SAFETY EVALUATION

BY THE

DIRECTORATE OF LICENSING

U. S. ATOMIC ENERGY COMMISSION

IN THE MATTER OF

DUKE POWER COMPANY

OCONEE NUCLEAR STATION UNITS 2 AND 3

DOCKET NOS. 50-270/287

July 6, 1973

PREFACE

Prior to issuing Safety Evaluation by the Division of Reactor Licensing, U. S. Atomic Energy Commission, In the Matter of Duke Power Company Oconee Nuclear Station, Docket No. 50-269 on December 29, 1970, the Division of Reactor Licensing (now the Directorate of Licensing) performed a safety evaluation which considered all three Oconee reactors (Units 1, 2 and 3). Because the status of facility construction warranted only consideration of Oconee Unit 1 for an operating license at that time, the December 29, 1970 Safety Evaluation Report addressed only Unit 1. Although considerable supplemental review and evaluation was performed by the Directorate of Licensing on Units 2 and 3, much of the original review remained applicable to these two units. For this reason this Safety Evaluation Report for Units 2 and 3 was prepared in the same format as the December 29, 1970 document to facilitate referencing areas of review, evaluation and conclusions mutually applicable to all three reactor units.

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1.0 INTRODUCTION

The Duke Power Company (applicant), by application dated November 28, 1966, and as subsequently amended, requested a license to construct and operate three pressurized water reactors, identified as Units 1, 2, and 3 at its Oconee Nuclear Station in Oconee County, South Carolina. The Atomic Energy Commission (AEC) reported the results of its review prior to construction in a Safety Evaluation Report (SER) dated August 4, 1967. Following a public hearing before an Atomic Safety and Licensing Board in Walhalla, South Carolina, on August 29-30, 1967 and September 12, 1967, the Director of Reactor Licensing issued Provisional Construction Permits CPPR-33, 34, and 35 for Units 1, 2, and 3, respectively, on November 6, 1967.

On June 2, 1969, the applicant filed, as Amendment 7, the Final Safety Analysis Report (FSAR) required by Section 50.34(b) of Chapter 10 of the Code of Federal Regulations as a prerequisite to obtaining an operating license for each unit.

The AEC regulatory staff (staff) review of the FSAR, as amended, considered all three units of the Oconee Nuclear Station. However, Unit 1 was the only unit whose state of completion warranted issuance of an operating license at that time and the SER for Unit 1 was published December 29, 1970.

In the course of this early review of the material submitted, the staff held a number of meetings with representatives of the applicant;

the nuclear steam supplier, the Babcock & Wilcox Company (B&W); and the designer of the reactor containment building, the Bechtel Corporation; to discuss the plant design and construction and the proposed operation. A chronology of the staff review which resulted in the licensing of Oconee Unit 1 for operation is presented in Appendix A of the Oconee Unit 1 SER.

In addition, the AEC Advisory Committee on Reactor Safeguards (ACRS) considered this project and met with both the applicant and the staff to discuss it. The report of the ACRS, dated September 23, 1970, is included as Appendix B to the Oconee Unit 1 SER.

Also included as Appendices to the Oconee Unit 1 SER are reports by the staff consultants on meteorology, hydrology, ecological (Fish and Wildlife) considerations and seismic design and a staff financial analysis.

Since the original regulatory staff review of Oconee Unit 1, a supplemental review of the plant emergency core cooling systems was performed in accordance with the criteria described in an Interim Policy Statement issued on June 25, 1971, and published in the FEDERAL REGISTER on June 29, 1971 (36 F.R. 12247). The safety evaluation based upon this review was issued March 24, 1972, as Supplement No. 1 to the Oconee Unit 1 SER. The safety evaluation and conclusions presented in Supplement No. 1 are applicable to Oconee 2 and 3.

In March 1972, the Oconee Unit 1 suffered damage to the steam generators and reactor vessel internals requiring significant design modifications. The staff evaluation of these design modifications was published in Supplement No. 2 to the Oconee Unit 1 SER on December 19, 1972. Since the Oconee Units 2 and 3 vessel internals and the reactor systems in general are identical to Unit 1, the evaluation presented in Supplement No. 2 is applicable to Units 2 and 3.

The application for operating licenses for Units 2 and 3 requested a licensed core thermal power level of 2568 megawatts. The staff evaluation of the engineered safety features and accident analyses were performed for this power level. Further, the analyses included the 16 megawatts of reactor coolant pump heat in the reactor coolant system in addition to the 2568 megawatts from the reactor core. The proposed licenses authorize operation at core power levels up to and including 2568 megawatts.

The staff safety review with respect to issuing operating licenses for Units 2 and 3 was based on the applicant's FSAR (Amendment 7) and subsequent Amendments 8 through 41 inclusive (Amendments 1 through 6 were related to the construction permit review), all of which are available for review at the Atomic Energy Commission's Public Document Room at 1717 H Street, N.W., Washington, D. C. A chronology of the staff review subsequent to issuance of the SER for Oconee Unit 1 is contained in Appendix A of this report.

