NUREG-0011
Supplement No. 5

Safety Evaluation Report

related to the operation of
Sequoyah Nuclear Plant,
Units 1 and 2

Docket Nos. 50-327 and 50-328

Tennessee Valley Authority

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

June 1981

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

On September 17, 1980, we issued TVA a license to operate Sequoyah Unit 1 at full power in accordance with the facility license and Technical Specifications. This was based on our Safety Evaluation Report and Supplements 1 through 4 which are applicable to Sequoyah Units 1 and 2. The TMI-2 requirements imposed were specifically approved by the Commission for implementation in new operating licenses. The requirements were derived from NRC's Action Plan (NUREG-0660) and are given in NUREG-0694, "TMI-Related Requirements for New Operating Licenses," as clarified and supplemented by NUREG-0737, "Clarification of TMI Action Plan Requirements," dated November 1980. The ACRS reviewed Sequoyah Units 1 and 2 and reported its findings in a series of letters as described in Supplement Nos. 2 and 4 to the SER. Additional consideration to these matters is given in this supplement. The Committee concluded that the Sequoyah units can be operated safely at full power.

The purpose of this supplement is to update our evaluations on issues identified in the previous SER and supplements that need resolution prior to licensing Unit 2, and to clarify or supplement, as necessary, our evaluations to be consistent with NUREG-0737. Also we have provided in Section 24 a summarization of a recent Sandia National Laboratories study entitled, "Reactor Safety Study Methodology Application Program, Sequoyah #1 PWR Power Plant." Also, Section I.D.1 summarizes the NRC's Region II office report on the Systematic Assessment of Licensee Performance.

The following sections of this supplement are numbered to correspond to identically numbered sections of the safety evaluation report and the earlier supplements. Except where noted, the material herein supplements material in the SER and Supplement Nos. 1, 2, 3, and 4. The following Table 1-1 provides a SSER reference for discussions on TMI-related items for licensing Sequoyah Units 1 and 2.

As we did for Unit 1, we will also impose license conditions on Unit 2 that deal with provisions and actions for a hydrogen control system.

We conclude that Sequoyah Unit 2 may be operated safely at full power in accordance with the facility license and Technical Specifications without undue risk to the health and safety of the general public.

Table 1.1 SSER reference table on NUREG-0694 and -0737 for fuel load and full-power requirements for Sequoyah Units 1 and 2

		Supplements					License conditions	
Item	Shortened title	1	2	3	4	5	Unit 1	Unit 2
I.A.1.1	Shift technical advisor	X	X			X	X	X
I.A.1.2	Shift supervisor responsibilities	X						
I.A.1.3	Shift manning	X	X			X		
I.A.2.1	Immediate upgrade of RO and SRO training and qualifications		X					
I.A.2.3	Administration of training programs		X					
I.A.3.1	Revise scope and criteria for licensing exams		X					
I.B.1	Organization and management criteria	X	X			X		
I.B.1.2	Independent Safety Engineering Group	X	X			X	X	X
I.B.1.4	Licensee onsite operating experience evaluation capacity	X						
I.B.2.2	Resident inspector	X						
I.C.1	Short-term accident and procedure review	X	X			X	X	
I.C.2	Shift and relief turnover procedures	X						
I.C.3	Shift supervisor responsibility	X						
I.C.4	Control room access	X						
I.C.5	Feedback of operating experience	X						

Table 1.1 (continued)

Item	Shortened title	Supplements					License conditions	
		1	2	3	4	5	Unit 1	Unit 2
I.C.6	Verify correct performance of operating activities					X	NR	X
I.C.7	NSSS vendor review of procedures	X	X					
I.C.8	Pilot monitor of selected emergency procedures for NTOLs		X					
I.D.1	Control room design reviews		X			X	X	X
I.G.1	Training during low-power testing	X	X			X	NR	X
II.B.1	Reactor coolant system vents		X			X	X	X
II.B.2	Plant shielding		X			X	X	NR
II.B.3	Postaccident sampling		X				X	X
II.B.4	Training for mitigating core damage	X	X			X		
II.B.7	Analysis hydrogen control	X	X	X	X	X	X	X
II.B.8	Rulemaking proceeding on degraded core accidents		X					
II.D.1 II.D.2	Relief and safety valve test requirements	X	X			X	X	X
II.D.3 II.D.5	Relief and safety valve position indication	X	X					
II.E.1.1	Auxiliary feedwater system evaluation		X			X	X	X
II.E.1.2	Auxiliary feedwater system initiation and flow	X	X				X	NR

Table 1.1 (continued)

Item	Shortened title	Supplements 1	2	3	4	5	License conditions Unit 1	Unit 2
II.E.3.1	Emergency power for pressurizer heaters		X					
II.E.4.1	Dedicated hydrogen penetrations	X	X					
II.E.4.2	Containment isolation dependability		X			X	X	X
II.F.1	Accident monitoring instrumentation							
	a. Noble gas monitoring	X	X				X	X
	b. Iodine particulate sampling	X	X					
	c. Containment high-range monitor	X	X				X	X
	d. Containment pressure	X	X					
	e. Containment water level	X	X					
	f. Containment hydrogen	X	X					
II.F.2	Instrumentation for detection of inadequate core cooling	X	X			X	X	X
II.G.1	Power supplies for pressurizer relief valves, block valves, and level indicators	X						
II.K.1	IE Bulletins							
	5. Review ESF valves	X						
	10. Operability status	X						
	17. Trip per low-level B/S	X						
II.K.2	Orders on plants							
	13. Effect of HPI for small-break LOCA with no aux feed	X				X		
	17. Voiding in RCS					X	C	X
	19. Benchmark analysis seq. AFW flow					X	C	X

Table 1.1 (continued)

Item	Shortened title	Supplements 1	2	3	4	5	License conditions Unit 1	Unit 2
II.K.3	Final recommendations, B&O Task Force							
	1. Auto PORV isolation					X		
	2. Report on PORV failures					X		
	3. Reporting SV and RV failures and challenges					X		
	5. Auto trip of RCPs					X		
	9. PID controller					X		
	10. Applicant's propose anticipatory trip at high power					X		
	11. Justification use of certain PORVs					X		
	12. Conform anticipatory trip					X		
	17. ECCS outages					X		
	25. Power on pump seals					X		
	30. SB LOCA methods					X		
	31. Plant-specific					X	C	X
III.A.1.1	Emergency preparedness, short-term		X			X		
III.A.1.2	Upgrade emergency support facilities	X	X			X	X	X
III.A.2	Emergency preparedness					X	C	X
III.A.3	Upgrade license emergency preparedness	X	X					
III.A.3.3	Communications	X						
III.B.1	NRC approval of overall emergency preparedness	X						
III.B.2	Implementation of NRC and FEMA responsibility		X					
III.D	Worker protection	X				X		
III.D.1.1	Primary coolant outside containment		X			X	NR	X

Table 1.1 (continued)

Item	Shortened title	Supplements					License conditions	
		1	2	3	4	5	Unit 1	Unit 2
III.D.2.4	Offsite dose measurements		X					
III.D.3.3	Inplant I_2 radiation monitoring	X	X					
III.D.3.4	Control room habitability		X					
IV.F.1	Power ascension test		X					

Note: (a) NUREG-0737 combined some of the NUREG-0694 items for clarity.
(b) Some title changes have been made in NUREG-0737 from the previous TMI requirement documents.
(c) NR indicates that a license condition is not required based on justification in SSER #5.
(d) C indicates new license condition required under NUREG-0737 for Unit 1.

2 SITE CHARACTERISTICS

2.2 Nearby Industrial, Transportation, and Military Facilities

In our SER Supplement No. 2 of August 1980, we indicated that TVA would provide an analysis on the probability of an upstream barge collision with the new intake structure (ERCW) in response to a question raised by the ACRS in their review of the Sequoyah operating license (letter dated July 17, 1980 from R. F. Fraley to W. J. Dircks).

On April 6, 1981, TVA submitted an analysis of an upstream barge tow which indicated a random probability of collision with the 68 ft x 118 ft intake structure of 1.6×10^{-5}/year. This was based on three groundings on the Chickamauga Reservoir in 34 years that were judged to be relevant to the risk analysis. TVA also described the features of the site, navigational aids, and barge maneuverability which they indicated would further reduce the probability of collision.

In order to verify independently the applicant's analysis, members of the staff contacted the U.S. Coast Guard and in addition traveled up to the site on the Chickamauga Reservoir on a U.S. Coast Guard tow boat and barge. Based on conversation with the Nashville, Tennessee office of the U.S. Coast Guard, it was indicated that in good weather the cooling towers are visible and that navigation on the reservoir near to the reactor site is not a problem.

The trip on the Coast Guard tow boat on April 8, 1981 indicated to the staff that the river is well marked with channel buoys and lights and that the shore line in the vicinity of the site is quite visible on radar for barge traffic in inclement weather. Normal up-river barge traffic is guided by a day marker and light on the farside of the channel directly opposite the site. These features guide upstream traffic away from the Sequoyah intake structure. The navigation channel in the vicinity of the site is approximately 1100 feet wide. There are prominent features, namely the cooling pond dike, and the skimmer wall dike extending out into the reservoir, which would tend to keep up-river barge traffic from the area of the intake structure, if the tow for some reason violated the "Western Rules of the Road" and approached the reactor site on the wrong side of the river. In addition, the skimmer wall, composed of 12 rock-filled steel caissons 20 feet in diameter, capped with 18 inches of concrete and connected with 30-inch thick concrete skimmer walls would tend to deflect upstream barges before they could impact with the downstream side of the intake structure. (See Figure 1.) In event of loss of power, the river current would move a barge tow towards the opposite side of the lake and away from the intake structure. The reservoir at mile marker 485 is approximately 4200 feet wide (see Figure 2).

The strobe lights on the two cooling towers are visible even in daylight at several miles from the plant, and there are flood lights on the roof of the ERCW which would give an indication of its position in darkness.

Figure 2-1

Shady Grove Shores
Mile 486
Old Penney Cem
Penney Cem
Skull Island
Cem
Gaging station
Microwave Tower
Mile 485
SEQUOYAH NUCLEAR PLANT
(UNDER CONSTRUCTION)
Water
Substation
Locust
Cooling Towers
Meteorological Tower
Hunter Hills
Masterson Cem
Gou Cem
Blue Springs
Chigger Point
Penny Cem
BM LP 104
CHICKAMAUGA RIVER
TENNESSEE
ELEV 683
Orr Slough
Mile 482
BM LP 95
689
Beaty Still Cr
BM AR 78
694
BM AR 699
BM AR 75
856
LAKE
SCALE 1 24 000
7000 FEET
1 KILOMETER
CONTOUR INTERVAL 20 FEET

Figure 2-2

In addition, the ERCW structure is now indicated on the navigation charts for the Chickamauga Reservoir.

In conclusion, it is the staff's qualitative judgment that the presence of the downstream cooling pond dike, and the skimmer wall and skimmer wall dike will tend to reduce the target length of the ERCW from 200 feet to 118 feet. This would reduce the estimated probability of collision to 9.5×10^{-6} per year for random grounding.

Taking into consideration the use of Coast Guard regulations on water travel, barge manueverability, modern navigational aids and the geometric location of the intake structure on the shoreline, the staff judges that the probability for impact into the ERCW is lower than that determined for a random grounding and is estimated to be of the order of 10^{-7}/year. This value is within the guidelines described in Standard Review Plan Section 2.2.3 and is acceptable.

In addition to the collision probability, the ACRS requested information on the ability of the ERCW intake to withstand the effects of barges carrying flammable cargoes including liquified natural gas (LNG).

TVA has investigated the shipment of LNG by water past the Sequoyah site and determined that no transport of this material occurs via barges. The NRC staff concurs in this finding.

2.6 Foundations

2.6.3 Foundations Evaluations

In Section 2.6 of the Safety Evaluation Report Supplement No. 2, it was stated that, except for the ERCW conduit for Unit 2, the staff's concern for settlement of all safety-related structures was resolved. The staff had noted therein that the settlements recorded over a 125-foot length of ERCW conduit were significant enough to require further study. The applicant's position is that the apparent recorded settlements were due to the disturbance of the settlement markers and that no significant settlement of the ERCW lines along the access dike was occurring. However, TVA had continued to monitor the settlement markers in question to resolve this matter, and submitted the results of their monitoring program. The NRC staff inspected the site and personally observed the disturbed settlement markers in October 1980. Additional settlement readings were taken by TVA in February 1981; a survey of the horizontal positions of the settlement markers on the dike was made by TVA to justify their claim that the marker had been damaged by construction activities. The staff has reviewed the settlement data and related survey data furnished by the applicant and has concluded that the ERCW pipes and conduits are not undergoing significant settlements. The settlement monitoring program and the results of the staff's review of the applicant's survey data are briefly discussed below.

Two lines of survey markers are located on each side of the road which overlies the ERCW pipes and conduits. The markers are located at 30-foot or 60-foot intervals from station 21+10 to 23+50. The markers are vertical steel rebars enclosed in a pipe sleeve. Marker Nos. 14S, 15S, 16S, 17S, 18S, and 19S are located on the south side while corresponding marker Nos. 14N, 15N, 16N, 17N, 18N, and 19N are on the north side of the road. The bases of these 12 rebar

markers are embedded in the 3'-0" thick reinforced concrete slab that supports the ERCW pipes and a rockfill dike for a length of about 250 feet. The concrete slab in turn is supported by steel H piles (HP 8x36) that are driven to refusal into rock. The applicant has stated, that the depth of pile penetration in the ERCW piping slab area was to top of rock. Refusal is defined as 5 blows of a 41,300 ft-lb hammer, at listed speed, producing a pile penetration of less than 1 inch.

Six additional markers (Nos. 20S, 20N, 21S, 21N, 22S, and 22N) are located in the rockfill dike between the end of the concrete slab and the plant power block. Markers 21S and 21N are 5 ft from the edge of the slab and markers 22S and 22N are 40 ft from the edge of the slab. Markers 20S and 20N are located between markers 21S and 22S and between 21N and 22N, respectively. With respect to unsuitable foundation soils beneath the dike section of the ERCW lines, it is stated in the FSAR Vol. 12, that the alluvial material at the site of the ERCW access dike was removed to the top of the weathered shale and replaced by crushed rock fill. This seems to be generally true, except beyond the edge of the concrete slab on the shore side where the existing soft clay layer of about 1 to 2-foot thickness does not appear to have been removed, as seen from boring No. SS-94 in Figure Q2.71-6. The addition of markers 20S through 22N listed above was meant to monitor the settlement of the ERCW pipes in this region of the dike where the pile supported slab does not support the pipes.

The staff review of the settlement data obtained by TVA through February 1981 indicates that the settlement markers located in the dike beyond the edge of the concrete slab have not recorded significant settlements and that only four of the 12 markers installed on the 3'-0" thick reinforced concrete slab supported by piles driven to rock have recorded apparent settlements ranging from 0.7 in. (marker No. 19N) to 2.3 in. (marker No. 15S). The applicant notes, and we agree, that the movements of these markers were inconsistent with the movement at neighboring markers and that the apparent movements did not display a pattern indicative of the soils or rockfill consolidation settlement or a shear failure of the rockfill.

The applicant performed two additional surveys to confirm that the recorded movements of the above-mentioned four markers were due to these markers having been hit by construction equipment during placement of the rockfill. First, the pavement and the curbing of the road were surveyed. No pavement distress or curbing damage was noticed as a result of the apparent movement of the markers in the areas of concern. Secondly, the horizontal alignment of the four markers was checked and all four of them were found to be displaced laterally at the ground surface by 1-foot (markers 15S and 18S) to 1.5-foot (markers 17S and 19N). Approximate calculations performed by the applicant indicate that the lateral displacements of these magnitudes would correspond to the recorded vertical movements of the markers 15S, 17S, 18S, and 19N. These calculations are recorded in Figure Q2.86-7 submitted by the applicant in February 1981.

The staff has examined the additional observations made by the applicant along with the complete details of construction and composition of the structural elements of the ERCW lines and dike and has concluded that the recorded vertical movements of 4 out of the 12 markers on the ERCW dike can be explained by

the horizontal displacements of these markers, as reported by the applicant. This staff conclusion is supported by the following additional considerations:

1. The six markers (Nos. 20S, 20N, 21S, 21N, 22S, and 22N) located in the dike area that is not supported by the reinforced concrete slab have not shown significant settlements.

