to experience the core melt release of activity there would have to be a zirconium-water reaction involving a large fraction of the fuel cladding. If it is assumed that there is a large fraction of fuel cladding reacting with water to produce hydrogen, the scenario no longer is the design basis LOCA hydrogen production following a LOCA but is the severe accident analysis type of hydrogen production event.

Figure 480.64-1 provides total hydrogen generated due to radiolysis as a function of time using both the AP600 assumptions which include gap releases but no core melting and the assumptions of RG 1.7 which include activity releases from the core consistent with core melt.

The impact of the increase in the total hydrogen production associated with using the RG 1.7 assumptions versus those assumptions used in the AP600 analysis reported in the SSAR is a reduction in the time at which 3.5 volume percent hydrogen is reached inside containment from 6.5 days after the accident to 5.25 days. Subsection 6.2.4 of the SSAR states that a recombiner needs to be actuated by six days into the accident (rounded down from the 6.5 days calculated) to assure that a combustible mixture is not reached in the containment. If the RG 1.7 assumptions for the radiolysis source term are used, hydrogen recombiner operation would need to be initiated at five days after the accident instead of six days.

The six day period stated in the SSAR for actuation of the recombiners is retained to be consistent with the accident design basis assumptions.

SSAR Revision: NONE

Question 720.277

Address the role of the operator in digital control rooms. The top 10 or 15 failures (dominant contributors) in the AP600 analysis involve I&C failures. Software is supposed to isolate the steam generator during a tube rupture event, but if it fails, will the crew know that they face a steam generator tube rupture, or could the operators misinterpret it as another transient and take actions accordingly? If the digital indications fail, do they fail high, low, or give the last (good) value? Trusting instrumentation could result in the wrong event diagnosis or selection of incorrect actions. Define the role of the operator in terms of the following:

a. Will the RO, SRO, or STA allow the I&C systems to make operating decisions, or is the RO, SRO, or STA expected to intervene following a transient?

b. What kind of instrumentation is available to the operator to allow him to conclude that the I&C systems are working correctly?

c. What kind of instrumentation is available to the operator to assure him that the I&C systems are producing the proper response following an accident (i.e., how the accident is progressing)?

d. How are the operators expected to respond to and diagnose transients induced by I&C failures?

Response:

a. For the AP600, as in current plants, the operator assumes a supervisory role in monitoring alarms and verifying automatic system actuation, initiating protective functions, and performing manual actions as needed. The role of the operator is discussed in SSAR Subsection 18.6.6. The responses to RAIs 620.41, 620.72, 620.74 and 620.78 further discuss the role of the operator. Other RAIs in the 620 series discuss related issues such as the human performance modeling and the man-machine interface (MMI) verification and validation program.

b. The AP600 instrumentation and control architecture is discussed in Chapter 7 of the AP600 SSAR. Safety-related operator displays are provided by the qualified data processing system which is part of the safety-related protection and safety monitoring system. Nonsafety-related operator displays are provided by the nonsafety-related data display and processing system. The data display and processing system also includes the nonsafety-related plant alarm system. In addition, diverse displays are provided as part of the nonsafety-related diverse actuation system. These display the plant state to the operator, the status of automatic actions taken by the instrumentation and control systems, and alarm if limits have been exceeded. In addition, the instrumentation and control systems monitor their operation and report abnormal operation to the plant operators.

c. Refer to the response to item b, above.

d. Refer to the response to item a, above.

AP600

SSAR Response: NONE

PRA Response: NONE

Question 920.3

Section 9.5.3 of the SSAR states that security lighting is site-specific and will be described in the combined license application. Section 8.4 of Chapter 11 of the EPRI ALWR Requirements Document for passive plant designs provides guidance for standard designs to ensure adequate monitoring capability of security-related areas. Discuss what provisions have been provided in the standard design to address adequate monitoring capability of security-related areas.

Response:

The ALWR Utility Requirements Document does not represent licensing requirements. The buildings and structures for the AP600 are located such that isolation zones and exterior areas within the protected area can be illuminated per the monitoring and observation requirements of 10 CFR 73.55(c)(3), (c)(4), and (h)(4). The security plan is the responsibility of the Combined License applicant.

SSAR Revision:

Revise the first paragraph of SSAR Subsection 9.5.3 as follows:

The plant lighting system includes normal, emergency, and security lighting. The normal lighting provides normal illumination during plant operating, maintenance, and test conditions. The emergency lighting provides illumination in areas where emergency operations are performed upon loss of normal lighting. Security lighting system is site-specific and is described in the combined license ~~applicant~~ application.

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August 3, 1994

Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

ATTENTION: R. W. BORCHARDT

SUBJECT: WESTINGHOUSE RESPONSES TO NRC REQUESTS FOR ADDITIONAL INFORMATION ON THE AP600

Dear Mr. Borchardt:

Enclosed are three copies of the Westinghouse responses to NRC requests for additional information on the AP600 from your letters of April 19, 1994, April 29, 1994, May 2, 1994, May 5, 1994, May 12, 1994, May 16, 1994, May 23, 1994, May 26, 1994, June 8, 1994 and June 27, 1994. In addition, revisions of responses previously submitted are provided.

A listing of the NRC requests for additional information responded to in this letter is contained in Attachment A.

These responses are also provided as electronic files in WordPerfect 5.1 format with Mr. Kenyon's copy.

If you have any questions on this material, please contact Mr. Brian A. McIntyre at 412-374-4334.

Nicholas J. Liparulo, Manager
Nuclear Safety Regulatory And Licensing Activities

/nja

Enclosure

cc: B. A. McIntyre - Westinghouse
T. Kenyon - NRR

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