The staff concluded that Units 2 and 3 of the Oconee Nuclear Station can be operated without undue risk to the health and safety of the public. Subsequent to issuance of operating licenses, the units will be required to operate in accordance with the terms of the license and the AEC regulations under the surveillance of the AEC regulatory staff.

2.0 FACILITY DESCRIPTION

Units 2 and 3 are two of three reactor units to be operated at the Oconee Nuclear Station. In all essential respects, Units 2 and 3 are identical to Unit 1, the first nuclear power plant using a B&W nuclear steam supply system licensed for operation of this generation of B&W reactors. All three units share some auxiliary systems although the degree of independence for Unit 3 is greater than for Unit 2, primarily because Unit 1 and Unit 2 share a control room, certain radwaste processing systems, and a fuel handling facility. However, the engineered safety feature components, except for portions of the hydrogen purge systems, are not shared among the units. Further general description of the plant is presented on pages 3, 4, and 5 of the Oconee Unit 1 SER.

3.0 SITE AND ENVIRONMENT

The staff review and evaluation of the Oconee Station site and environment are contained on pages 5-10 of the Oconee Unit 1 SER. Since that review and evaluation, the applicant, at staff request, provided additional information on site meteorology, hydrology and other factors related to site location which changed since the original review.

Also since the original review and evaluation, a complete environmental study was performed in accordance with the National Environmental Policy Act, and a notice of the availability of the AEC Environmental Statement was published in the FEDERAL REGISTER on April 1, 1972.

3.1 Site Location and Description

Since the staff review and evaluation presented in the Oconee Unit 1 SER, the applicant was requested to update information on the population about the site and on nearby industries, transportation, and military facilities.

Access to the Oconee site is provided by public highways which pass through the 1 mile exclusion radius, the closest being more than 1000 feet from the reactor. There are no oil or gas pipelines or industrial activities within 5 miles of the site. The nearest rail line is approximately 6 miles south of the plant site. The staff concluded that site location with respect to adjacent transportation activities is acceptable.

3.2 Meteorology

3.2.1 Regional Meteorology

Western South Carolina is far south of major storm tracks but experiences higher precipitation amounts than the east coast due to its location in the lee of the Appalachian Mountains. A semi-permanent belt of high pressure usually influences the regional climate. During the fall season, the area has a high probability of experiencing atmospheric stagnation during which the dilution rate for effluents is low due to low wind speeds.

3.2.2 Local Meteorology

The Oconee plant site is situated on Lake Keowee which was established to provide cooling for the three power units. The topography in the vicinity of the site is hilly and the local airflow is influenced to some extent by the contour of the lake. The prevailing winds are divided between the southwest and northeast quadrants due to the lake orientation and large scale pressure effects.

3.2.3 Onsite Meteorological Measurements Program

A preliminary meteorological survey of the site from October 1966 to October 1967 was based on a wind measuring system located on a 14-meter pole and a temperature measuring system that used thermographs in standard

Weather Bureau Shelters stationed on the site at varying terrain elevations. Beginning in November 1967, a 46-meter tower on a knoll 850 feet WNW of the reactor complex was instrumented with a sensitive wind measuring system at the 46-meter level and an aspirated, shielded temperature measuring system with temperature units located at the 2-, 10-, 28- and 46-meter levels. The applicant initially submitted a one year period of data record (June 19, 1968 - June 18, 1969) in joint frequency distribution form using vertical temperature difference (ΔT) between the 46- and 2-meter levels to stratify the data into stability categories. However, there were wind calibration problems associated with these data. Due to the delay in the construction of Units 2 and 3, a two year period of record (March 15, 1970 - March 14, 1972) of onsite tower data for the same levels after the filling of Lake Keowee was submitted for evaluation at the request of the staff. These data were free of calibration problems and the ΔT class intervals were presented as suggested in Regulatory Guide 1.23, Onsite Meteorological Programs. The data recovery for this period of record was 82%.

3.2.4 Short Term (Accident) Diffusion Estimates

In evaluating diffusion of short-term accidental releases from the plant, a ground level release with a building wake factor, cA, of 1270 square meters was assumed. The wind speeds at the 150-foot level of the tower were multiplied by 0.8 to achieve a representation of the winds appropriate to a ground level release. The relative concentration

(χ/Q) which is exceeded 5% of the time was calculated to be 2.2×10^{-4} seconds per cubic meter at the exclusion radius of 1609 meters. This relative concentration was equivalent to dispersion conditions produced by Pasquill type F stability with a wind speed of 1 meter per second.

The applicant presented wind direction and speed persistence information for long periods of record from Greenville and Donaldson Air Force Base, South Carolina from which estimates were made of relative concentrations for time periods up to 30 days. These estimates are in essential agreement with those presented in Regulatory Guide 1.4, Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors. Therefore, the staff concluded that the relative concentrations presented in Regulatory Guide 1.4 provide adequately conservative estimates for the outer boundary of the low population zone (9654 meters).