2. Of the 12 markers (Nos. 14S, 14N through 19S, and 19N) located on the 250 ft length of the dike where the ERCW pipes are supported by a 3'-0" thick reinforced concrete slab supported by piles driven to rock, only four damaged markers (15S, 17S, 18S, and 19N) recorded movements, even though all of the 12 markers are installed in areas that are subjected to similar loading. It is significant to note that undisturbed markers 15N, 17N, 18N, and 19S have not recorded significant settlements while disturbed markers 15S, 17S, 18S and 19N installed at the opposite edge of the concrete slab at the same cross sections have shown movements.

3. The movements recorded by the above four markers on the slab have not been continuous in time; they seem to have occurred in 'jumps' confirming the possibility that these movements have been due to disturbance of the markers. The incremental movements of these four markers from September 1980 to February 1981 have been insignificant. Of the 6 markers (Nos. 20S through 22N) that were installed to measure the settlement of the rockfill, only one marker (No. 21N that is reported to have been hit by construction equipment) has shown movement: this marker has recorded a movement of 0.40 in. in December 1979, 0.54 in. in March 1980, 0.47 in. in September 1980, and 0.53 in. in February 1981. The recorded movement between December of 1979 and February 1981 is considered insignificant.

Conclusions

In view of the above considerations, the staff is satisfied with the applicant's argument that the recorded movements of a few isolated markers do not indicate real settlement of the ERCW pipeline section along the rockfill access dike. The staff believes that the safety of the ERCW pipes is not likely to be affected by the slight settlements that may have actually occurred. Because the piles supporting the ERCW piping slab are reported to have been driven to refusal into weathered shale, it is unlikely that the ERCW pipes will be subjected to sufficient differential displacements that could cause stresses in excess of code allowable limits. The applicant will continue the settlement monitoring program along the ERCW alignment for a period of 3 years per letter of April 19, 1981; any settlement greater than 0.5 in that occurs during this period will be evaluated by TVA and reported to the NRC.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS AND COMPONENTS

3.5 Missile Protection

Tornado Missiles

Concern has been expressed that tornado-generated missiles might penetrate the roof of the auxiliary building and damage certain safety-related equipment. Specifically, the 480-V transformer room is located directly below ventilation openings in the roof. Missiles entering these ventilation openings could damage or destroy the 480-V safety-related transformers.

In the SER we stated that for Sequoyah protection should be provided against the following postulated missiles:

> Steel Rod, 1 inch diameter, 3 feet long, weight 8 pounds, traveling horizontally at 316 feet per second and vertically at 252 feet per second, at all elevations.
>
> Utility Pole, 13-1/2 inches diameter, 35 feet long, weight 1690 pounds, traveling horizontally at 211 feet per second and vertically at 169 feet per second, at all elevations less than 30 feet above grade within one-half mile of the facility structures.

The auxiliary building roof varies from 58 to 86 feet above plant grade, therefore, the utility pole is not considered as a potential missile which could damage the building roof or enter the ventilation openings. This limits the protection considerations for these areas to the potential effects of the one-inch-diameter steel rod.

As stated in the SER we consider concrete at least two feet thick with a strength of 4000 pounds per square inch to be adequate protection against all postulated tornado missiles in the Sequoyah region and do not require any additional evaluation. Portions of the auxiliary building roof varies from 9-1/2 to 13-1/2 inches, which is judged to provide adequate protection against the effects of a one-inch-diameter steel rod.

The auxiliary building roof contains several ventilation openings directly above the room which houses the 480-V transformers. These openings are of two sizes; 4 x 4 feet and 4 x 8 feet. As stated above, the roof consists of 4000 pounds per square inch concrete and varies in thickness from 9-1/2 to 13-1/2 inches. Consequently, the one-inch-diameter steel rod must have almost a vertical orientation to penetrate one of the ventilation openings.

When we consider the location of the 4 x 4-foot ventilation opening with respect to the transformers, we are of the opinion that the probability of a missile strike is very low. The solid angle subtended by the opening at the point of transformer location is small with respect to the solid angle formed by an imaginary hemisphere located above the roof of the building. The probability

of a missile strike is proportional to the ratio of the solid angle of the opening to that of the hemisphere and is, therefore, also quite small. This probability is further reduced as the size of a potential missile is increased with respect to the size of the opening. Considering a steel bar three feet in length which is aerodynamically unstable in flight (i.e., having a tumbling motion) there is a high probability that even though a missile struck the opening, it would be deflected from its strike path.

A similar judgement can be derived when considering the 4 x 8-foot opening. However, in this case the opening is located some distance from the transformer (approximately 8 feet). Therefore, the subtended solid angle would be even smaller with a commensurately lower strike probability.

The probability of multiple missiles striking redundant transformers which are located in separate rooms is proportional to the products of the individual strike probabilities since the rooms are separated by a reinforced concrete block wall from floor to ceiling. In our judgement the multiple strike probability is extremely small and need not be considered a threat to the safe shutdown capability of the plant.

Our review also considered the tornado missiles striking the exhaust fan housings which are above each ventilation opening. Generally, it is our position that the unprotected targets exposed to tornado wind fields are subject to missile damage and that credit for redundancy and separation may not be appropriate. In view of this we assume that all the fans themselves would be lost. It was further considered that all the ventilation openings were damaged in such a manner as to simultaneously block all ventilation flow. In actuality it is more likely that the missiles would tear away the weather covers over the openings. However, even in the unlikely case where the ventilation openings are sealed, the transformers are capable of functioning effectively for a period of more than an hour before reaching an unacceptably high temperature. The licensee has provided emergency procedures which require operating personnel to survey the plant for any damaged sustained during any natural phenomena and take any necessary corrective action. Thus, when all the exhaust fan openings are found to be damaged and obstructing the exhaust air flow, the operating personnel would have ample time to open the normally closed doors to the transformer rooms and utilize portable fans to prevent overheating of the transformers.

Based on our evaluation regarding the relative locations of the ventilation openings and the shutdown transformers, the flight path and dynamics of tornado-generated missiles, it is our opinion that the probability of a tornado-generated missile or missiles incapacitating both transformer trains and preventing safe shutdown of the reactor plant is very small.

We have requested the applicant to provide information which assures that their design provides adequate protection for the 480-V transformers against tornado missile strikes or that additional protection be proposed for our review and approval. When the above information is available, we will be able to complete our evaluation.

Resolution of this matter should not restrict operation of the plant as information described in WASH-1300 suggests that the probability of a tornado striking

the Sequoyah site is sufficiently low (on the order of 10^{-3} per year) as to allow plant operation to proceed up to the first refueling while this matter is being resolved and any necessary fixes are approved and installed.

3.8 Design of Seismic Category I Structures

The masonry walls for the Sequoyah Nuclear Plant Unit 2 have been reviewed and found acceptable based on NRC interim criteria. Prior to startup following the first refueling, or as directed by the Commission, TVA shall evaluate all seismic Category I masonry walls to final staff criteria and implement required modifications that are indicated by that evaluation. Both reinforced and nonreinforced walls are used. The nonreinforced walls are of two distinct types--mortared joints and nonmortared joints.

The reinforced masonry walls are designed in accordance with ACI 531-79. No piping is supported on these walls however some electrical conduit are attached with through-wall bolts or spread anchors in the concrete fill of the masonry blocks. The earthquake loads are computed using the floor response spectra for the attaching floor slab.

The nonreinforced block fill-ins were surveyed to determine if their collapse would endanger any seismic Category I equipment. If the block would not strike any seismic Category I equipment they were considered acceptable. If any equipment would be struck then the fill-ins were analyzed and reinforced if necessary. Ten areas were reinforced by banding with steel straps and anchoring the bands to adjoining structure. The areas reinforced were primarily in the Auxiliary Building. None of the areas were in the containments.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.4 Containment Isolation Systems

We have re-examined the isolation provisions, compared to the requirements of GDC 57, for the feedwater system at Sequoyah Unit 2, and have found several deficiencies.

GDC 57 requires, for a closed system inside containment (such as the feedwater system), that each line have at least one isolation valve outside containment which is either automatic, or locked closed, or capable of remote manual operation. Also, a simple check valve may not be used as the automatic isolation valve.

Each of the four main feedwater lines has a simple check valve designated as an isolation valve. However, upstream of each check valve, within the safety-grade (Class B) portion of the system, is an automatic check valve that meets the requirements of GDC 57 for an isolation valve. Therefore, if the automatic valve is designated as the containment isolation valve, the requirements of GDC 57 are met for each main feedwater line.

Each of the four auxiliary feedwater lines also has a simple check valve as its containment isolation valve. However, upstream of each check valve are remote manual valves which may be designated containment isolation valves. These valves are in the safety-grade (Class C) portion of the system. Therefore, if the remote manual valves (LCV 3-175, 3-171, 3-171A, 3-174, 3-164, 3-164A, 3-173, 3-156, 3-156A, 3-172, 3-148, and 3-148A) are designated as containment isolation valves, the requirements of GDC 57 are met for the auxiliary feedwater system.

On each of the four main feedwater lines, and on two of the auxiliary feedwater lines, there is a one-inch-diameter chemical feed line joining the main line downstream of the check valve. Each of these one-inch lines has a simple check valve as an isolation valve. The applicant must modify each of these lines to satisfy the requirements of GDC 57. To meet these requirements, the applicant must install a safety-grade isolation valve of an appropriate type (i.e., automatic, remote manual, or locked-closed manual, but not simple check) in the safety-grade portion of each line. The applicant's license must be conditioned to complete these modifications by the end of the first refueling outage. In the interim, an exemption from the explicit requirements of GDC 57 is acceptable in accordance with the Introduction to Appendix A of 10 CFR Part 50.

Interim acceptance of the present isolation provisions in the one-inch lines, i.e., the simple check valves, is based on other system design considerations. For example, there are additional check valves and normally closed manual valves upstream of the check valves. Also, the secondary system forms a

closed system inside containment. Because of the need to assure secondary system integrity inside containment in the event of a LOCA, the system has been seismically designed and pipe whip and missile protected. Therefore, rupture of the secondary system is not postulated to occur either concurrent with or as a result of a LOCA. Also, the small size of the lines (one-inch diameter) lessens the severity of possible adverse consequences of post-LOCA isolation degradation. With this assurance of system integrity and additional valves, the check valves are found to be acceptable containment isolation valves in the interim.

With the requirement that the applicant modify the one-inch chemical feed lines to bring them into compliance with GDC 57 by the end of the first refueling outage, we conclude that the containment isolation provisions for the main and auxiliary feedwater lines are acceptable.

6.2.6 Containment Leakage Testing Program

By letter dated April 23, 1981, the applicant requested an exemption for Sequoyah Nuclear Plant Unit 2 from certain requirements of 10 CFR Part 50, Appendix J, paragraph III.D.2(b)(ii), which states:

> "Air locks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at not less than P_a."

Whenever the plant is in mode 5 (cold snutdown), containment integrity is not required. Hence, if an air lock is opened during mode 5 operations, paragraph III.D.2 (b)(ii) requires that an overall air lock leakage test at not less than P_a be conducted prior to entry into mode 4.

Even if the periodic 6-month test required by paragraph III.D.2(b)(i) of Appendix J has been satisfied to meet the requirement of paragraph III.D.2(b)(ii), no access to the containment can be allowed while preparing to leave mode 5 until every air lock that has been opened in mode 5 is first tested and the plant has entered mode 4. The test would effectively be required every time mode 5 was entered. The containment would have to be cleared of employees during performance of this test or they would be required to remain inside containment during the test and until the plant reached mode 4. Usually there are several minor operational and maintenance problems that require containment entry just prior to entering mode 4; the special air lock test would have to wait until all problems requiring containment entry were first corrected. This is a very restrictive requirement and would slow the process of returning to operation. If the periodic 6-month test of paragraph III.D.2(b)(i) and the test required by paragraph III.D.2(b)(iii) are current, no maintenance has been performed on the air lock, and the air lock is properly sealed, there should be no reason to expect the air lock to leak excessively just because it has been opened in mode 5 or mode 6.

Accordingly, we conclude that the applicant's proposed approach of substituting the seal leakage test specified in Technical Specifications surveillance requirement 4.6.1.3.a is acceptable when no maintenance has been performed on the air lock. Whenever maintenance has been performed on an air lock, the requirements of paragraph III.D.2(b)(ii) must still be met by the licensee.

Therefore, an exemption from this requirement (10 CFR Part 50, Appendix J, paragraph III.D.2 (b)(ii)) is justified and acceptable for Sequoyah Unit 2. The Technical Specification surveillance requirement 4.6.1.3.b for Sequoyah Unit 2 is rewritten as follows:

> By conducting an overall air lock leakage test at not less than P_a (12 psig) and by verifying the overall airlock leakage rate is within its limit:
>
> 1. At least once per 6 months, and
>
> 2. Prior to establishing CONTAINMENT INTEGRITY if opened when CONTAINMENT INTEGRITY was not required when maintenance has been performed on the air lock that could affect the air lock sealing capability.

7 INSTRUMENTATION AND CONTROL

7.2 Reactor Trip System

7.2.2 Process Analysis System

Environmental Qualification for Safety-Related Electrical Equipment

In December 1979, the staff issued guidance for the environmental qualification of safety-related electrical equipment (NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"). By letter dated February 21, 1980, the staff requested TVA to review the environmental qualification documentation for each item of safety-related electrical equipment which could be exposed to a harsh environment so as to identify the degree to which the associated environmental qualification program complies with the staff's position as described in this NUREG. Further, where there are deviations, we requested the applicant to provide the basis for concluding that the associated environmental qualification program demonstrates that each item in question is environmentally qualified for its service conditions. In response to this request, TVA submitted information through letters dated June 16 and October 31, 1980 and February 5, 1981.

The Commissioner's Memorandum and Order dated May 23, 1980 directs the staff to complete its review of environmental qualification including the publication of the safety evaluation reports for all operating reactors. Also, this order directs that by no later than June 30, 1982, all electrical equipment in operating reactors subject to this review be in compliance with NUREG-0588 or Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors.

The staff conducted audits on August 5 and 6, 1980 and December 17-19, 1980 of the environmental qualification documentation and/or test data for electrical equipment which could be exposed to a harsh environment for Sequoyah Unit 1.

Because the equipment in Units 1 and 2 is essentially identical, with few exceptions, the results of the Sequoyah Unit 1 audits are applicable to Unit 2. In addition to the audits, the staff reviewed the licensee's systems evaluation and service conditions, and compared the qualification values with the specified values required by the licensee's design.

By letter dated May 15, 1981, we transmitted to TVA preliminary results of our review of environmental qualifications of safety-related electrical equipment at Sequoyah 2. This review identified three items, solenoid valves, level transmitters, and handswitches which the TVA stated, and we agreed, required immediate corrective action. TVA replaced the solenoid valves and level transmitters and removed the unqualified handswitches from safety-related control circuits. Also identified were a number of potential equipment deficiencies involving a lack of proper documentation, inadequate justification of assumed environmental conditions following an accident, and/or

inadequate environmental testing of equipment such that conformance to NUREG-0588 could not be demonstrated. TVA was required to respond within 10 days of receipt of this report with a written statement supporting the safe operation of their facility taking into account the NRC staff's preliminary list of deficiencies. TVA responded by letters dated May 26 and 28, 1981, that appropriate corrective actions which the staff identified had been taken and concluded that Sequoyah 2 is in conformance with GDC 4 and could operate in a safe manner.

The NRC technical review has been completed. A Safety Evaluation Report has been prepared which confirms the preliminary results forwarded to TVA and identifies no further outstanding items which require immediate corrective action. This SER requires TVA to provide, within 90 days, documentation of the missing qualification information which demonstrates that such equipment meets NUREG-0588 or commit to a corrective action (requalification, replacement, relocation, and so forth) consistent with the requirements to establish qualification by June 30, 1982. If the latter option is chosen, the licensee must provide specific justification for operation until such corrective action is complete.

In this SER, the staff concludes that conformance with the above requirements and satisfactory completion of the corrective actions by June 30, 1982 will ensure compliance with the Commission's Memorandum and Order of May 23, 1980. The staff further concludes that there is reasonable assurance of safe operation of this facility pending completion of these corrective actions.