3.2.5 Long Term (Routine) Diffusion Estimates

The maximum annual average relative concentration of 3.6×10^{-6} seconds per cubic meter was found at the exclusion radius (1609 meters) south of the plants. This value is lower than the applicant's value by about 25% due primarily to the applicant's use of the 1968-1969 data.

3.2.6 Conclusion

The staff concluded that the two years of data after the filling of Lake Keowee provided an acceptable basis for evaluating atmospheric diffusion for accidental and routine gaseous effluent releases from the plants.

3.3 Hydrology

3.3.1 Hydrologic Description

Lake Keowee, which has a gross storage capacity of 956,000 acre-feet at normal full pool, was formed by Keowee Dam, on the Keowee River, and Little River Dam, on the Little River. The two arms of the lake are connected by a channel which normally allows them to act as one body of water. The dams are earthfill structures, 150 and 170 feet high, respectively. Upstream, on the Keowee River arm of the lake, and in the backwater of Lake Keowee, is the applicant's Jocassee Dam and reservoir, a pump-back hydropower facility. Jocassee Lake was formed by a 385-foot rockfill dam and has a gross storage capacity of about 1,160,000 acre-feet at normal full-pool. Jocassee Dam controls about 148 square miles of the total 439 square mile basin above the Keowee-Little River Dams.

Downstream from Lake Keowee is Hartwell Reservoir, a Corps of Engineers reservoir, with a total capacity of about 2,842,700 acre-feet.

The applicant reported that facilities have been constructed on Lake Keowee to provide the Town of Seneca with raw water. The intake is about 6 miles from the Oconee Station. Hartwell Reservoir downstream provides raw water supplies for several industrial plants, Clemson University, and the Towns of Clemson, Pendleton, and Anderson, South Carolina. Data provided by the applicant indicated that the total average withdrawal from Hartwell Reservoir by these users is about 4.85 million gallons per day.

3.3.2 Floods

The plant site is located on the watershed boundary of the Keowee and Little River Valleys and is more than 100 feet above the natural valley floor. Therefore, historical flood levels have little meaning to site safety considerations. The peak river flow of record at the Keowee River gage near Jocassee, South Carolina, was 21,000 cubic feet per second (cfs) on October 4, 1964. The annual average flow and minimum recorded flow (October 7, 1954) were 468 cfs and 57 cfs, respectively.

The applicant estimated the probable maximum flood (PMF) would produce a maximum static water surface of about 808 feet above mean sea level (MSL). In addition, wind generated waves produced by a postulated wind speed of 45 miles per hour were estimated by the applicant to produce runup to elevation 813.3 feet MSL. Since the applicant's dams and protective dike near the intake are constructed to elevation 815 feet MSL, the applicant concluded there are no flood problems at the site.

An independent analysis by the staff and its consultant (see Appendix D) using estimates of probable maximum precipitation, based on Weather Bureau (now NOAA) Hydro-Meteorological Report No. 33, and standard reservoir routing techniques, resulted in somewhat higher maximum water surface elevation and wave runup attained during a PMF. For this analysis the maximum water surface elevation was 809.8 feet MSL and the runup of wind waves, generated by a 45 mile per hour (mph) wind speed assumed coincident with the PMF, reach elevations between 813.8 and 814.8 feet MSL (near the top of the dam). The staff concluded that the riprap armored surface of the structure can adequately withstand the runup and even an occasional overwash if that should occur.

The conditions mentioned above are also applicable to the intake canal, intake basin dike (top elevation 815 feet MSL), and circulating water pumps except that the effective fetch is less and constrained to a narrower sector than for the Keowee Dam. The applicant identified four sources of water for shutdown and cooldown of the plant; (1) water from Lake Keowee via the intake canal using the circulating water pumps; (2) gravity flow through the circulating water system; (3) water trapped between the submerged weir in the intake canal and the intake structure in the event of a loss of Lake Keowee and; (4) 8,825,000 gallons of water trapped in the plant circulating water system with appropriate valving, pumping and recirculation as a backup in the event of the loss of all external water supplies. Only two (1 and 3) of the four water supply systems require the availability of the circulating water pumps.

3.3.3 Surge Flooding

The relative size of the reservoirs around the plant, and the distance of the site from the coast, are considered the major impediments to hurricane induced surge flooding of a severity approaching that which is caused by runoff type flooding. During review of similarly located sites, the staff found that the surge producing winds would be significantly reduced when land mass frictional effects are encountered.

3.3.4 Cooling Water

Water for the once-through condenser cooling is withdrawn from the Little River arm of Lake Keowee at the rate of about 4,700 cfs. The heated water is discharged into the Keowee River arm just upstream of Keowee Dam.

As a result of discussions with the staff and the ACRS the applicant added a submerged weir in the intake canal as described in Supplements 4, 5, and 6 to this application dated May 25, 1967, June 16, 1967 and March 26, 1969, respectively. As described in Supplement 4, the purpose of this weir is to provide an emergency pond of cooling water (67×10^6 gallons) should the water supply from Lake Keowee be lost for any reason. Additional details on the design of this weir were provided in Supplement 5. Following issuance of construction permits or the design of this submerged weir. Following a review of this additional data by the staff consultant, Newmark and Hall, the staff concluded, in a letter to the applicant dated May 2, 1969 that the weir was acceptable.

Subsequently, during the OL review of Units 2 and 3, the staff elected to examine this matter further. The staff requested the applicant to reanalyze the capability of the weir to withstand internal and external hydraulic forces in more detail and using more conservative assumptions that had been used in the original design. Based on results obtained using these more conservative assumptions, the staff concluded that a rapid drawdown of Lake Keowee could cause considerable displacement of the riprap used to face the weir. However, the staff has not required the applicant to redesign the weir in as much as even if the staff were to postulate complete failure of the weir, the 8.8 million gallons of water trapped in the condenser intake and discharge lines would provide 37 days worth of emergency cooling. Therefore the staff concluded that there is adequate emergency cooling water supply under all reasonable postulated failures.

3.3.5 Environmental Acceptance of Effluents

The staff and its consultant, the U.S. Geological Survey (U.S.G.S.), concluded during the PSAR review that operational and emergency release of plant effluent can be adequately diluted by hydropower plant releases from Keowee Dam. The U.S.G.S. noted, in the earlier review, that under certain conditions some radionuclides could be concentrated in the sediment of Hartwell Reservoir. The applicant stated that his monitoring program was recently expanded to include sediment sampling.

3.3.6 Ground Water

Throughout the plant area, ground water occurs at shallow depths within the saprolite soil mantle. This saprolite soil, which is about 40 feet thick at the site, is the aquifer for the ground water supply of the area. The hydraulic gradient of the unconfined water in the relatively impermeable saprolite which mantles the area tends to follow the surface topography directing flow southeast toward the Keowee River downstream of Keowee Dam. The flow pattern should not be materially altered by the water level in Lake Keowee. Therefore, the staff and its consultant, the U.S. Geological Survey, concluded that ground water supplies in the area should not be adversely affected by the accidental release of radionuclides at the site.

3.3.7 Conclusions

The staff concluded that the applicant's facilities are acceptable with respect to flooding and water supply availability.

In addition, the staff and its consultant (the U.S.G.S.) concluded that any liquid plant releases will be adequately dispersed downstream.

3.5 Environmental Radiation Monitoring

The staff's recent evaluation of the Oconee Station radiological environmental monitoring program was essentially the same as that presented in the Oconee Unit 1 SER (page 10). However, the program was modified recently (FSAR Revision 23) to reflect the most recent AEC policies pertaining to environmental monitoring. Program changes included weekly sampling of milk instead of quarterly, elimination of gross beta count screening of samples, and the addition of air particulate sampling and analysis for I-131. The results of an annual survey of milk producing cows within five miles of the site was added to the reporting requirements for the program. The staff concluded that the modified environmental radiation monitoring program is acceptable.

4.0 REACTOR DESIGN

4.1 General

Since the staff review and evaluation described on pages 11-19 of the Oconee Unit 1 SER, the applicant made some minor changes in the reactor design affecting all three Oconee units. The applicant decided not to use unpressurized fuel in Oconee Unit 1 and not to share fuel between Unit 1 and Unit 3. Also, during fabrication inspection, defects were discovered in some of the control rod drive motor extension tubes which form part of the primary system pressure boundary. In a separate incident in Oconee Unit 1, a number of control rod drives were damaged during preoperational testing due to a "dry trip" (insufficient water in the hydraulic snubber regions). The staff evaluated these situations as discussed below. The staff also supplemented its earlier review in the areas of nuclear design and loss-of-coolant and seismic excitation of the core and its internals.

4.2 Nuclear and Thermal-Hydraulic Design

4.2.1 Nuclear Analysis

The staff review of the nuclear design of the B&W Oconee reactors was based on the information provided by the applicant in the FSAR and revisions thereto, discussions with the applicant and B&W, and the results of independent calculations performed for the staff by the Brookhaven National Laboratory. Basic plant design data are shown in Table 4-1.