With regard to GDC 4, the staff interprets the Commission's Memorandum and Order of May 23, 1980 (CLY-80-21) that GDC-4 is being met for a facility, even though full compliance with the DOR guidelines or NUREG-0588 is not yet achieved, if the following conditions are met:

1. Where equipment required immediate action with respect to environmental qualifications, the licensee has taken practical actions to upgrade the facility by modification, relocation, or replacement of equipment or procedural action,

2. The licensee has demonstrated a program to achieve compliance with the Commission's Memorandum and Order regarding replacement parts and installed equipment, and

3. The staff's conclusions show that there is reasonable assurance of safe operation of the facility with currently installed equipment.

The staff takes this view because the Commission recognized in CLI-80-21 that current qualification was insufficient to meet the guidelines and, therefore, ordered a program to assure compliance with the guidelines by June 30, 1982 as a satisfactory demonstration of compliance with GDC 4.

9 AUXILIARY SYSTEMS

9.5 Fire Protection Systems

In Supplement No. 2 to the safety evaluation report, we stated that when the proposed rule concerning fire protection and its Appendix R becomes effective, the provisions of the rule applicable to Sequoyah 1 and 2 would be implemented in accordance with the rule. The rule (10 CFR 50.48) and Appendix R to 10 CFR Part 50 became effective on February 19, 1981 but none of its provisions applied to these plants. However, the technical requirements set forth in Appendix R are now being used as staff guidelines in our fire protection reviews for these and other plants under operating license review.

By letter dated April 2, 1981, TVA considers that no modifications are required at Sequoyah as a result of Appendix R. However, since the previous staff review of Sequoyah was not specifically conducted to Appendix R requirements, TVA has agreed to accept a license condition for Sequoyah Units 1 and 2 requiring the preparation of a report by October 1, 1981 that identifies and justifies differences between existing or proposed fire protection features of Sequoyah 1 and 2 and those features specified in Sections III.G, III.J, III.L, and III.O of Appendix R to 10 CFR Part 50. Based on a review of this information, the staff will decide what modifications, if any, need to be implemented at these facilities. These modifications will be implemented on a schedule consistent with that required for other operating reactors, unless some later schedule has been justified.

In addition to the issue of compliance with Appendix R, our previously issued Supplement No. 2 also identified additional fire protection modifications that would be needed prior to Unit 2 startup dealing with the essential raw cooling water (ERCW) system. These modifications are expected to be completed in June 1981.

Since the ERCW system is needed for two-unit operation, TVA proposed in its letter of March 9, 1981 to institute the following interim measures until these fire protection modifications are complete:

(1) A continuous fire watch in the area of ERCW junction box on elevation 690.0 of the auxiliary building.

(2) A roving fire watch in the area of the conduits which exit the top of the junction box, pass through floor elevation 714.0, and terminate on floor elevation 734.0.

These interim measures are acceptable to the staff.

Subsequent to issuance of Supplement No. 2, we found that control room plastic ceiling panels installed in Units 1 and 2 did not meet our licensing guidelines. We requested that the plastic panels be removed and replaced with a more suitable material. TVA, by letter dated April 30, 1981, proposed replacement

panels consisting of an aluminum grid system that is covered by a vinyl dust cover. The support system is Paralume 1 aluminum parabolic grid that will not burn. The vinyl cover is U.L. listed material with a flame spread rating of 15. We conclude that the proposed new ceiling panel material meets our fire protection guidelines and is, therefore, acceptable. We will require that the new ceiling panels be installed prior to exceeding 5 percent of full power.

During a previous site visit, we noted that the control room had been carpeted. By letter dated February 9, 1981, we requested that the existing carpeting be removed. By letter dated April 30, 1981, TVA submitted fire test results applicable to the carpet in the control room. The test results indicate that the carpet exhibits fire resistance and should be classified as a limited combustible material. The test results also show that the carpet would not exhibit fire propagation characteristics for postulated fires in the control room. Based on our evaluation, we find that the carpet in the Sequoyah control room meets Section D.1.d of Appendix A to BTP 9.5-1, and, therefore, is acceptable and need not be removed.

Based on this and our previous evaluations, we find that the fire protection program for the Sequoyah Nuclear Plant is adequate at the present time from a safety standpoint since it meets the guidelines contained in Appendix A to BTP 9.5-1 or provides adequate interim measures and meets the requirements of GDC-3. Further, since TVA has agreed to accept a license condition which will require the preparation of a report which identifies and justifies any differences between the fire protection features required by Appendix R and those provided on Sequoyah 1 and 2. Based on the staff's review of that report, further improvements in the Sequoyah fire protection features will be implemented on a schedule consistent with that required for other operating reactors. For the period of time until the fire protection system improvements yet to be implemented become operational, we consider that the existing fire detection and suppression systems; the existing barriers between fire areas; improved administrative procedures for control of combustibles and ignition sources; the trained onsite fire brigade, the capability to extinguish fire manually; and the fire protection technical specifications provide adequate protection against potential damaging fires at this facility and assure that a fire occurring in any area will not prevent the plant from being brought to a safe cold shutdown.

On this basis, we conclude that Sequoyah Units 1 and 2 are acceptable for full power operation from a fire protection standpoint.

11 RADIOACTIVE WASTE MANAGEMENT

Process Control Program (PCP)

On April 3, 1981, TVA submitted a revised PCP describing the methodology for packaging radioactive spent resins generated at Sequoyah Nuclear Plant Units 1 and 2. At this time, the solid radioactive waste treatment system described in NUREG-0011 (March 1979) and Supplement 1 (February 1980) is capable of dewatering radioactive spent resin from the shared system and a portable demineralizer system installed for treating wastes from the plant. Plans are underway to revise the method for solidifying "wet" radioactive wastes to meet the acceptable criteria for offsite shipment and subsequently revise the PCP by July 3, 1983. The staff has re-reviewed the inventory, generation, and retention of spent resins and finds that there is adequate capacity in the design for the solid radioactive waste treatment system, and that the PCPs for dewatered resin and plant procedures are acceptable. The Technical Specifications for Unit 2 will utilize the approved PCP for solidification at Units 1 and 2.

17 QUALITY ASSURANCE

In Supplement No. 2 to the SER we stated that our review of the quality assurance program description for the operations phase for the Sequoyah Nuclear Plant verified that the criteria of Appendix B to 10 CFR Part 50 have been adequately addressed in Chapter 17 of the FSAR. This determination of acceptability included a review of the list of items to which the quality assurance program applies.

The list of items was reviewed by the technical review branches to assure that safety-related items within their scope of review fall under the quality assurance program controls. The list has been expanded to include safety-related items reflected in NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980. Differences between the staff and the applicant regarding the list have been resolved to the staff's satisfaction. Therefore, the staff has no open items concerning the quality assurance program for operations or to what the program applies.

22 TMI REQUIREMENTS

22.2 Full-Power Requirements

I. Operational Safety

I.A.1.1 Shift Technical Advisor

Position

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the STAs that pertain to the engineering aspects of assuring safe operations of the plant, including the review and evaluation of operating experience.

Discussion

In a letter dated November 13, 1980, TVA submitted a description of their STA training program and their plans for requalification training. TVA stated that the STAs on duty beginning January 1, 1981 have completed this program. The STA training program covers the same technical areas as listed in the INPO document entitled, "Nuclear Power Plant Shift Technical Advisor Recommendations for Position Descriptions, Qualifications, and Education and Training."

We find that this requirement of NUREG-0737 has been satisfied provided a fully trained technical advisor is provided to the shift supervisor.

I.A.1.3 Shift Manning

Position

This position defines shift manning requirements for normal operation. The letter of July 31, 1980 from D. G. Eisenhut to all power reactor licensees and applicants (copy attached) sets forth the interim criteria for shift staffing (to be effective pending general criteria that will be the subject of future rulemaking). Overtime restrictions were also included in the July 31, 1980 letter.

Discussion

TVA meets the requirements for shift manning for one unit operation at Sequoyah Nuclear Plant. Sequoyah Unit 1 Technical Specification 6.2.2, "Unit Staff,"

lists the minimum shift crew for single unit operation. The Technical Specifications for Unit 2 include minimum shift crew requirements for operation of two units with a single control room. We consider this requirement of NUREG-0737 is met. The Unit 1 Technical Specification will be revised to be consistent with Unit 2 specifications.

I.B.1 Organization and Management Criteria

The material in this section is in addition to that stated in Section I.B.1 of Supplement No. 1. The following position is that taken from Supplement No. 1.

Position

Assure that the applicant meets the requirements for onsite and offsite support personnel, both management and technical, that will assure safe operation of the plant during normal and abnormal conditions and provide the capability necessary to respond to accident situations.

Items to be considered include (a) competence of management and technical staff, both onsite and offsite; (b) size of offsite staff and degree of involvement in plant operations; (c) types of expertise needed; (d) pooling of resources among utilities; (e) organization arrangements for both normal and accident situations; (f) training of management and technical personnel, both onsite and offsite, to assure full knowledge of plant operations and reactor safety; (g) staffing of control room personnel; (h) quality assurance program and staffing; (i) financial capability (in the event reliance is placed on outside contractual assistance during the accident situation); (k) procedures for normal operations, accident conditions, surveillance, and maintenance; (l) special requirements for accident situations including control room access, onsite technical support center, and onsite operational support center; (m) status of preestablished plans for using available resources in the event of unusual situations; (n) reporting of unusual events; and (o) policy for the consideration at management levels of safety issues identified at all levels, but unresolved.

Discussion

TVA is a very large utility with more than 45,000 employees. It does its own design engineering and it handles its own construction using in-house forces; as a result, it has an impressive in-house technical capability to apply to potential problems. At the same time, TVA has a large commitment to nuclear power. There presently are four TVA nuclear units in operation at two different sites (Browns Ferry 1, 2, and 3 and Sequoyah Unit 1). In addition, there are 13 nuclear units under construction at six different sites, including Sequoyah Unit 2.

The applicant's performance was recently assessed in a memorandum from James P. O'Reilly, Director of the NRC's Region II office, dated January 30, 1981, to the Chairman, "SALP Board Results for Tennessee Valley Authority." This report provided an assessment of TVA's performance, both at the individual nuclear plant sites and on an overall basis, in comparison with other nuclear units within the NRC Region II area. The report covered the period from April 1, 1979 to August 31, 1980, although evaluations of particular plants varied within this period; the report is available in the NRC's Public

Document Room. The report found that construction activities at four of the TVA nuclear plant sites, including Sequoyah Unit 2, were above average as compared to other plant sites within the Region II area. Construction activities at two sites were rated below average on the same basis. Operational activities at the Browns Ferry site were rated as acceptable, but below average, in comparison to other operating plants in Region II, while operations at Sequoyah Unit 1 were rated as acceptable. Problems identified at the individual sites reflect an apparent unevenness of management attention to some areas, notably quality assurance and adherence to procedures.

Overall, the SALP evaluation of TVA was as follows:

> It is difficult to arrive at an overall evaluation due to the many different inputs to the evaluations (i.e., construction and operation) with these inputs providing widely divergent results. An overall evaluation of TVA places it slightly below average for utilities in Region II. TVA's largeness is not providing the excellence of operations that it is capable of, at operating or construction sites. Site discipline is lax as exemplified by their attitude toward procedural adherence and the apparent lack of control exercised by the supervisors. Region II has identified these areas to TVA management and will continue to monitor their progress toward improved performance.

However, the evaluation also noted:

> TVA is generally responsive to NRC regulations and findings of noncompliance. TVA's size and large nuclear commitment have allowed tremendous technical support resources to be developed within its organization. TVA has initiated a Nuclear Safety Review Staff which is to perform independent reviews of safety significant areas. This staff should provide valuable aid to focusing high-level management attention on potential problem areas.

The SALP team audit of Sequoyah Unit 1 covered the period from August 1, 1979 to March 29, 1980. Since Sequoyah Unit 1 did not receive its 5% power operating license until February 29, 1980, this audit period covered only 1 month of plant operation. The overall evaluation of Sequoyah Unit 1 was:

> The licensee performance of licensed activities is acceptable. This facility was recently licensed and therefore the evaluation as an operational facility covers a relatively small period of time. Apparent trends in noncompliance and LER completeness will be closely monitored to ensure they are corrected. Increased inspection scope is recommended for three areas to assure that corrective actions are adequately implemented. NRR project manager indicated that good communications existed with the licensee and no problem areas had developed.

The three problem areas noted pertain to effluent monitoring, fire protection, and the quality and timeliness of submission of Licensee Event Reports.

On February 11, 1981, an incident occurred at Sequoyah Unit 1 involving an inadvertent containment spray actuation. Subsequent investigation by the NRC's Office of Inspection and Enforcement revealed that the event was largely attributable to a combination of inadequate training to auxiliary unit operators, failure to implement or utilize procedures governing valve alignment in the reactor heat removal system, and failure of administrative procedures to clearly delineate authorities and responsibilities for all operations personnel, specifically auxiliary unit operators involved in safety-related activities.

On the basis of (1) our knowledge of TVA, (2) our earlier evaluation of the TVA management capability for operation of the Sequoyah Nuclear Plant, (3) the results of the SALP team audit of TVA, and (4) the findings of the team investigating the February 11, 1981 containment spray actuation incident at Sequoyah Unit 1, we conclude that TVA does have the technical resources and management capability to support and control the safe operation of both Units 1 and 2 of the Sequoyah Nuclear Plant. However, we consider that the SALP team audit and the investigation of the February 11, 1981 incident have revealed areas where TVA management needs to intensify their efforts to improve performance. Specifically, these are:

1. Training of auxiliary unit operators, and other unlicensed personnel, whose activities in the plant may affect safety-related equipment and systems.

2. Adequacy of and adherence to administrative procedures delineating authorities and responsibilities of all operations personnel, with specific attention to auxiliary unit operators engaged in safety-related activities.

Measures for implementing the above items by TVA were reviewed and approved by IE prior to permitting TVA to restart Unit 1. Also, TVA was informed that their LER reports should be improved to provide a more descriptive account of such incidents as the spray event. TVA agreed to improve the quality of their reporting, consistent with the format provided by the NRC.

22.1.2 Independent Safety Engineering Group

Position

Each applicant for an operating license shall establish an onsite independent safety engineering group (ISEG) to perform independent reviews of plant operations.

The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent review and audits of plant activities including maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. ISEG will then be in a position to advise utility management on the overall quality and safety of operations. ISEG need not perform detailed audits of plant operations and shall not be responsible for sign-off functions such that it becomes involved in the operating organization.

Discussion

By letter dated August 11, 1980, TVA agreed to maintain the independent safety engineering group. This requirement has been incorporated in the Technical Specifications for Units 1 and 2 as well as a license condition.

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

Position

In letters of September 13 and 27, October 10 and 30, and November 9, 1979, the Office of Nuclear Reactor Regulation required licensees of operating plants, applicants for operating licenses, and licensees of plants under construction to perform analyses of transients and accidents, prepare emergency procedure guidelines, upgrade emergency procedures, including procedures for operating with natural circulation conditions, and to conduct operator retraining (see also item I.A.2.1). Emergency procedures are required to be consistent with the actions necessary to cope with the transients and accidents analyzed. Analyses of transients and accidents were to be completed in early 1980 and implementation of procedures and retraining was to be completed 3 months after emergency procedure guidelines were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions are being developed. In the course of review of these matters the staff will follow up on the Bulletin and Order matters relating to analysis methods and results, as listed in NUREG-0660, Appendix C (see Table C.1, items 3, 4, 16, 18, 24, 25, 26, 27; Table C.2, items 4, 12, 17, 18, 19, 20; and Table C.3, items 6, 35, 37, 38, 39, 41, 47, 55, 57).

Discussion

In Supplement No. 2, we stated that TVA provided an adequate response to this item in accordance with NUREG-0694. The issuance of NUREG-0737 provided further guidance on this matter. In a letter dated December 19, 1980, TVA stated they were a member of the Westinghouse Owners' Group which has committed to and is responding to the requirements for this item. We have concluded that the actions called for in Task Action Plan, Items I.C.1.a(1), LOCA, I.C.1.a(2), Inadequate Core Cooling, have been adequately completed. Future actions addressed by Task Action Plan Items I.C.1.a(3), Transients and Accidents, and I.C.9, Long-Term Program Plan for Upgrading of Procedures, may require future revisions to the emergency procedures. These revisions will be identified in the long-term program stipulated in Item I.C.9. On this basis we consider this requirement satisfied.