TABLE 4-1

Design Data	Oconee I	Oconee II	Oconee III
Design Heat Output, MWt	2568	2568	2568
Vessel Coolant Inlet Temp, F	554	554	554
Vessel Coolant Outlet Temp, F	603.8	603.8	603.8
Core Outlet Coolant Temp, F	606.2	606.2	606.2
Core Operating Press., PSIG	2185	2185	2185
Total No. Fuel Assemblies	177	177	177
Fuel Rods Per Assembly	208	208	208
Control Rod Guide Tubes/Assembly	16	16	16
In-Core Inst. Positions/Assembly	1	1	1
Active Fuel Length In.	144	144	144
Fuel Den., % Theoretical	93.5	92.5	92.5
Avg. Power Density Kw/l	83.38	83.38	83.38
Avg. Thermal Output, kW/ft.	5.656	5.656	5.656
Total Reactor Coolant Flow, lb/hr.	131.32×10^6	131.32×10^6	131.32×10^6
Max./Avg. Power, Radial x Local	1.78	1.78	1.78
Max./Avg. Power, Axial	1.70	1.70	1.70
Overall Power Ratio (F_Q. Nuclear)	3.03	3.03	3.03
Power Peaking Factor (F_Q)	1.011	1.011	1.011
Local Heat Flux Factor (F_Q)"	1.014	1.014	1.014
Design Overpower (%)	114	114	114
DNB Ratio at Design Overpower (W-3)	1.55	1.55	1.55
DNB Ratio at Design Power (W-3)	2.0	2.0	2.0
Limiting DNB Ratio at Design Overpower (W-3)	1.3	1.3	1.3
Metric Tons UO_2 (BOL CY1)	94.1	93.1	93.1
Metric Tons Uranium	83.0	82.1	82.1
Full Power Days Cycle 1	310	310	456
Full Power Days Following Cycles	310	310	310
Avg. MWD/MTU (Cycle 1)	9600	14,400	14,275
Avg. MWD/MTU (Following Cycles)	9700	9700	9700
Avg. Loaded Enrichment (Cy. 1) wt. %	2.10	2.62	2.56
No. Full Length CRA's	61	61	61
No. of APSR's	8.0	8.0	8.0
Total Rod Worth (61 rods), BOL $\%\Delta\rho$	12.1	11.1	11.1

TABLE 4-1 (Cont'd)

Design Data	Oconee I	Oconee II	Oconee III
Stuck Rod Worth (BOL), %Δρ	-2.1	-3.4	-3.4
Max. Ejected Rod Worth, %Δρ	.5	.5	.5
Net Available Minus Required Rod Worth (BOL) %Δρ	+5.4	+3.7	+3.7
Boron Worth (HOT) (%Δk/k) ppm BOL	1/85	1/100	1/100
Boron Worth (COLD) (%Δk/k) ppm BOL	1/64	1/75	1/75
Moderator Temp. Coeff. BOL CY1, 10^{-4} Δk/k/°F	+0.27	+0.03	-0.01
Max. Mod. Temp. Coeff. 10^{-4} Δk/k/°F	.9	.9	.9
Mod. Temp. Coeff. CY1 EOL 10^{-4} Wk/k/°F	-2.8	-2.6	-2.6
Power Coeff. 10^{-4} Δρ/% Pwr. BOL	-1.11	-1.1	-1.1
Burnup & Fission Products Controlled By (BPRA) %Δρ	0.0	4.0	4.0
Max. Reactivity Insertion Withdrawing Single Reg. CRA Group (Δk/k)/s	1.1×10^{-4}	1.1×10^{-4}	1.1×10^{-4}
Max. Reactivity Insertion with Soluble Boron Removal (Δk/k)/s	4.4×10^{-6}	4.4×10^{-6}	4.4×10^{-6}

The applicant described the computer programs and calculational techniques used by B&W to predict the nuclear characteristics of the reactor designs, and provided examples to demonstrate the ability of these methods to predict the results of critical experiments using UO_2 and PuO_2-UO_2 fuel.

The applicant also performed analyses, using a two-dimensional PDQ* computer program in conjunction with fuel cycle calculations performed with the use of the HARMONY** computer program, to provide estimates of core fuel burnups and first and second cycle and equilibrium core enrichments.

The staff concluded that the information presented adequately demonstrates the ability of these analyses to predict reactivity and the physics characteristics of the reactors.

4.2.2 Power Distribution

Detailed three-dimensional power distribution measurements were performed at the B&W Critical Experiments Laboratory. The results of the applicant's calculations using PDQ07,* a three-dimensional computer program, agreed quite well with the measured power distribution. PDQ07, as used by B&W, incorporates a thermal feedback in obtaining radial and axial power distributions for operations involving (1) changes in control rod positions, (2) various xenon stability and control conditions, and (3) various reactivity coefficients.

*W. R. Cadwell, PDQ07 Reference Manual, WAPD-JM-678, Bettis Atomic Power Laboratory, Pittsburgh, PA., January 1967.

**R. J. Breen, O. J. Marlowe, and C. J. Pfeifer, HARMONY: System for Nuclear Reactor Depletion Computation, WAPD-TM-478, Westinghouse, January 1965.

The axial distribution of power was calculated for two conditions of reactor operation. The first condition was an inlet peak resulting from partial insertion of a Control Rod Assembly (CRA) group. This condition resulted in the maximum local heat flux and maximum linear heat rate. The second power shape was a symmetrical cosine which was indicative of the power distribution with xenon override rods withdrawn. Both of these flux shapes were evaluated for thermal departure from nucleate boiling (DNB) limitations set by the applicant. The limiting condition was found to be the cosine power distribution ($P/\overline{P} = 1.5$) although the inlet peak shape had the larger maximum value ($P/\overline{P} = 1.7$). However, the position of the cosine peak farther up the channel resulted in a less favorable flux to enthalpy relationship and, therefore, the cosine axial shape was used by the applicant to determine individual channel DNB limits.

The staff concluded that the analytical methods used to calculate power distribution were adequate and that core thermal limits were conservatively based on the most restrictive power peaking factors.

4.2.3 Moderator Temperature Coefficient

The moderator temperature coefficient is positive at the beginning of the initial fuel cycle due to the use of soluble boron for reactivity control. The applicant's calculations showed that above 525°F, the consequences of postulated reactivity accidents are acceptable. Since the moderator temperature coefficient at lower temperatures is less negative (or more positive) than at operating temperatures, the startup and operation of the reactor when the reactor coolant temperature is less than 525°F is prohibited except where necessary for low power physics tests, for which case special operating precautions are taken.

The maximum moderator temperature coefficient at full power is not permitted to exceed $+0.9 \times 10^{-4}$ $\Delta k/k°F$ for Oconee Units 2 and 3 by the Technical Specifications. The nominal beginning of life (BOL) cycle 1 value is substantially less positive than this and, in fact, is negative for Oconee 3. The accident analyses including the calculation of clad temperature for the LOCA used the conservative maximum positive Technical Specifications value.

The staff concluded that the applicant conservatively accounted for the influence of a positive moderator temperature coefficient on various postulated accidents and adequately demonstrated its acceptability.

4.2.4 Control Requirements

To allow for changes of reactivity due to reactor heatup, operating conditions, fuel burnup and fission product buildup, a significant amount of excess reactivity was built into the core. The applicant provided substantial information relating to core reactivity balances for first and equilibrium cycles for BOL and end of life (EOL) and showed that means were incorporated into the design to control excess reactivity at all times. This was done through the use of soluble boron in the reactor coolant and moveable control rods. Fuel burnup and fission product buildup are also controlled by fixed B_4C burnable poison rod assemblies (BPRA) in Oconee Units 2 and 3. The BPRA are used rather than increased soluble poison to prevent the BOL moderator temperature coefficient from becoming more positive. The applicant conservatively showed by analysis that the core can be maintained in a subcritical condition by at least 1% $\Delta k/k$ with operating boron concentrations even with the highest worth control rod assembly withdrawn. In addition, under conditions where a cooldown to reactor building ambient temperature is required, concentrated soluble boron can be added to the reactor coolant to produce a shutdown margin of at least 1% $\Delta k/k$ even with all the control rod assemblies withdrawn from the core.

On the basis of the review, the staff concluded that the applicant's assessment of reactivity control requirements over the core lifetime was suitably conservative, and that adequate negative worth is provided by the control rods, the soluble boron system, and the burnable poison rod assemblies to assure shutdown capability.

4.2.5 Stability

The basic instrumentation for monitoring the nuclear power level and distribution in the B&W reactors is the same in principle as for all PWR plants recently licensed for operation. Primary reliance is placed on four axially split, out-of-core detectors that are spaced approximately 90° apart around the reactor pressure vessel. Also, 52 assemblies of self-powered in-core neutron detectors are available for in-core mapping. Each assembly can measure local neutron flux at seven elevations in the core. Normally, the output of these detectors is read out through the plant computer; however, a backup readout system is provided for selected detectors (this capability is required by the Technical Specifications). The applicant provided for availability of these detectors for monthly calibration of the out-of-core detector tilt factor. Test results showing that these in-core detectors have a rated lifetime in excess of 5 years and a precision of ±5% in determining relative power distribution were presented in B&W Topical Report BAW-10001, Incore Instrumentation Test Program, August 1969 which the staff found acceptable.

The staff concluded that the out-of-core detectors are adequate for detecting power maldistributions originating from axial xenon instability and misplaced control rods if a power distribution mapping capability is provided by the in-core detectors to calibrate the out-of-core detectors periodically and to investigate any power distribution anomalies detected by the out-of-core detectors.

The staff reviewed the applicant's analyses of xenon-induced oscillations which are reported in three B&W Topical Reports, BAW-10010 Part 1, Stability Margin for Xenon Oscillations Model Analysis, August 1969; BAW-10010 Part 2, Stability Margin for Xenon Oscillations - One

Dimensional Digital Analysis, February 1970; and BAW-10010 Part 3, Stability Margin for Xenon Oscillations - Two and Three Dimensional Analysis, April 1970. These analyses indicated that, while azimuthal and radial xenon oscillations are not divergent, axial xenon oscillations could be divergent at the beginning of the fuel cycle. The analyses further indicated that axial xenon oscillations which are slow changes taking place over several hours can be controlled by having the reactor operator change the position of the eight part-length axial power shaping rods. In addition, the applicant agreed to perform tests during the initial startup of Oconee Unit 1 to demonstrate the stability of the core against xenon-induced reactivity fluctuations.