I.C.6 Procedures for Verifying Correct Performance of Operating Activities

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Implementation of automatic status monitoring if required will reduce the extent of human verification of operations and maintenance activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases--one before and one after installation of automatic status monitoring equipment, if required, in accordance with item I.D.3.

Discussion

In a letter dated May 11, 1981, the applicant committed to implement a system for verification of correct performance of operating activities prior to issuance of a full power license. The system described is consistent with the clarification in NUREG-0737. The system includes initial system alignment and verification, recording of changes in alignment on systems status sheets, and verification of operability or alignment verification prior to returning equipment to service. The shift supervisor or an authorized Senior Reactor Operator must approve removal from and return of equipment to service. Alignment verifications may be performed by Assistant Unit Operators who have sufficient training and familiarity with plant systems to ensure correct system alignment. The adequacy of the verification system will be determined by the Office of Inspection and Enforcement. This satisfies the requirements. This was not a requirement for licensing Unit No. 1 for full power operations; however, a post implementation review for Unit 1 will be performed by IE.

I.D.1 Control Room Design Review

Position

In accordance with Task Action Plan I.D.1, NUREG-0660 and clarification of Task Action Plan requirements, NUREG-0737, all licensees and applicants for operating licenses will be required to conduct a detailed control room design review to identify and correct design deficiencies. This detailed control room design review is expected to take about one year. Therefore, the Office of Nuclear Reactor Regulation (NRR) requires that those applicants for operating licenses who are unable to complete this review prior to issuance of a license make preliminary design assessments of their control rooms to identify significant human factors deficiencies and establish a schedule approved by NRC for correcting deficiencies. However, these applicants will be required to complete the more detailed control room reviews on the same schedule as licensees with operating plants.

Discussion

In Section IV of Part II of Supplement No. 1 and Section 22.2, I.D.1 of Supplement No. 2, we identified a number of corrective actions which we believed were necessary to improve the Unit 1 operator effectiveness during an upset or accident condition. TVA was required to implement a number of corrective actions in the Unit 1 control room prior to criticality and several other corrective actions before escalation beyond 5 percent of rated power.

Because of the similarity between the Units 1 and 2 control rooms, we will require that all corrective actions specified for Unit 1 also be implemented on Unit 2, as appropriate. In a letter dated August 11, 1980, TVA has documented proposed changes to the Unit 1 control room and later confirmed that Unit 1 improvements will be made on Unit 2.

We conclude that implementation of the Unit 1 improvements in Unit 2 will enhance the operator's detection and response capability to permit safe low power testing and full power operation. I&E Resident Inspector will verify implementation of the required corrective actions for both units.

I.G.1 Training During Low-Power Testing

Position

The TMI Task Action Plan states that applicants for operating licenses will perform a set of low-power tests to increase the capability of shift crews and ensure training in plant evolutions and off-normal events. Near-term operating license facilities will be required to develop and implement intensified exercises during the low-power testing programs. This may involve the repetition of startup tests on different shifts for training purposes.

Discussion

In a letter to the NRC dated December 16, 1980, the applicant indicated that no useful purpose would be served by repeating the special natural circulation tests on Sequoyah Unit 2 that were previously performed on Unit 1. The applicant's position was based on the following:

1. Many of the Unit 2 operators participated in the Unit 1 tests.

2. All Sequoyah licensed operators receive simulator training in natural circulation.

3. A simulator improvement and verification program, and a comparison of Unit 1 test data with the simulator model performance, verified that the simulator adequately modeled plant behavior and therefore provided for effective operator training.

We have considered the acceptability of substituting simulator training for actual plant tests. Our acceptance criteria for this determination were as follows:

1. TVA should provide evidence that the simulator accurately models natural circulation responses.

2. TVA should verify that operators receive simulator training in natural circulation evolutions in which the operators perform adjustments in charging and letdown flow, pressurizer auxiliary spray, steam dumping, and pressurizer heater use, to control coolant system pressure, heat removal rate, and subcooling margin.

In a letter dated April 30, 1981, TVA provided further evidence of the accuracy of the simulator model. Discussions with I&E training personnel who use the TVA simulator further confirmed the capability of the simulator.

Discussions with TVA training personnel on May 7, 1981, revealed that simulator natural circulation training is obtained by using the following four emergency operating procedures:

1. LOCA

2. Steam Generator Tube Rupture

3. Main Steam Line Break

4. Loss of Offsite Power

During the performance of these emergency procedures, operators perform the desired natural circulation control manipulations discussed above.

Based on the above we have concluded that the Special Low Power Test Program that was performed on Sequoyah Unit 1 need not be repeated on Unit 2 for training purposes. Furthermore, since Unit 2 is a duplicate of Unit 1, we also have concluded that no meaningful technical data would be obtained by repeating the tests on Unit 2. We will condition the license, however, to state that IE will verify that licensed Unit 2 operators have completed simulator training for natural circulation conditions prior to exceeding 5 percent power level. One experienced operator trained on Unit 1 low power testing for natural circulation operation shall be assigned to each shift prior to exceeding 5 percent power level. Requirement remains in effect until TVA submits a report and NRC agrees with findings that an acceptable level of training and experience on Unit 2 has been attained.

II. Siting and Design

II.B.1 Reactor Coolant System Vents

Position

Each applicant and licensee shall install reactor coolant system (RCS) and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensible gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the vents shall conform to the requirements of Appendix A to 10 CFR Part 50, "General Design Criteria." The vent system shall be designed with sufficient redundancy that assures a low probability of inadvertent or irreversible actuation.

Each licensee shall provide the following information concerning the design and operation of the high point vent system:

(1) Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for loss-of-coolant accidents initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10 CFR 50.46.

(2) Submit procedures and supporting analysis for operator use of the vents that also include the information available to the operator for initiating or terminating vent usage.

Discussion

In Supplement No. 2 to the SER we concluded that this item was acceptable for licensing the Sequoyah units. In Section 22.3 of this supplement, we state that the installation date of the RCS vents is July 1982 for Unit 2 in accordance with NUREG-0737. We will so condition the license.

II.B.2 Plant Shielding

Position

With the assumption of a postaccident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4 (i.e., the equivalent of 50 percent of the core radioiodine, 100 percent of the core noble gas inventory, and 1 percent of the core solids are contained in the primary coolant), each licensee shall perform a radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during postaccident operations of these systems.

Each licensee shall provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or postaccident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

Discussion

In a letter dated June 16, 1980, TVA submitted the Sequoyah shielding design review report. The staff reviewed this report and finds it adequate. On the basis of this review the staff determined that no additional shielding is required at the Sequoyah Nuclear Plant Units 1 and 2.

Therefore, we find that this requirement of NUREG-0737 has been satisfied.

II.B.3 Postaccident Sampling Capability

Position

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 rems and 18.75 rems to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines, and cesiums (which indicate high fuel temperatures), and nonvolatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications or equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).

Discussion

In Supplement No. 2 to the SER, we stated that this item is satisfactorily resolved in licensing the Sequoyah units. NUREG-0737 has changed the completion date to January 1, 1982. We will condition the license for Unit 2 in conformance with the above requirement.

II.B.4 Training for Mitigating Core Damage

Position

Licensees are required to develop a training program to teach the use of installed equipment and systems to control or mitigate accidents in which the core is severely damaged. They must then implement the training program.

Discussion

TVA has a training program that meets all the requirements stated above. This initial training program, submitted on July 22, 1979, has been completed for all currently licensed Sequoyah Unit 2 operations personnel. An abbreviated program of the operator training will be presented to managers and technicians in the Health Physics, Plant Chemistry, and Instrumentation and Controls Sections commensurate with their responsibilities in the event of a core damaging accident.

By letter dated May 5, 1981, TVA has confirmed full implementation of this training program as described in their letter of December 19, 1980.

Based on the foregoing, we have concluded that the Sequoyah Nuclear Plant has provided adequate training of all licensed operating personnel for Unit 2 in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged.

II.B.7 Analysis of Hydrogen Control

Position

Reach a decision on the immediate requirements, if any, for hydrogen control in small containments, and apply, as appropriate, to new OLs pending completion of the degraded core rulemaking.

Discussion

Item II.B.7 of the TMI Action Plan, NUREG-0660, May 1980, provides that certain analyses be performed relative to hydrogen control for nuclear plants with small containments. These analyses have been performed and the results reported in SECY 80-107, dated February 22, 1980.

The staff's licensing requirements relative to provisions for hydrogen control beyond those prescribed in 10 CFR 50.44 have evolved from numerous deliberations among the Commission, the ACRS, the staff, and applicants and licensees. A summary statement of the staff's requirements for ice condenser containments is that a supplemental hydrogen control system be provided so that the consequences of that hydrogen which is generated during the more probable degraded core accident sequences do not involve a breach of containment nor adversely affect the functioning of essential equipment.

For Sequoyah Unit 2, the staff's licensing requirements are substantially the same as those that were required for Sequoyah Unit 1. For reasons explained below the air handling units, used for normal refrigeration in the ice condenser,

will now also be tripped for both units for accidents in which the supplemental hydrogen control system is 'uated. We have reviewed the interim hydrogen control system and concludeu chat it will provide with reasonable assurance protection against breach of containment in the event that a substantial quantity of hydrogen is generated. Moreover, the Tennessee Valley Authority (TVA) must provide on a timely schedule the bases for a Commission determination by January 31, 1982 that an adequate hydrogen control system for the plant is installed and will perform its intended function in a manner that provides adequate safety margins.

The TVA has installed in Sequoyah Unit 2 the interim distributed ignition system (IDIS) for hydrogen control in the event of a degraded core accident.

The IDIS at Unit 2 is identical to the system for Unit 1. A discussion of the IDIS for Sequoyah Unit 1 is contained in Supplements 3 and 4 of the Sequoyah Safety Evaluation Report.

Based on the results of our review of the IDIS for Unit 1 and on the results of our review of a comparable system for the McGuire plant, we find, as we did for Unit 1 in Supplement 4 to the SER, that a distributed ignition system for Unit 2 is acceptable as an interim hydrogen control measure for degraded core accidents.

The evaluation of a deliberate ignition system as a technique for hydrogen control is a topic of ongoing investigation by both the industry and the NRC. As a result of this ongoing review, including our work in connection with the McGuire proceeding, the staff has identified a number of issues which we have required TVA to address as part of the licensing action for Sequoyah Unit 2. These items include: (1) the potential for inadvertent steam or fog inerting of the lower compartment of the containment and the subsequent potential for combustion phenomena producing a transition to detonation, and (2) the effects of a postulated continuous burning in the ice condenser region of the containment. The information developed to date regarding these items provides the staff with reasonable assurance that Sequoyah Unit 2 may be safely operated. Consistent with requirements imposed in the Sequoyah Unit 1 license and proposed for the McGuire Unit 1 license, certain additional information must be submitted for the Commission to conclude by January 31, 1982 that the hydrogen control system will function in a manner that provides adequate safety margins.

Lower Compartment Inerting

Inerting or rendering noncombustible a hydrogen-air mixture in the lower compartment with the addition of steam or fog is a general concern for several reasons. First, any mechanism which prevents combustion in the lower compartment increases the likelihood of a constant volume combustion process in the upper compartment of the containment Combustion in either the lower compartment or the ice condenser compartment is not constant volume; hot gases can expand into the larger volume above these compartments. As reported previously in Supplement 4 to the Sequoyah SER, the base case analysis performed by TVA for the S_2D transient showed virtually all the hydrogen burning to occur in the wer compartment. Since the lower compartment is only approximately 1/4 of the total containment volume, combustion in the lower compartment involves

a smaller quantity of hydrogen and allows for the expansion of the hot gases into the ice bed and the upper containment, thereby reducing the pressure.

Another reason for concern over inadvertent inerting of the lower compartment is that a highly enriched hydrogen-air mixture may enter the upper plenum of the ice condenser due to steam condensation in the ice bed. However, for this to occur, it would be necessary to have coincident large hydrogen and steam fractions in the lower compartment. If an enriched hydrogen mixture exists in the ice bed or in the upper plenum, there is an increased probability for the combustion phenomena to include a transition to detonation. This concern originated in the staff and has been emphasized by Sandia National Laboratory as previously discussed in Supplement 4 to the SER.

The reason that additional attention to this topic is warranted is twofold. First, the original base-case analysis of the S_2D transient was truncated at a point in time where approximately 80% of the core cladding had reacted. There was no modeling of the core recovery phase of the transient. It has since been postulated that the core recovery by injection of water could result in large steam and hydrogen release rates and that these releases could produce the lower compartment inerting conditions discussed above. Thus, while the original analysis shows the lower compartment steam concentration to be less than 30 percent over the period of interest, revised analyses might result in a substantially higher fraction.

Second, there is a possibility that ignition of hydrogen mixtures in the lower compartment may be suppressed by the presence of a water fog. A fog is a suspension of liquid water in the form of droplets in the atmosphere. A fog can be created by bulk condensation of steam and the formation of droplets at nucleation sites. It is known that a water fog, comprised of appropriate size droplets, will suppress the pressure and temperature following combustion. There also is evidence that a sufficient fog density may render normally combustible mixtures nonflammable.

The presence of a water fog has been conjectured by several consultants as the explanation for the anomalous results in two igniter tests previously discussed in Supplement 4. These tests, conducted by Lawrence Livermore National Laboratory (LLNL) and identified as tests 34 and 43, involved the initial introduction of steam to a 50 percent concentration and operation of the glow plug with the steam concentration allowed to fall by condensation on the test vessel walls. As previously noted in Supplement 4, combustion did not occur when expected, although a slight pressure rise was recorded for test 34 when a circulating fan was activated. Continued testing of the glow plug igniter in high steam fraction environments is underway and it is the current position of LLNL that the presence of fog is insufficient as the sole explanation for the failure to achieve ignition under the test conditions. LLNL has noted that tests involving steam addition other than tests 34 and 43, although at an initially lower steam concentration, were performed using the same procedure and successful ignition was achieved. LLNL, therefore, concludes that if a fog of undetermined density and drop sizes existed in the unsuccessful ignition tests at 50 percent steam, it most probably also existed in the successful tests at 40 percent steam. Visual observation of nonburning tests with steam injection did confirm that optical obscuration does occur and persists for some time after steam injection was terminated.

The staff has concluded that the igniter tests performed at LLNL were more likely to produce fogging as compared to the expected containment-wide conditions in the Sequoyah Nuclear Plant, due to the test procedure and configuration. When the various regions of the Sequoyah plant are considered, the LLNL test configuration most closely models the lower compartment.

Since fogging appears to be due to a wall cooling effect, an important parameter is the ratio of wall surface area to atmosphere volume. A comparison of these ratios between the LLNL test vessel and the Sequoyah plant, considering the surface area of the containment shell, shows that the LLNL test vessel has a much greater ratio of surface area to volume. Thus, the potential and effects of fogging would logically be expected to be greater inside the small vessel than in the Sequoyah containment. Furthermore, the staff presently does not believe that the consequences of inerting the lower compartment are necessarily severe, i.e., not severe enough to cause breach of containment. For the moderate release rates of hydrogen associated with small-break, loss-of-coolant accidents, i.e., on the order of 30 lb/min, it appears that burning can safely occur in other portions of the containment without creating unacceptably high pressures. Further analysis is needed to confirm the effects of steam and fog inerting, but the staff believes these may reasonably be deferred until final disposition of the proposed IDIS in January 1982. As will be discussed later, the information derived from the views expressed by Duke's consultants on McGuire indicate that the upper plenum igniters will result in the controlled combustion of hydrogen by deflagration and not detonation even in the cases in which the lower compartment may become inerted.

TVA, at our request, has considered the potential for inerting the lower compartment with either steam or fog. In order to address the issue of steam inerting, TVA has committed to extend the base S_2D scenario to include the recovery phase of the transient. The results of this analysis will be provided as part of the October 1981 submittal by TVA on the permanent hydrogen mitigation system. It is also TVA's preliminary judgment that neither a significant release of hydrogen nor lower compartment steam inerting from boiloff of the water supplied by a safety injection pump would occur following S_2D reflood. The staff's calculations indicate that reflooding without significant hydrogen expulsion is feasible during many phases of the period of core uncovery. Nevertheless, there is a concern that under certain circumstances the hydrogen already accumulated as a bubble in the reactor vessel may be rapidly expelled during reflooding together with sufficient steam for temporary inerting. Because of the limited circumstances under which this situation seems to exist, the staff concludes that final resolution of this matter may reasonably be deferred until January 31, 1982.