As added assurance that power maldistributions will not go undetected should they occur, the Technical Specifications (1) require axial and radial power distribution monitoring and control measures to be in effect, and (2) limit the BOL positive moderator coefficient.

On the basis of the review, and with the restrictions imposed by the Technical Specifications, the staff concluded that the nuclear design is acceptable.

4.2.6 Fuel Densification

The staff is continuing its review of the fuel densification phenomenon and the associated effects. At this time, the staff has reviewed and accepted, with modifications, the B&W evaluation model for prepressurized fuel, the type of fuel used in the Oconee Unit 1 reactor and others like it including the Oconee Units 2 and 3 reactors. Furthermore, the staff has completed its review of the fuel densification matter for the Oconee Unit 1 reactor and has concluded that Oconee Unit 1 can be operated at rated power but required that certain Technical Specifications be changed to some extent in the more conservative direction. These changes include a 2% reduction in the overpower trip setting and more restrictive core power imbalance limits which will reduce the power maneuverability of the plant somewhat.

With the conclusion of the staff fuel densification review of the Oconee Unit 1 prototype reactor, the applicant for Oconee Units 2 and 3 submitted a final fuel densification analysis report. For the Oconee Units 2 and 3 fuel densification analysis the applicant used the B&W evaluation model which the staff found acceptable for Oconee Unit 1. On the bases of the staff review to-date of the information provided by the applicant, the staff has concluded that the applicant has utilized acceptable methods for the analysis and has accounted properly for design differences between the Oconee Unit 1 prototype reactor and the Oconee Units 2 and 3 reactors. The principal difference between Oconee Unit 1 and Oconee Units 2 and 3 in this design matter is that the initial density of the Oconee Unit 1 fuel is slightly greater than for Oconee Units 2 and 3. The staff concurs with the applicant's conclusion that Oconee Units 2 and 3 can be licensed to operate at rated power with suitable operating restrictions to be established in the Technical Specifications. These restrictions will be of the type established for Oconee Unit 1. The final values will be established on the basis of our continuing detailed review of the information submitted by the applicant.

4.2.7 Reactor Internals

The staff reviewed the B&W topical reports BAW-10008, Part 1, Rev. 1, Reactor Internals Stress and Deflection Due to Loss-of-Coolant Accident and Maximum Hypothetical Earthquake, June 1970, and BAW-10008, Part 2, Rev. 1, Fuel Assembly Stress and Deflection Analysis for Loss-of-Coolant Accident and Seismic Excitation, June 1970. These reports were referenced in the Oconee application and outlined the methods of analysis employed for the internals and fuel assemblies under a LOCA and safe shutdown earthquake (SSE) loadings for skirt supported reactor vessels. The staff determined that these reports are acceptable for the Oconee Units 2 and 3.

4.2.8 Control Rod Drives

Motor Extension Tube Defects

During assembly of control rod drive motor (CRDM) extension tubes for B&W plants like Oconee, some motor extension tubes exhibited localized variations in wall thickness and discontinuities on the inner surface, not detected by ultrasonic testing techniques certified to be in accordance with ASME Code, Section III. The applicant's subsequent investigations included metallographic and chemical examinations, specialized ultrasonic inspection techniques and fracture mechanics analysis.

Tubes meeting the Code-required minimum wall thickness based on the original design temperature of 650°F and having no indicated discontinuities deeper than 5% of the nominal-finish wall thickness were accepted and returned to the field for service.

Where wall thickness permitted, discontinuity indications greater than 5% of the nominal-finish wall thickness were reduced by honing the internal surface of the tubes while maintaining the ASME Code, Section III, Class 1 Components, paragraph NB-2558, required wall thickness based on the original design temperature. Tubes were then reexamined ultrasonically for discontinuity depth and for proper wall thickness.

The tubes withheld because of wall thickness were reevaluated based on a revised design temperature of 450°F. This approach was allowable by ASME Code, Section III, Class 1 Components, paragraph NB-3112.2. The actual maximum metal temperature which exists under the specified normal operating condition was determined by mockup testing and measurement at Oconee 1. The results are discussed below.

Special ultrasonic test inspection techniques were developed to accurately define the depth of discontinuities. Indicated discontinuity depths no greater than 5% of the nominal wall thickness are allowed by ASME Code, Section III, Class 1 Components, paragraph NB-2552.1.

A fracture mechanics analysis by Southwest Research Institute (SRI) has concluded that a 90 mil notch in the worst case longitudinal direction is acceptable for the design life of the tube. The staff concurred with the SRI findings.

The staff concluded that the motor tube extensions accepted under the criteria proposed by B&W have an adequate margin of safety and are acceptable.