Regarding the potential for fog formation, TVA has provided reasoning similar to that of the staff, i.e., the test vessel does not properly scale the surface area to volume ratio. Additionally, TVA has noted that during a small-break degraded core accident with continuous superheated steam and hot hydrogen injection, there is less tendency for fog formation. This is due to the fact that additional sensible heat must be removed from the atmosphere before condensation can occur.

TVA also identified another mechanism, other than the wall cooling effect, by which fog may be formed. This is at the discharge of the air return fan where

colder upper compartment air is injected into the warmer lower compartment. TVA has argued that in this situation the cooler air from the upper compartment would tend to sink to the floor, placing the cold air/warm air interface away from the igniters and low in the volume where any fog would rain out to water on the floor.

Furthermore, TVA has concluded that, given the hydrogen release rates for the base case S_2D scenario, inerting of the lower compartment is unimportant since burning in the ice condenser upper plenum would deplete the hydrogen with acceptable consequences.

The staff concludes that more information is needed to satisfactorily explain the role that water fogging played in some of the LLNL igniter tests. Regardless of the outcome of this ongoing investigation, we will require that the applicant provide additional information to justify the analytical assumptions regarding fog effects on igniter performance prior to concluding our review of the proposed ignition system. This additional information must quantitatively assess the formation of a fog and its effect on performance of the ignition system.

The Sandia National Laboratory (SNL) concern over inerting of the lower compartment is that if this occurs coincident with a moderately high hydrogen fraction (approximately 9 v/o) then a potentially detonable mixture would appear in the upper ice bed or upper plenum region. It is the position of SNL that the effect of inerting in this situation could lead to conditions where combustion, due to the placement of upper plenum igniters, might result in a transition to detonation. The general issue of locating igniters in the ice condenser upper plenum was previously discussed in Supplement 4. Originally there was concern by some consultants that the igniters themselves could initiate a detonation if the hydrogen concentration exceeded a limit value of approximately 18 v/o. Since that time, the staff has concluded that the proposed glow plug igniter by itself is unlikely to initiate a detonation.

Further developments relating to this issue have occurred since issuance of Supplement 4 based on the Sandia citation of recent experimental combustion data which exhibited large pressures. The significance of these test data is that obstacles in the path of a flame front tended to accelerate the combustion process dramatically to the point where measured pressures were much greater than would be expected for combustion of a similar mixture in an unobstructed chamber. The scale of the experimental apparatus (10m x 2.5m) was also larger than much of that used as the basis for detonation theory. It is the Sandia postulate that these experimental data show that the run-up distance required for a transition to detonation can be markedly decreased in the presence of obstacles. Sandia further contends that obstructions in the ice condenser region of the plant could serve the same function. Thus, in order to avoid the possibility of unexpectedly large pressures, Sandia's recommendation is to try to avoid ignition in the ice condenser region. Sandia, at this point, makes no claims that transition to detonation is likely; rather, Sandia argues that the risk imposed by the upper plenum igniters is higher than their benefit. An additional item which the recent experimentation sought to address was the potential for detonation initiation by a strong turbulent jet. This phenomenon has also been identified by Sandia as a possible mechanism for producing a detonation or large overpressures in the ice condenser region.

The staff met with Sandia in March 1981 in an attempt to better understand its position and the details of the experimental data. Sandia, at this meeting, acknowledged that there were differences between the experiments and conditions inside the ice condenser, the most notable being that the experiments were conducted with stoichiometric mixtures of propane and methane. A stoichiometric mixture of hydrogen and air contains approximately 29.5 v/o hydrogen. Since the igniter system is designed to combust hydrogen at much lower concentrations, the staff inquired of Sandia whether there was any similar experimental evidence more closely related to likely containment conditions. Sandia acknowledged that no experiments have been conducted with 8-12 v/o hydrogen mixtures and, therefore, it is not known to what extent off-stoichiometric conditions would influence flame propagation.

As a part of the staff's licensing review for the McGuire nuclear power plant, these items were discussed with the applicant's (Duke Power Company) combustion consultants and discussed on the record during the hearings held in connection with the McGuire proceedings in February and March 1981. Their response after having toured the plant was that the geometry and flow conditions inside the ice condenser region of the plant simply are not conducive to producing a transition to detonation. The Duke consultant's view was that, for an S_2D type scenario, the upper plenum igniters would ignite the mixture as it first becomes flammable, then as a richer mixture is vented to the upper plenum, the igniters will produce a horizontal standing flame. If the mixture is further enriched, then the flame will propagate downward into the ice bed until it settles to an equilibrium point where sufficient steam has been condensed. In the opinion of the Duke consultants, even if an inerted mixture with a high hydrogen concentration were introduced to the ice bed, the flame front would simply propagate to an equilibrium elevation where sufficient steam was condensed to support combustion. The flame propagation will not allow the hydrogen steam-air-mixture to dry out to the point where detonable mixtures would develop.

Continuous Burning

The second general issue that was identified in our ongoing review was the item described as continuous burning in the upper ice condenser. In Supplements 3 and 4 to the SER, we described the CLASIX analyses which showed, for the base case, that virtually all combustion took place in the lower compartment. We also commented on the advantages of combustion in that region, e.g., avoiding constant volume explosions, and burning of smaller quantities of hydrogen.

However, as a part of the review of the hydrogen mitigation system installed in the McGuire plant, the Duke Power Company has stated that for hydrogen releases calculated for the S_2D scenario it is likely that continuous burning will occur at the top of the ice bed. Since the hydrogen mitigation system at the McGuire plant is very similar to that installed at Sequoyah, the staff requested that TVA address the likelihood and consequences of continuous burning in the ice condenser upper plenum.

TVA's response to this request was that burning in the upper plenum has been and is considered to be a realistic condition in the containment burning response spectrum. TVA further states that the pattern of burning or the continuous nature of the burn would depend on the assumptions made regarding flammability limits. TVA concludes that continuous burning in the upper plenum bounds one

end of the possible burning conditions and that repeated lower compartment burns bound the other end.

The staff surmises that the reason significant burning does not occur in the upper plenum in the CLASIX analyses as reported in Supplements 3 and 4 is that the preliminary containment model included the upper plenum as part of the upper compartment volume. Thus, while the upper plenum may have a higher hydrogen concentration, it is in effect diluted by adding in the upper compartment volume and composition.

A recent revised base-case CLASIX analysis using a separate volume to model the upper plenum does indeed show that semicontinuous burns would occur there. This case produced a peak containment pressure of approximately 26.3 psia, compared to 28.5 psia for the previously reported base case.

The staff has considered this matter and concludes that continuous or near-continuous burning in the upper plenum is likely to produce lower pressure consequences for containment than burning in the upper or lower compartments. Burning in the upper plenum of the ice condenser has the advantages of: (1) burning a smaller quantity of hydrogen, since the upper plenum is a relatively small volume (approximately 50,000 ft^3); (2) venting the atmosphere to the large downsteam volume of the upper compartment where it is cooled by the containment sprays; and (3) burning in a region which is distant from most of the essential equipment.

While the staff believes that there are advantages to the condition of continuous burning in the upper ice condenser section of the containment, there is also the necessity to address the temperature effects of sustained burning in that region. The primary concern over temperature effects is the impact on insulating material in the ice condenser region. As we discussed in Supplement 4 to the SER, the design of the ice condenser utilizes polyurethane foam insulation. When exposed to an external heat source, the polyurethane foam behind the wall panel will undergo pyrolysis at a rate dependent on the foam temperature.

Pyrolysis or decomposition of the foam produces volatile gases with a heat of combustion of about 12,000 Btus per pound foam. Since the ice condenser contains approximately 30,000 lbs of foam, it is apparent that large-scale decomposition of the foam is unacceptable. We have, therefore, requested that TVA evaluate the thermal response of the polyurethane foam for the condition where continuous burning occurs in the ice bed. TVA in response to our query has referenced the analysis performed by Duke to answer the same question on the McGuire plant. Since the construction of the ice condenser at Sequoyah is essentially the same as at McGuire, TVA concludes and the staff concurs that the analysis should be equally valid.

The Duke analysis assumed a standing flame in the ice bed which persists for 45 minutes, corresponding to the approximate duration of hydrogen releases. The bulk of the foam would be separated from the flame by a thermal resistance path consisting of the two air handling ducts, the downcomer section and return section. At the joint connections between ducts, the foam is closer to the postulated flame in that it is separated by layers of thin metal and other insulating material, but this is a small fraction of the total mass of foam. Much of it was considered to pyrolyze in the Duke analysis. A heat transfer

analysis was performed considering the effects of radiation, convection, and conduction. The Duke evaluation considered that as a result of heat transfer, approximately 250 lbs of foam could decompose. The gases thus produced would have a total heat of combustion of 3×10^6 Btu; by comparison to the 80×10^6 Btu associated with the hydrogen burning, this incremental energy addition is inconsequential from a containment integrity standpoint.

The staff has reviewed the analysis performed by Duke and concluded that pyrolysis of foam does not constitute any undue threat to containment integrity.

The staff has also performed confirmatory calculations and verified that the mass of foam which undergoes pyrolysis is insufficient to threaten containment integrity. These preliminary calculations should, however, be developed as part of the further studies of the igniter system and the containment response. The staff will require TVA to submit analyses addressing the effects of continuous burning in the ice condenser region of the Sequoyah plant. The analysis should include further consideration of air ingestion to the volume containing foam and two dimensional heat transfer effects.

The staff has determined as a result of reviewing this issue that it would be prudent to trip the air handling unit fans when the igniters are actuated. The air handling unit fans take suction from the upper plenum and circulate the air through the wall panel ducts. Removing power from the ice condenser air handling units will eliminate forced circulation of potentially hot combustion products, in the event continuous burning occurred in the upper plenum, which would contribute to heatup of the foam. Furthermore, tripping of the air handling units would reduce the potential for ingestion of hydrogen into the duct system.

TVA has evaluated the merit of this recommendation and is modifying its emergency operating instructions for Units 1 and 2 to remove power from the air handling units during potential hydrogen combustion events.

Prior to concluding the review of the proposed IDIS in January 1982, we have also required that TVA test the igniter assemblies to demonstrate their performance in a continuous burning environment since upper plenum igniters may be exposed to such conditions.

Survivability of Essential Equipment During and After a Hydrogen Burn Event

In response to staff requests relating to the survivability of certain essential equipment during a hydrogen burn event, the licensee provided submittals dated December 11, 15, 17, and 24, 1980 and January 22, 1981. These submittals provided information relating to TVA's program for controlling hydrogen subsequent to a degraded core LOCA event, the results of testing conducted, and a list of essential safety-related equipment. The equipment necessary to assure functionality of the interim distributed ignition system (IDIS) and to validate the analytical predictions regarding precluding breach of containment are specifically the igniters, air return fans, containment sprays, and related power and control cables. The first two items are contained on TVA's list. The third item, containment sprays, contains only piping and check valves in containment.

Inside containment the following minimum systems are required to maintain the degraded core in a stable safe shutdown condition following H_2 burn:

1. RCS for ECC function.

2. RCS instruments for pressure and temperature.

3. Wiring and power cabling associated with these systems and components.

The list of essential equipment inside containment associated with these systems needed to assure safe shutdown and containment integrity is:

1. Steam generator, pressurizer, and sump level transmitters.

2. Air return fan RTDs.

3. Hot leg RTDs.

4. Gasket and seals for flanges, electrical boxes, air locks, and the equipment hatch.

5. Hydrogen igniters.

6. Electrical penetrations.

7. Containment isolation valves including hydrogen sample valves.

8. Wrapped cable.

9. Exposed cable - core exit thermocouples.

10. Exposed cable cold leg RTDs.

11. Junction boxes.

12. Reactor coolant system pressure indicator.

13. Related power and control cables.

In addition, there are piping runs in containment associated with other safe shutdown systems, but no equipment other than the types included in the foregoing list. TVA's list of essential equipment to assure safe shutdown includes all items on the staff's list except the reactor coolant system pressure indicator. Based upon discussions with TVA, we understand that the pressure indicators will survive the effects of hydrogen ignition.

During our review we have considered the need to ensure the functionality of the hydrogen recombiners for long-term hydrogen control. On May 15, 1981, TVA provided an analysis on their survivability which states that the recombiners will survive the degraded core scenario and be functional to mitigate a long-term hydrogen production from radiolysis and corrosion. The staff agrees that the recombiners would survive and remain functional.

As discussed previously in SER Supplement 4 and in Staff testimony before the ASLB as a part of the Operating License Hearing for W.B. McGuire Units 1 and 2, the survivability of essential equipment has been the focus of analytical and experimental studies and onsite inspections by the licensee and the staff. The preliminary results of these studies are that for typical instruments (a Barton transmitter), both staff and applicant estimate the temperatures reached by the component to be less than 320°F. This temperature is not significantly different than the maximum temperatures calculated for design basis accidents for McGuire (327°F for MSLB) but could exist for a somewhat larger time interval. Additionally, the licensee has conducted scoping tests at the FENWAL facility on selected equipment. Although the FENWAL tests, conducted in a relatively small chamber, have not yet been directly related to the containment environment, much has been learned from the testing conducted at FENWAL with regard to the hydrogen control system and the expected containment environment. Failure modes as well as ways of providing protection for exposed equipment have been identified. The FENWAL tests generally indicate that the selected equipment did survive successive hydrogen burns with little or no damage, with two exceptions. The exceptions were unprotected thermocouple wires (teflon insulated) and soldered joints. These failure types are not directly applicable to Sequoyah.

The staff has requested the licensee to provide improved means of quantifying thermal effects on equipment survivability by June 1, 1981. The request includes improved calculational methods for containment temperatures, confirmatory tests on selected equipment exposed to hydrogen burns and new calculations to predict differences between expected equipment temperature environments and containment temperatures. The present version of the CLASIX code does not include heat sinks nor does it model separately the upper region of the ice condenser. The licensee has, however, begun refinements to CLASIX to remedy these two deficiencies and has preliminarily reported that the new CLASIX calculations, which take into account the structural heat sinks and model the upper plenum, predict 2 (two) burns in the lower compartment and about 30 to 40 burns in the upper plenum of the ice condenser. These analyses showed temperatures considerably lower than those previously predicted for the lower compartment where the majority of the instruments are located. The TVA-revised CLASIX analyses also show an insignificant calculated temperature increase for the upper compartment atmosphere. TVA has also performed a scoping test at the Singleton Laboratories on the core exit themocouple cables and the reactor coolant system RTD cables. In this test the cable was baked in an oven at about 1300°F for 30 seconds. The result of the test showed that the cable survived the test. Both the new calculation and the test results will be submitted to the staff by June 1, 1981. The staff will review and evaluate the information when provided.

In summary, based upon the S_2D accident scenario, the staff concludes that, although the need exists to develop additional confirmatory information relating to the equipment survivability, operation of the IDIS until January 31, 1982 is acceptable. This conclusion is based on our judgment that (1) the conditions imposed by a possible hydrogen burn will not be aggravated by the operation of the IDIS; (2) it is likely that equipment important to maintain containment integrity and to maintain a degraded core in a stable shutdown condition will be able to survive the effects of a hydrogen burn. Moreover, as concluded previously, the S_2D scenario and other H_2 generating scenarios are very low

probability events--events which might reasonably be anticipated during this limited period would lead to less demanding service conditions for this equipment.

Accordingly, we find the proposed IDIS acceptable for Sequoyah Unit 2. However, we recommend that the operating license for Unit 2 be conditioned in the same manner that the Unit 1 license was conditioned. That is, further information must be submitted by TVA for the NRC to conclude by January 31, 1982 that the chosen hydrogen control system will function in a manner that provides adequate safety margins.

II.D.1 Relief and Safety Valve Test Requirements

Position

Pressurized-water reactor and boiling-water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

Discussion

In TVA's letters of December 19, 1980 and May 14, 1981, the applicant referenced the EPRI PWR Relief and Safety Valve Test Program as its response to this requirement for Unit 2. TVA has reviewed the performance of the block valves during the recent EPRI test program concerning Pressurizer Operator Relief Valves (PORV) reliability. Although PORV block valves were not part of the EPRI test program, some information was generated concerning the performance characteristics of certain valves.

The PORV block valves for the Sequoyah Nuclear Plant unit 2 are manufactured by Velan Valve Corporation; and this same type of Velan block valve, was used during the recent PORV testing conducted by EPRI at Marshall test center. These Velan block valves performed as expected, without leakage and without operational failures. The Dresser and Target Rock PORV valves that recently failed in the EPRI tests are not used in Sequoyah. The NRC has established July 1, 1982 as the date for verification of block valve functionability. The license will be conditioned to require that TVA provide evidence supported by test that the block or isolation valves between the pressurizer and each power-operated relief valve can be operated, closed, and opened for all fluid conditions expected under operating and accident conditions.

We find TVA's commitment to follow the EPRI PWR RV/SV test program for Sequoyah Unit 2 to be acceptable to meet full-power requirements. The Unit 1 license is conditioned to complete this item by July 1, 1981. We will amend the Unit 1 license to conform with the new requirements of NUREG-0737.

II.E.1.1 Auxiliary Feedwater System Evaluation

Position

The Office of Nuclear Reactor Regulation is requiring reevaluation of the auxiliary feedwater (AFW) systems for all PWR operating plant licensees and operating license applications. This action includes:

(1) Perform a simplified AFW system reliability analysis that uses event-tree and fault-tree logic techniques to determine the potential for AFW system failure under various loss of main feedwater transient conditions. Particular emphasis is given to determining potential failures that could result from human errors, common causes, single-point vulnerabilities, and test and maintenance outages;

(2) Perform a deterministic review of the AFW system using the acceptance criteria of Standard Review Plan Section 10.4.9 and associated Branch Technical Position ASB 10-1 as principal guidance; and

(3) Reevaluate the AFW system flow rate design bases and criteria.

Discussion

In Supplement No. 2 to the SER, we concluded that Sequoyah Units 1 and 2 meet this item. However, a license condition is required for Unit 2, as was the case for Unit 1, requiring auxiliary feedwater pump endurance tests. The tests for Unit 2 will be conditioned in the same manner as Unit 1.

II.E.1.2 Auxiliary Feedwater System Automatic Initiation and Flow Indication

Part 1: Auxiliary Feedwater System Automatic Initiation

Position

Consistent with satisfying the requirements of General Design Criterion 20 of Appendix A to 10 CFR Part 50 with respect to the timely initiation of the auxiliary feedwater system (AFWS), the following requirements shall be implemented in the short term:

(1) The design shall provide for the automatic initiation of the AFWS.

(2) The automatic initiation signals and circuits shall be designed so that a single failure will not result in the loss of AFWS function.

(3) Testability of the initiating signals and circuits shall be a feature of the design.

(4) The initiating signals and circuits shall be powered from the emergency buses.

(5) Manual capability to initiate the AFWS from the control room shall be retained and shall be implemented so that a single failure in the manual circuits will not result in the loss of system function.

(6) The ac motor-driven pumps and valves in the AFWS shall be included in the automatic actuation (simultaneous and/or sequential) of the loads onto the emergency buses.

(7) The automatic initiating signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the AFWS from the control room.

In the long term, the automatic initiation signals and circuits shall be upgraded in accordance with safety-grade requirements.

Part 2: Auxiliary Feedwater System Flowrate Indication

Position

Consistent with satisfying the requirements set forth in General Design Criterion 13 to provide capability in the control room to ascertain the actual performance of the AFWS when it is called to perform its intended function, the following requirements shall be implemented:

1. Safety-grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room.

2. The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity requirements of the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9.

Discussion

A license condition exists for Unit 1 which states that TVA will upgrade the indication of auxiliary feedwater flow to each steam generator to safety grade quality. The issuance of NUREG-0737 has revised the requirements for flow indication such that Sequoyah Units 1 and 2 now fully comply with this item with no further modifications. No license condition is needed for Unit 2.

II.E.4.2 Containment Isolation Dependability

Position

(1) Containment isolation system designs shall comply with the recommendations of Standard Review Plan Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).

(2) All plant personnel shall give careful consideration to the definition of essential and nonessential systems, identify each system determined to be essential, identify each system determined to be nonessential, describe the basis for selection of each essential system, modify their containment isolation designs accordingly, and report the results of the reevaluation to the NRC.

(3) All nonessential systems shall be automatically isolated by the containment isolation signal.

(4) The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.

(5) The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

(6) Containment purge valves that do not satisfy the operability criteria set forth in Branch Technical Position CSB 6-4 or the Staff Interim Position of October 23, 1979 must be sealed closed as defined in SRP Section 6.2.4, item II.3.f, during operational conditions 1, 2, 3, and 4. Furthermore, these valves must be verified to be closed at least every 31 days. (A copy of the Staff Interim Position is enclosed as Attachment 1.)

(7) Containment purge and vent isolation valves must close on a high radiation signal.

Discussion

In response to the requirement stated in NUREG-0737, TVA provided additional information on the Sequoyah containment pressure setpoint. The Sequoyah containment pressure high setpoint is required to be less than or equal to 1.54 psig by Technical Specification 3.3.2.1, "Engineering Safety Features Actuation System Instrumentation." It is more than 1 psig above the highest primary containment internal pressure allowed by Technical Specification 3.6.1.4, "Containment Internal Pressure"; however, TVA believes that the present containment pressure high setpoint is adequate. The reasons are stated below.

The containment pressure high channel actuates safety injection, turbine trip, and feedwater isolation. Phase "A" containment isolation is actuated from the safety injection logic. Reducing the containment pressure high setpoint increases the potential not only for inadvertent containment isolation but also inadvertent safety injection and feedwater isolation.

Adequate protection is already provided to prevent the release of radioactive materials following an accident. Containment ventilation isolation is initiated by diverse signals, including all safety injection actuation channels including low pressurizer pressure, high gaseous or particulate activity in containment, and high activity in the purge air exhaust.

The containment pressure high and high-high setpoints and low pressurizer pressure setpoints are reached almost immediately in large loss-of-coolant accidents (LOCA). Lowering the containment pressure high setpoint will not provide any additional safety margin to the accident analyses because of the speed at which the containment pressure rises for large LOCAs.

Two cases for small LOCAs are considered: those for which the charging system can maintain reactor coolant system inventory and those that cannot. In the first case, core uncovery will not occur and the radioactivity released is limited to the material contained in the coolant. Containment vent isolation will occur. The setpoint for the ventilation isolation signals are set to prevent releases exceeding 10 CFR Part 20 limits (normal release limits). Lowering the containment pressure high setpoint will not provide any significant additional safety margin.

In the second case, safety injection will always occur much sooner than core uncovery. Since phase "A" isolation occurs on safety injection, radioactivity releases prior to isolation are limited to material contained in the coolant. Containment vent isolation will occur. Lowering the containment pressure high setpoint will not provide any significant additional safety margins.

Based on the reasons set forth above, the staff agrees that the present containment pressure high setpoint of 1.54 psig is adequate. Reduction of this setpoint would provide no significant additional safety margin.

The applicant has committed in the letter of May 26, 1981 to limit the opening of the containment purge valves to a maximum of 50° to meet the requirements of the "Interim Position" of II.E.4.2 of NUREG-0737. This is an acceptable interim resolution until long-term operability is demonstrated.

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

Position

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

Discussion

In Supplement Nos. 1 and 2, we stated that TVA would provide the reactor vessel water level instrumentation system by January 1, 1982 and would provide a subcooling monitor prior to operation in order to provide an unambiguous, easy-to-interpret indication of ICC.

NUREG-0737 gave further clarification of item II.F.2 by adding Attachment 1, "Design Qualification Criteria for Pressurized-Water Reactor Incore Thermocouples." TVA responded to this attachment in their letter of April 13, 1981. The licensee will submit proposed modifications by June 1, 1981 to the ICC monitoring system in response to Attachment 1. The staff's position is as follows:

1. The plant computer readout of the incore thermocouples are considered the primary display.

2. The backup display should be replaced by an indicator capable of temperature indication over the range of 200°F to 2300°F.

3. The backup display should have the capability to read 16 thermocouples (T/C) (4 per quadrant). The input to the computer of this group of thermocouples should be through fully qualified isolation devices. The isolation devices may be implemented by the use of manual switches, electronic or electromechanical multiplexers, or analog to digital converters upstream of the plant computer.

4. The thermocouples to the backup display should be separated from the balance of the computer input thermocouples in accordance with Regulatory Guide 1.75.

5. The backup display, T/C wiring, and reference T/C junction controls should be upgraded to seismic (Regulatory Guide 1.100) and environmental (Regulatory Guide 1.89) qualification requirements exclusive of those portions internal to the reactor vessel.

6. The backup system should be operable from a Class 1E power source or a suitable battery backed instrument bus.

This item is unresolved pending the results of our review of TVA's submittal. Implementation of a system satisfactory to the staff will be required by January 1, 1982 unless a good cause is provided for a delay in schedule.

II.K.2 Orders on B&W Plants

II.K.2.13 Effect of High-Pressure Injection on Vessel Integrity for Small-Break LOCA With No Auxiliary Feedwater

Position

A detailed analysis shall be performed of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater.

Discussion

This item was satisfactorily resolved in Supplement No. 1 to the SER for both units. TVA letters in response to the item are dated December 19, 1980 and April 3, 1981.

II.K.2.17 Potential for Voiding in the RCS During Transients

Position

Analyze the potential for voiding in the reactor coolant system (RCS) during anticipated transients.

Discussion

The Westinghouse Owners' Group (TVA is a member) is addressing this item. A report describing the results of this effort will be provided by January 1, 1982. For further information, see TVA letters dated December 19, 1980 and April 3, 1981. This is acceptable to the staff.

II.K.2.19 Sequential Auxiliary Feedwater Flow Analysis

Position

Provide a benchmark analysis of sequential auxiliary feedwater (AFW) flow to the steam generators following a loss of main feedwater.

Discussion

TVA committed to meeting this item in their letters dated December 19, 1980 and April 3, 1981. TVA states that the Westinghouse Owners' Group (TVA is a member) is addressing this matter and they will provide a report by July 1, 1982. This is satisfactory to the staff.

II.K.3 Final Recommendations of B&O Task Force

II.K.3.1 Installation and Testing of Automatic Power-Operated Relief Valve Isolation System

Position

All PWR licensees should provide a system that uses the PORV block valve to protect against a small-break loss-of-coolant accident. This system will automatically cause the block valve to close when the reactor coolant system pressure decays after the PORV has opened. Justification should be provided to assure that failure of this system would not decrease overall safety by aggravating plant transients and accidents.

Each licensee shall perform a confirmatory test of the automatic block valve closure system following installation.

Discussion

TVA committed to meeting this item in their letters dated December 19, 1980 and January 7, 1981. Staff implementation is delayed pending review of the results of Item II.K.3.2.

II.K.3.2 Report on Overall Safety Effect of Power-Operated Relief Valve Isolation System

Position

(1) The licensee should submit a report for staff review documenting the various actions taken to decrease the probability of a small-break loss-of-coolant accident (LOCA) caused by a stuck-open power-operated relief valve (PORV) and show how those actions constitute sufficient improvements in reactor safety.

(2) Safety valve failure rates based on past history of the operating plants designed by the specific nuclear steam supply system (NSSS) vendor should be included in the report submitted in response to (1) above.

Discussion

TVA committed to meeting this item in letters dated December 19, 1980, and January 7 and April 3, 1981. TVA states that the Westinghouse Owners' Group submitted a report to address the NRC concerns on this item in compliance with the requirement (WCAP-9804, dated April 1981).

II.K.3.3 Reporting Safety Valve and Relief Valve Failures and Challenges

Position

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report.

This requirement shall be met before issuance of a full-power license.

Discussion

By letters dated July 18, 1980 and April 3, 1981, TVA submitted information documenting compliance with this requirement for Units 1 and 2.

II.K.3.5 Automatic Trip of Reactor Coolant Pumps During Loss-of-Coolant Accident

Position

Tripping of the reactor coolant pumps in case of a loss-of-coolant accident (LOCA) is not an ideal solution. Licensees should consider other solutions to the small-break LOCA problem (for example, an increase in safety injection flow rate). In the meantime, until better solution is found, the reactor coolant pumps should be tripped automatically in case of a small-break LOCA. The signals designated to initiate the pump trip are discussed in NUREG-0623.

Discussion

Westinghouse has prepared and submitted a design modification for the automatic RCP trip to the NRC. If required, TVA committed in their letters of December 12, 1980 and April 3, 1981 to any modification prior to startup at the first refueling outage. This is satisfactory to the staff. If any necessary modifications are required they are to be implemented by March 1982.

II.K.3.9 Proportional Integral Derivative Controller Modification

Position

Modify the proportional integral derivative controller as recommended by Westinghouse.

Discussion

TVA stated in their letters of July 7, 1980 and December 10, 1980 that they comply with our requirements. The staff agrees that this requirement is satisfied.

II.K.3.10 Proposed Anticipatory Trip Modification

Position

The anticipatory trip modification proposed by some licensees to confine the range of use to high-power levels should not be made until it has been shown on a plant-by-plant basis that the probability of a small-break loss-of-coolant

accident (LOCA) resulting from a stuck-open power-operated relief valve (PORV) is substantially unaffected by the modification.

Discussion

In letters dated July 18, 1980 and April 3, 1981, TVA stated that is has not proposed this modification; however, on May 14, 1981, TVA proposed to delete the reactor trip on turbine trip below 50 percent power. This is under review by the staff. The staff accepted the proposed changes for both units based on the computed predictions for Sequoyah Units 1 and 2, and the test results obtained from another similar licensed plant. It is concluded that the operation of the plant at 50 percent rated power or below without the anticipatory reactor trip tie to the turbine trip will not significantly change the probability of a small break LOCA due to a stuck open PORV. The requirements of this item are satisfied.

II.K.3.11 Justifying Use of Certain PORVs

Position

Justification is needed to use CCI supplied PORVs.

Discussion

In letters dated July 3, 1980 and April 3, 1981, TVA stated that Sequoyah Units 1 and 2 are not supplied by CCI, and therefore no modifications are required.

II.K.3.12 Anticipatory Trip on Turbine Trip

Position

Licensees with Westinghouse-designed operating plants should confirm that their plants have an anticipatory reactor trip upon turbine trip. The licensee of any plant where this trip is not present should provide a conceptual design and evaluation for the installation of this trip.

Discussion

In letters dated July 18, 1980 and April 3, 1981, TVA confirmed that there is an anticipatory trip on turbine trip at Sequoyah Units 1 and 2 which satisfies our requirement.

II.K.3.17 Report on Outages of Emergency Core Cooling System Licensee Report and Proposed Technical Specification Changes

Position

Several components of the emergency core cooling (ECC) systems are permitted by Technical Specifications to have substantial outage times (e.g., 72 hours for one diesel generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

Discussion

In their letters of December 19, 1980 and April 3, 1981, TVA submitted a plan for gathering cumulative outage times for ECC equipment and to submit this data. This requirement has been satisfied.

II.K.3.25 Effect of Loss of Alternating Current Power on Pump Seals

Position

The licensees should determine, on a plant-specific basis by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating current (ac) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

Discussion

The TVA letters of December 19, 1980 and April 3, 1981 stated that Sequoyah presently supplies emergency power to the component cooling water pumps through automatic sequencing on to the diesel generators after a loss of offsite power. In view of this sequencing, TVA is in compliance with this requirement.

II.K.3.30 Revised Small-Break Loss-of-Coolant Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K

Position

The analysis methods used by nuclear steam supply system (NSSS) vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analyses for compliance with Appendix K to 10 CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities. (See Discussion under Section II.K.3.31.)

II.K.3.31 Plant-Specific Calculations

Position

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs) as described in item II.K.3.30 to show compliance with 10 CFR 50.46 should be submitted for NRC approval by all licensees.

Discussion for II.K.3.30 and II.K.3.31

The Westinghouse Owners' Group has responded to requirement II.K.3.30. The group set forth a justification for the acceptability of the existing small-break LOCA models. Additional information for model justification is scheduled for January 1, 1982. Pending a resolution of II.K.3.30, the need for plant-specific analysis is dependent on the outcome of the LOCA models. A plant-specific analysis is expected to be completed in the required period September 1, 1982. TVA has committed to meet this item in letters dated December 19, 1980 and April 3, 1981.

III. Emergency Preparation and Radiation Protection

III.A.1.1 Upgrade Emergency Preparedness

Position

Provide an emergency response plan in substantial compliance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants" (which may be modified after May 13, 1980 based on public comments), except that only a description of and completion schedule for the means for providing prompt notification to the population (Appendix 3), the staffing for emergencies in addition to that already required (Table B.1), and an upgraded meteorological program (Appendix 2) need be provided. NRC will give substantial weight to FEMA findings on offsite plans in judging the adequacy against NUREG-0654. Perform an emergency response exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations.

Discussion

Based on our review of the revised January 2, 1981 Sequoyah Nuclear Plant Radiological Emergency Plan against the criteria of NUREG-0654, we conclude that the Emergency Preparedness Evaluation Report previously described in Supplement No. 2 to the Sequoyah SER is applicable to the licensing of Sequoyah Unit 2 provided the following deficiencies with respect to the requirements of NUREG-0737 are corrected:

1. In a letter dated July 28, 1980 TVA agreed to provide an interim Emergency Operations Facility (EOF) and to revise the TVA Radiological Emergency Plan to include a description of this facility location, communications, and manning requirements. An interim EOF has been established (see Section H in Appendix E of the SER Supplement No. 2) which is satisfactory to the staff.

2. In a letter dated August 1, 1980, TVA agreed to provide a more detailed writeup of their recovery operations in the next revision of TVA's Emergency Plan, which was due January 1, 1981. An expanded recovery operations section was included in the revised plan which is satisfactory to the staff.

3. In a letter dated August 1, 1980, TVA committed to a prompt notification system having the design objective capability to essentially complete the initial notification of the public within the plume exposure pathway EPZ within 15 minutes. TVA will expedite procurement of equipment and expects to have the system installed and operational by July 1, 1981 (see Section E in Appendix E of SER Supplement No. 2).

4. In a letter dated August 15, 1980, TVA committed to revise their plan to include a summary of shift manning (see Section B in Appendix E of the SER Supplement No. 2) which is satisfactory to the staff.

5. In the letter dated August 15, 1980, TVA committed to specify instrument readings, parameters, and equipment status in the revised Emergency Plan (see Section D in the Appendix E of the SER Supplement No. 2) which is satisfactory to the staff.

6. TVA committed to provide an upgraded Technical Support Center at Sequoyah Nuclear Plant with the capability of providing real-time meteorological data to offsite locations and to provide for the remote interrogation of meteorological data at the Incident Response Center by NRC and other emergency organizations that require it (see Section H in Appendix E of SER Supplement No. 2). Refer to Section III.A.2 for further discussion.

7. TVA has provided information on onsite capability and resources to provide initial and continuing assessment throughout the course of an accident in response to NRC letter dated October 30, 1979, relative to the Lessons Learned Program designated in NUREG-0578 which is satisfactory to the staff. The Radiological Emergency Plan will be revised accordingly.

An evaluation of the State and local emergency response plans around Sequoyah was provided by the Federal Emergency Management Agency (FEMA) by letter dated April 23, 1981 (see attachment).

Based on the FEMA findings and our evaluation, we conclude Sequoyah Unit 2 meets the emergency response plan requirements for a full-power license.

III.A.1.2 Upgrade Emergency Support Facilities

Position

Provide radiation monitoring and ventilation systems, including particulate and charcoal filters, and otherwise increase the radiation protection to the onsite technical support center to assure that personnel in the center will not receive doses in excess of 5 rem to the whole body or 30 rem to the thyroid for the duration of the accident. Provide direct display of plant safety system parameters and call up display of radiological parameters.

For the near-site emergency operations facility, provide shielding against direct radiation, ventilation isolation capability, dedicated communications with the onsite technical support center and direct display of radiological and meteorological parameters.

This requirement shall be met by January 1, 1981, although the safety parameter information requirements will be staged over a longer period of time. (see NUREG-0578, Sections 2.2.2b and 2.2.2.c, and letters of September 27 and November 9, 1979 and April 25, 1980.)

Discussion

TVA will provide a conceptual design description of the emergency support facilities (TSC, OSC, EOF) to the NRC by June 1, 1981.

Implementation of NUREG-0696 recommendations for the upgraded emergency support facilities required for Sequoyah cannot be complete by October 1, 1982. A

Attachment 1

FEDERAL EMERGENCY MANAGEMENT AGENCY

Washington D.C. 20472

April 23, 1981

Mr. Brian K. Grimes
Director Division of Emergency Preparedness
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Grimes:

This responds to your March 10, 1981, request for several findings and determinations. The following information is provided relative to Sequoyah 2.

On August 7, 1980, by letter to Mr. William L. Dircks, FEMA approved the Tennessee Multi-Jurisdictional Radiological Emergency Response Plan site specific for TVA's Sequoyah 1 Nuclear Power Facility, subject to conditions. We have been advised by FEMA Region IV that the State has taken positive action to correct all deficiencies noted in that letter.

As of this date it is our understanding that the public alerting and notification system is the only major deficiency not completely corrected. The State is working with TVA to ensure meeting the FEMA/NRC joint criteria by July 1, 1981. FEMA Region IV is reviewing the State's proposed alerting and notification system to determine if its design meets the criteria of NUREG-0654/FEMA-REP 1, REV. 1.

A review of the Alabama and Georgia State plans and their participation in recent exercises indicate their capability to respond to ingestion pathway (50-mile emergency planning zone) problems from the Sequoyah site.

Based on the above, it appears that State and local authorities in Tennessee, Alabama and Georgia are adequately prepared to cope with an accident at the Sequoyah site. However, as of this time, our approval of the Tennessee plan, site specific for TVA's Sequoyah site, continues to be approved on the condition that by July 1, 1981, the public alerting and notification system meets FEMA/NRC criteria.

I shall keep you advised of any changes regarding the above.

Sincerely yours,

John E. Dickey
Director, Radiological Emergency Preparedness Division, Population Preparedness Office

preliminary schedule shows that the earliest date the necessary equipment could be delivered to the site is August 1982. Since the construction and installation of the equipment would have to be coordinated with scheduled unit outages, the preliminary schedule shows that an estimated operational date for upgraded emergency support facilities is July 7, 1984. A more specific schedule will be available when the detailed conceptual design has been completed. TVA is investigating comparable alternatives to the NUREG-0696 recommendations which will expedite this schedule. These alternatives will be addressed in the conceptual design submittal to be provided in June 1981.

Existing Emergency Support Facilities

The information provided to the NRC on the response facilities for Sequoyah Unit 1 is applicable to Unit 2. This includes the following:

Technical Support Center (TSC)

A description of the TSC is included in the Sequoyah Nuclear Plant Radiological Emergency Plan.

Location of Technical Support Center

The relay room on elevation 732 in the control building is designated as the site Technical Support Center.

This location was chosen for the following reasons:

There is sufficient space available to accommodate up to 25 persons.

The habitability system for this area is the same one provided for the main control room. No added equipment is required. The air supplied to the room is filtered by an ESF system and is monitored for contaminants. Stay times for this area are the same as for the main control room.

The use of the relay room as the technical support center reduces the cost of providing plant parameter information in the technical support center due to the close proximity of the main control room. This also has the advantage of allowing technical support personnel access to plant instrumentation that may not have been considered necessary during design conception of the technical support center.

The technical support center will have a communications system that will allow communication with control room personnel, but, should it fail, the close proximity of the two areas allows for continued communication.

Staffing of the Technical Support Center

In the event that the Sequoyah Emergency Plan is activated, the Technical Support Center will also be activated and manned during routine work hours for the plant staff with the following personnel:

1. Reactor engineer
2. Mechanical test and studies lead engineer
3. Chemical engineer
4. Lead instrument maintenance engineer
5. Lead mechanical maintenance engineer
6. Lead electrical maintenance engineer

In the event that the plan is activated at other than routine work hours, the site emergency director will make arrangements to staff the Technical Support Center with available onsite personnel or call in offsite personnel.

The Technical Support Center will be manned until the Site Emergency Director determines that it is no longer needed.

Reference Materials

The below listed reference materials will be provided in the TSC:

1. Sequoyah Nuclear Plant FSAR
2. Sequoyah Nuclear Plant Technical Specifications
3. Surveillance instructions (selected)
4. Technical instructions (selected)
5. Radiological control instructions
6. Hazard control instructions
7. System operating instructions
8. Radiological Emergency Plan and Implementing Procedures Document
9. Spill prevention control plan
10. Plant functional drawings
11. Abnormal operating instructions
12. Emergency operating instructions

Operational Support Center (OSC)

A description of the OSC is included in the Sequoyah Nuclear Plant Radiological Emergency Plan.

The role of the operational support center is to provide an assembly area for operations support personnel during an emergency situation. The locker and lunchroom space in the powerhouse control bay at elevation 732.0 is designated for use as the operational support center. The operational support center is provided with PAX telephone communications to the main control room.

Emergency Operations Facility (EOF)

A description of the TVA program of a centralized emergency operations concept and an interim nearsite EOF is included in the Sequoyah Nuclear Plant Radiological Emergency Plan.

Based on the licensee's descriptions above and in the Sequoyah Nuclear Plant Radiological Emergency Plan of the technical support center (TSC), the operations support center (OSC), and the interim emergency operations facility (EOF), we conclude that the emergency support facilities are acceptable for the interim. The facilities design concepts will be reviewed for adequacy when they are submitted in June 1981.

III.A.2 Long-Term Emergency Preparedness

Position

Each nuclear facility shall upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement are delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

Discussion

The schedule for implementing the meteorological program for operating nuclear power plants is given in NUREG-0737, Item III.A.2. The three milestones of this section are identified below:

Milestone 1 was met when the licensee submitted an upgraded Radiological Emergency Plan (REP) to NRC on December 31, 1980.

Milestone 2 was met when the licensee provided emergency implementing procedures and descriptions of the methods, systems, and equipment to estimate atmospheric transport and diffusion for use in assessing potential offsite consequences of a radiological condition.

Milestone 3 was met when TVA stated that the REP was implemented to April 1, 1981. TVA letter of April 16, 1981, provided additional information on the implementation of the Radiological Emergency Response Plan. Acceptance criteria of Appendix 2 to NRUEG-0654, however, have not been fully satisfied. Compensating actions of NUREG-0737 will be utilized on an interim basis for satisfying the criteria of Appendix 2 to NUREG-0654.

The Watts Bar data, National Weather Service (NWS) information, and the meterological expertise of the TVA Meteorological Forecast Center (MFC) staff in Mussel Shoals, Alabama are acceptable to meet the requirements for compensating action (i) of NUREG-0737, III.A.2.

The TVA meteorologist at MFC provides an interpretation of the potential transport characteristics in the Emergency Planning Zone. This input combined with the computerized dispersion model available in TVA's Mussel Shoals Emergency Control Center meet the criteria for Class A model.

Remote interrogation of the dose assessments is being addressed by compensating action (iii). The NRC will have direct telephone access to TVA, but the specific design for this telephone system has not been clarified and must be done so prior to full power operations. The license will be conditioned to reflect this.

The compensating actions can only be used until July 1, 1982. By July 1, 1981, a functional description of the upgraded programs and schedule for installation and full operational capability shall be provided to meet milestones 4 and 5. To meet milestone 4 (NUREG-0737, III.A.2), TVA will be

required to install a program by April 1, 1982. To meet milestone 5 (NUREG-0737, III.A.2), TVA will be required to have the program operational by July 1, 1982. The license will also be conditioned to reflect this position.

III.D Worker Protection - Health Physics Program Improvements

In Supplement No. 1 of the Sequoyah Safety Evaluation Report dated February 1980, the NRC staff identified three areas for further actions by TVA for Sequoyah Units 1 and 2: (1) implementation of a radiation protection plan, (2) radiation monitoring improvements, and (3) radiation record collection improvements. NRC staff positions in these areas have been further defined and modified for Sequoyah Units 1 and 2 as follows:

a. Implementation of a radiation protection plan (RPP) for Sequoyah Units 1 and 2 will be required in accordance with the guidance provided for all operating reactors, licensees, and applicants. Draft guidance for RPPs was issued in March 1981 in the form of NUREG-0761, "Radiation Protection Plan for Nuclear Power Reactor Licensees." The requirement for a formal RPP based on a final version of NUREG-0761 is planned for issuance via Technical Specification in October 1981. Implementation of prepared plans is anticipated by April 1982. In a letter dated May 5, 1981, TVA has committed to updating the Sequoyah Units 1 and 2 Radiation Protection Plan upon issuance of final guidance by the NRC. This meets our position in NUREG-0660 and is acceptable.

b. Improvements in radiation monitoring have been implemented by TVA at Sequoyah Units 1 and 2 in accordance with NUREG-0578, -0660, -0694, and -0737. Documentation of the evaluation of these improvements is provided under action plant items II.B.2, II.B.3, II.F.1, and III.D.3.3 of the Sequoyah Units 1 and 2 SER supplements. The actions taken by TVA at Sequoyah are satisfactory and meet our promotions of NUREG-0737.

   Additional guidance for all nuclear reactor licensees and applicants in the area of radiation monitoring improvements is included in the draft version of NUREG-0761, and is planned for issuance with the final version of NUREG-0761.

c. Implementation of improved radiation record collection is also provided as part of draft NUREG-0761. Compliance with this guidance for all nuclear reactor licensees and applicants will be based on the approval and implementation via Technical Specification for another appropriate method and the final version of NUREG-0761. Additionally, health physics appraisals and inspections which cover this area will be periodically conducted to determine compliance.

   Topics addressed in III.D. of Supplement No. 1 of the SER will in the future be addressed under NUREG-0660 and -0737 considered which identify these items, specifically II.B.3, II.F.1, III.D.3.3, and III.D.3.1; item III.D is considered satisfactorily resolved.

III.D.1.1 Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized Water Reactors and Boiling Water Reactors

Position

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

(1) Immediate leak reduction

(a) Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

(b) Measure actual leakage rates with system in operation and report them to the NRC.

(2) Continuing Leak Reduction -- Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

Discussion

In Supplement No. 2 to the SER we stated that TVA had submitted acceptable procedures which are applicable for both units and results of the tests were satisfactory for Unit No. 1. TVA is required to submit the test results of Unit No. 2 prior to exceeding 5 percent power level.

22.3 Dated Requirements

In Supplement No. 2 to the SER we identified five of the 15 dated items that are delayed until January 1, 1982 which was acceptable to the staff. The staff noted in several instances that TVA should be allowed to install some of the instruments during the first forced or scheduled outaged of sufficient length to allow installation after delivery. NUREG-0737 has changed the installation date for II.B.1 (Reactor Coolant System Vents) to July 1982 instead of January 1,1982. We will condition the license for Unit 2 to the July 1982 date, and consider this change for Unit No. 1 if good cause is shown.

24 REACTOR SAFETY STUDY METHODOLOGY APPLICATIONS PROGRAM

In February 1981, Sandia National Laboratories issued the results of a study entitled, "Reactor Safety Study Methodology Applications Program; Sequoyah #1 PWR Power Plant" (NUREG/CR-1659, Volume 1). This report is the first of several reports to be published by Sandia on the results of analysis performed in the Reactor Safety Study Methodology Application Program (RSSMAP). RSSMAP analysis utilizes the methodology developed in the Reactor Safety Study to identify the accident sequences that dominate accident risk for a variety of light-water reactor power plants representative of the current population of plants. Overall, the public risk resulting from a typical pressurized water reactor with an ice condenser containment is expected to be similar to that of a dry containment.

The Sequoyah analysis by Sandia was conducted primarily with information available from the early versions of the Sequoyah Final Safety Analysis Report, Technical Specifications, and selected plant procedures. It is acknowledged that a substantial portion of the Sandia report was written prior to the plant modifications and procedural changes which have been implemented at Sequoyah as a result of the TMI-2 accident. Also, it is acknowledged that the analysis in the report was not upgraded to reflect the new efforts in plant reliability analysis by both the nuclear industry and the Nuclear Regulatory Commission.

Nevertheless, the NRC staff, including the Division of Risk Analysis, RES, has concluded that while more rigorous methodologies may provide more detailed information on the causes of system failures, the most significant conclusions of the Sandia RSSMAP study of Sequoyah Unit 1 are accurately summarized in Section 4.2, "Risk Comparison and Conclusions." The conclusions stated are listed below:

1.0 An important accident sequence occurring for the Sequoyah plant results from the potential for blockage or closure of the drains between the upper and lower compartments. This causes a common mode failure of the ECRS and CSRS when the sump runs dry (sequences S_1HF and S_2HF). The probability of these sequences could be reduced by improved checking procedures and improved fault detection capabilities.

2.0 Failure of the ECRS alone caused by component failures other than the drains also results in some important accident sequences.

3.0 Sequence V, in which check valve failures cause the high-pressure primary coolant to fail the low-pressure piping outside containment, remains an important sequence for Sequoyah. This sequence could be improved by a more strategic testing procedure of the check valves over the limited testing capability which now exists.

4.0 Unlike larger containments, core melting caused by failure of ECIS or ECRS fail the lower pressure, smaller ice condenser containment by overpressure even though the containment cooling system continues to operate properly. The analysis of accident processes by Battelle Columbus Laboratories revealed that the smaller containment pressure and volume design would not withstand the pressure exerted by the noncondensible gases generated in the core meltdown accidents. (This result was similar to the RSS findings for the RSS BWR design.)

5.0 Sequence TMLB'-σ, which was important for the Surry plant as analyzed in the RSS, does not appear to be as significant to risk for Sequoyah due to the lower unavailability of on-site ac power.

6.0 Failure of the containment cooling system causing core meltdown following a small LOCA (the S_2D sequence in the RSS) does not appear to lead to core meltdown at Sequoyah due to the difference in sump water temperature at the time containment failure.

The staff concludes that TVA's responses are satisfactory and the remedial measures taken by TVA for Sequoyah in response to the conclusions of this report is acceptable.

In particular, responses to Sandia conclusions 1 and 3 have resulted in stringent Sequoyah Technical Specifications requirements. Technical Specification for the potential for blockage or closure of the drains between the upper and lower compartments (conclusion 1), are:

Each refueling canal drain shall be demonstrated OPERABLE.

a. Prior to increasing the Reactor Coolant System temperature above 200°F after each partial or complete filling of the canal with water by verifying that the plug is removed from the drain line and that the drain is not obstructed by debris, and

b. At least once per 92 days by verifying, through a visual inspection, that the plug is removed and there is no debris that could obstruct the drain.

For Sequence V (conclusion 3) whereby valve failures causes the high-pressure primary coolant to fail the low-pressure piping outside containment, the Technical Specification limits the leakage to 1.0 gpm from any RCS pressure isolation valve specified in a table. Surveillance requirements fo these valves are that each valve shall be demonstrated operable by verifying leakage to be within itslimit:

a. At least once per 18 months.

b. Prior to entering MODE 2 whenever the plant has been in COLD SHUTDOWN for 72 hours or more and if leakage testing has not been performed in the previous 9 months.

c. Prior to returning the valve to service following maintenance, repair or replacement work on the valve.

d. Within 24 hours following valve actuation due to automatic or manual action or flow through the valve.

No other issues in the Sandia report warrant discussion in the Sequoyah supplementary safety evaluation report. It is noted, however, that TVA has is progress a full scale nuclear safety and availability analysis being performed by Kamon Sciences Corporation. The study should be complete at the end of 1981. TVA agreed to provide a report on this subject matter within 6 months from the date of the KSC report. We will add this agreement as a condition in the Sequoyah Unit No. 2 license.

APPENDIX A

CHRONOLOGY FOR RADIOLOGICAL SAFETY REVIEW

August 1, 1980	Letter to TVA forwarding draft NUREG-0696, "Functional Criteria for Emergency Response Facilities."
August 6, 1980	Letter to TVA requesting additional information concerning hydrogen.
August 7, 1980	Letter to TVA forwarding August 4, 1980 report, "Hydrogen Problems in Sequoyah Containment."
August 12, 1980	Letter from TVA regarding NUREG-0588.
August 13, 1980	Letter from TVA forwarding "Secondary Water Chemistry Program: Sequoyah and Watts Bar Nuclear Plants."
August 14, 1980	Letter from TVA regarding interim distributive ignition system.
August 15, 1980	Letter from TVA forwarding Revision 3 to the Radiological Emergency Plan.
August 15, 1980	Letter from TVA concerning NUREG-0588.
August 19, 1980	Letter from TVA regarding code requirements addressed in the license application.
August 19, 1980	Letter from TVA concerning construction completion dates for Sequoyah, Watts Bar, and Bellefonte.
August 28, 1980	Letter to TVA requesting additional information regarding IDIS.
August 29, 1980	Letter from TVA forwarding Procedure IP-18, "Plant Release Rate Calculations."
September 4, 1980	Letter to TVA forwarding Supplement 2 to the SER (NUREG-0011).
September 4, 1980	Letter from TVA concerning ice condenser insulation materials.
September 4, 1980	Letter from TVA concerning temperature control for main steam valve rooms.
September 4, 1980	Letter from TVA forwarding Annual Financial Report, 1979.

September 5, 1980	Letter to TVA requesting additional information regarding accident evaluation.
September 5, 1980	Letter to TVA forwarding preliminary clarification of TMI Action Plan requirements.
September 5, 1980	Letter from TVA regarding degraded core training for operating employees.
September 5, 1980	Letter from TVA forwarding "Environmental Radioactivity Levels - Sequoyah Nuclear Plant Annual Report, 1979."
September 12, 1980	Letter from TVA concerning containment steel test reports.
September 15, 1980	Letter from TVA concerning containment steel test reports.
September 16, 1980	Letter to TVA forwarding Supplement 3 to the SER (NUREG-0011).
September 17, 1980	Letter from TVA forwarding Revision 6A to the "Physical Security Plan."
September 17, 1980	Letter from TVA regarding replacement schedule for turbocharger drive gear assemblies.
September 17, 1980	Letter from TVA regarding program for resolving ATWS.
September 18, 1980	Letter to TVA forwarding September 8, 1980 ACRS letter regarding ice condenser containments.
September 19, 1980	Letter to TVA concerning preliminary clarification of TMI Action Plan requirements (September 5, 1980 letter).
September 22, 1980	Letter from TVA forwarding Revision 3 of response to NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations."
September 30, 1980	Letter from TVA regarding NUREG-0696, "Functional Criteria for Emergency Response Facilities."
October 1, 1980	Letter to TVA regarding environmental qualification tests on safety-related equipment.
October 3, 1980	Letter from TVA forwarding "Test Report: Verification of Adequacy of Calculations for Sequoyah AC Auxiliary Power System."
October 6, 1980	Letter to TVA concerning Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Supports."

October 16, 1980	Letter from TVA concerning masonry walls issue.
October 20, 1980	Letter from TVA regarding lack of dewatering system for seismic Category I structures.
October 27, 1980	Letter from TVA concerning security personnel training and qualification plans.
October 28, 1980	Letter from TVA regarding technical support center.
October 31, 1980	Letter to TVA forwarding NUREG-0737, "Clarification of TMI Action Plan Requirements."
November 4, 1980	Letter to TVA requesting additional information regarding degraded core program.
November 4, 1980	Letter to TVA regarding tiles used in control room ceiling.
November 5, 1980	Letter to TVA requesting additional information regarding reactor coolant system vents.
November 10, 1980	Letter from TVA concerning operator training and qualification programs.
November 10, 1980	Letter from TVA regarding fuel load date for Unit 2.
November 13, 1980	Letter to TVA concerning revised radiological emergency response plans.
November 13, 1980	Letter from TVA forwarding outline to shift technical advisor training and requalification program.
November 14, 1980	Letter to TVA regarding deletion of high pressure blowdown tests.
November 17, 1980	Letter to TVA regarding peak pressure containment integrated leak rate test and full pressure preoperational containment integrated leak test.
November 17, 1980	Letter from TVA regarding IE Bulletin 80-09, "Hydramotor Actuator Deficiencies."
November 24, 1980	Letter from TVA forwarding application for amendment to License DPR-77 to authorize storage of low-level radwaste.
November 26, 1980	Letter to TVA regarding implementation of guidance for Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Supports."
November 26, 1980	Letter to TVA regarding environmental qualification of safety-related electrical equipment.

December 1, 1980	Letter from TVA clarifying TVA's control of construction and preliminary testing.
December 3, 1980	Letter to TVA forwarding Appendix R to 10 CFR 50.48 regarding fire protection program requirements.
December 5, 1980	Letter from TVA regarding the natural circulation tests performed on Unit 1.
December 9, 1980	Letter to TVA forwarding Revision 1 to NUREG-0654/ FEMA-REP-1.
December 9, 1980	Letter from TVA regarding environmental qualification testing of safety-related equipment.
December 9, 1980	Letter from TVA forwarding planned changes to Chapter 17 of the FSAR for Sequoyah, Watts Bar, and Bellefonte.
December 10, 1980	Letter from TVA forwarding response to Revision 3 of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations."
December 15, 1980	Letter from TVA regarding item III.D.1.1 of the TMI-2 Action Plan.
December 15, 1980	Letter from TVA regarding modifications to containment isolation valves.
December 16, 1980	Letter from TVA regarding Unit 1 special natural circulation test program.
December 17, 1980	Letter from TVA regarding status of emergency plan items.
December 22, 1980	Letter to TVA regarding control of heavy loads.
December 29, 1980	Letter to TVA regarding the resolution of the ATWS issue.
December 31, 1980	Letter from TVA regarding ERCW settlement monitoring.
December 31, 1980	Letter from TVA regarding design details of postaccident sampling system.
December 31, 1980	Letter from TVA regarding barge collision issue.
December 31, 1980	Letter from TVA forwarding revised Radiological Emergency Plan.
January 2, 1981	Letter from TVA forwarding "Westinghouse Reactor Vessel Level Instrumentation System for Monitoring Inadequate Core Cooling (Upper Head Injection)."

January 7, 1981	Letter from TVA regarding NUREG-0737, Items I.C.6, II.E.4.2, II.K.3.1, and II.K.3.2.
January 13, 1981	Letter from TVA regarding control room habitability.
January 14, 1981	Letter to TVA regarding hydrogen control system.
January 14, 1981	Letter from TVA regarding potential flammability of ceiling tiles in control room.
January 15, 1981	Letter to TVA requesting additional information regarding guard training and qualification plan.
January 15, 1981	Letter from TVA forwarding "Environmental Radioactivity Levels, Sequoyah Nuclear Plant, Annual Report 1979."
January 15, 1981	Letter from TVA regarding modifications to containment boundary components.
January 16, 1981	Letter from TVA regarding fuel load date for Unit 2.
February 2, 1981	Letter from TVA regarding nonreinforced concrete masonry block walls.
February 3, 1981	Letter to TVA forwarding pages omitted from December 22, 1981 letter regarding control of heavy loads.
February 4, 1981	Letter from TVA forwarding revised physical security plan.
February 5, 1981	Letter from TVA regarding environmental qualification of electrical equipment.
February 6, 1981	Letter from TVA forwarding revised physical security plan.
February 12, 1981	Letter from TVA regarding design criteria for effluent monitoring, sampling, and analysis equipment.
February 12, 1981	Letter from TVA regarding reevaluation of construction completion schedule.
February 17, 1981	Letter from TVA regarding centralized emergency operations program.
February 18, 1981	Letter to TVA forwarding Supplement 4 to the SER (NUREG-0011).
February 20, 1981	Letter to TVA regarding NUREG-0619.
February 20, 1981	Letter from TVA regarding status of turbine disk inspection, special natural circulation program, verification of adequacy of transformer tap settings, and proposed change to Unit 1 Technical Specification 3.6.1.9.

February 23, 1981	Letter from TVA regarding NUREG-0737, Item II.E.4.2.
February 25, 1981	Letter to TVA regarding capacity to mitigate station blackout event and promptly implement emergency procedures.
February 26, 1981	Letter to TVA regarding the periodic updating of FSARs.
February 26, 1981	Letter from TVA regarding guard training and qualification plans.
February 27, 1981	Letter to TVA regarding November 24, 1981 application to amend license to authorize onsite low-level waste storage.
March 3, 1981	Letter from TVA regarding implementing procedures for the Radiological Emergency Plan.
March 3, 1981	Letter from TVA regarding auxiliary feedwater pump endurance test.
March 5, 1981	Letter to TVA forwarding NUREG-0696, "Functional Criteria for Emergency Response Facilities."
March 9, 1981	Letter from TVA regarding interim operation of facility during initial criticality until fire protection modifications for ERCW system are complete.
March 10, 1981	Letter to TVA regarding environmental qualification of safety-related electrical equipment
March 10, 1981	Letter from TVA regarding installation of igniters in Unit 2 at locations similar for Unit 1.
March 10, 1981	Letter from TVA regarding compliance with NUREG-0737, Item II.F.1.
March 12, 1981	Letter from TVA regarding NUREG-0737, Item II.K.3.17.
March 13, 1981	Letter from TVA informing that fuel load date for Unit 2 is May 1, 1981.
March 16, 1981	Letter from TVA forwarding "Research Program on Hydrogen Combustion and Control, Quarterly Progress Report 2."
March 20, 1981	Letter from TVA forwarding "Assessment of Ultrasonic Reflectors in Sequoyah Unit 2 Reactor Vessel Nozzle Bores."
March 20, 1981	Letter from TVA forwarding revisions to Emergency Implementing Procedures I-18.
March 24, 1981	Letter from TVA regarding NUREG-0578, Item 2.1.6a.

March 27, 1981	Letter from TVA regarding guard training, qualification plan, and safeguards contingency plans.
March 31, 1981	Letter from TVA forwarding revised Radiological Emergency Plan (central files version).
March 31, 1981	Letter from TVA requesting extension of construction completion date.
April 2, 1981	Letter from TVA regarding critical systems, structures, and components list.
April 2, 1981	Letter from TVA regarding NUREG-0737, Item I.C.6.
April 2, 1981	Letter from TVA regarding evacuation time estimates per NUREG-0654.
April 2, 1981	Letter from TVA regarding report on operating experience of Unit 1 purge/vent valves before startup after first refueling.
April 2, 1981	Letter from TVA regarding AC auxiliary power system testing for Unit 2.
April 2, 1981	Letter from TVA notifying NRC that no modifications are required as a result of 10 CFR Part 50, Appendix R.
April 3, 1981	Letter from TVA regarding licensing schedule for Sequoyah and Watts Bar.
April 3, 1981	Letter from TVA regarding process control program.
April 3, 1981	Letter from TVA regarding NUREG-0737, Item II.K.3.2.
April 3, 1981	Letter from TVA regarding applicability of December 19, 1981 submittal concerning NUREG-0737 to Unit 2.
April 6, 1981	Letter from TVA regarding vulnerability of ERCW intake structure to barge collision.
April 7, 1981	Letter from TVA forwarding revision to Emergency Plan Implementing Procedure I-18 (central files version).
April 7, 1981	Letter from TVA forwarding revisions to security personnel training, qualification plans, and safeguards contingency plans.
April 7, 1981	Letter from TVA regarding settlement monitoring program of the ERCW.
April 8, 1981	Letter from TVA regarding results of auxiliary building gas treatment system test.

April 13, 1981	Letter from TVA regarding startup program.
April 13, 1981	Letter from TVA regarding compliance with NUREG-0737, Item II.F.2.
April 15, 1981	Letter from TVA forwarding page correction to April 13, 1981 letter regarding startup program.
April 16, 1981	Letter from TVA regarding current status of SER open items and NUREG-0737, Items III.A.1.2 and III.A.2.
April 17, 1981	Letter from TVA regarding hydrogen control.
April 17, 1981	Letter from TVA regarding preoperational test program modifying reactor coolant system flow measurement test.
April 20, 1981	Letter from TVA regarding centrifugal charging pump miniflow isolation.
April 21, 1981	Letter from TVA informing NRC of continued support and participation in hydrology committee of Water Resources Council.

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16. ABSTRACT (200 words or less)

Supplement No. 5 to the Safety Evaluation Report of Tennessee Valley Authority's application for licenses to operate its Sequoyah Nuclear Plant, Units 1 and 2, located in Hamilton County, Tennessee, has been prepared by the Office of Nuclear Reactor Regulation of the U. S. Nuclear Regulatory Commission. The purpose of this supplement is to update our evaluations on issues identified in the previous SER and supplements that need resolution prior to licensing Unit 2.

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