With regard to the thermal safety margins (450°F vs 650°F), temperature test data presented by B&W verified that a substantial temperature safety margin exists. A maximum tube extension temperature of 234°F-378°F was measured when stator cooling was available. For the case of a loss-of-stator cooling plus stator "power-on" situation a 418°F maximum extension tube temperature was measured. This latter temperature along with heatup time cycles (when stator cooling is lost) on the order of 75 minutes to 5-1/2 hours, confirmed B&W's previously stated position that a loss-of-stator cooling situation would not lead to excessive tube extension temperatures.

Based on this information, the staff concluded that the 450°F design temperature for the CRDM extension tubes provides a suitable safety margin with respect to anticipated operating temperatures and hypothesized failure modes.

B&W stated that an inservice temperature testing and surveillance program will be implemented on Oconee 2, one of the first facilities utilizing these CRDM extension tubes with a 450°F design temperature.

This matter was reported by B&W in a topical report, BAW-10047, Rev. 1, A Study of Discontinuities in Control Rod Drive Motor Tube Extensions, August 1972. The staff reviewed this report and found it acceptable. The staff investigation included a field trip to Diamond Power Specialties Company to review the proposed repair procedures for the control rod drive motor tube discontinuities.

Current plans are that no modified (450°F) motor tubes will be used in Oconee 1, but they will be used in Oconee 2. The staff will follow the inservice temperature testing and surveillance program.

Drive Mechanism Damage

During control rod drop tests conducted in Oconee Unit 1, eleven control rod drive mechanisms sustained internal damage when they were tripped with their hydraulic snubber regions either completely dry or only partially filled with water. The applicant evaluated this situation in a report, Description of Cause and Correction of Damage to Control Rod Drive Mechanisms During Preoperational Testing of Oconee No. 1, September 29, 1971, and concluded that the primary cause of this incident was inadequate operating procedures for the existing conditions in that these procedures failed to incorporate basic precautions necessary to prevent gas accumulation under the reactor vessel head during certain preoperational tests. The applicant committed to take corrective action through operating procedures, design changes and a startup test program which the staff found acceptable. In addition, a technical specification was added to set a limit on the reactor coolant maximum permissible total gas concentration as a function of reactor coolant system pressure and temperature.

4.3 Fuel Design

The applicant eliminated the use of unpressurized fuel in all Oconee units. The unpressurized fuel which was to be used in the first core for Oconee Unit 1 and later recycled into the first core for Oconee Unit 3 was prepressurized prior to fuel loading in order to minimize the effects of fuel densification.

5.0 REACTOR COOLANT SYSTEM

5.1 General

Since the staff review and evaluation contained on pages 20-32 of the Oconee Unit 1 SER, Oconee Unit 1 suffered damage to the steam generators and the vessel internals during hot functional testing. Failure of and damage to vessel internals is believed to have been caused by flow induced vibration, and damage to the steam generators was caused by loose parts resulting from the vessel internals failures. B&W assessed the failures and damage and analyzed the cause through extensive examination, laboratory and full scale tests and system mockups. The results of this assessment and analysis were reviewed by the staff. In addition, B&W redesigned the vessel internals to prevent a recurrence of this type of failure and damage in Oconee Unit 1. The staff reviewed these redesigns. The damage to Oconee Unit 1 was repaired using the new design. B&W provided an extensive vibration and loose parts monitoring program during continuation of hot functional tests in Oconee Unit 1 to assure that the system response was safely within the new design predictions and limits. The staff reviewed this program. Supplement No. 2 to the Oconee Unit 1 SER provided the staff evaluation of the redesigned vessel internals components and vibration monitoring program. Since the issuance of Supplement No. 2, the staff confirmed that the new designs were conservative by a review of the vibration test data from

Oconee Unit 1 preoperational tests. The results and application to Oconee 2 and 3 are reported below.

5.2 Reactor Coolant System Components

5.2.1 Vessel Internals

Following completion of vibration testing on the Oconee Unit 1 reactor vessel internals during preoperational tests, the applicant submitted a report, Results of Oconee 1 Hot Functional Testing, Internals Vibration Monitoring Program, to the staff. This report confirmed the design adequacy of the Oconee Unit 1 reactor vessel internals as presented in the Topical Report BAW-10051, Revision 1, Design of Reactor Internals and Incore Instrument Nozzles for Flow-Induced Vibration, September 1972. The staff reviewed the data in these reports and visited the site during the post test surface inspection of the vessel internals and found that 1) the vessel internals are conservatively designed; 2) acceptable margin exists between measured internal structure responses and the respective allowables; and 3) no evidence of structural degradation was observed during the surface inspection of the internals structures following the test program carried out in accordance with Regulatory Guide 1.20, Vibration Measurements on Reactor Internals. Based on this examination the staff concluded that the design adequacy of the redesigned internals of Oconee Unit 1 was acceptably demonstrated.

By Amendment No. 41 to its application for an operating license for Oconee Units 2 and 3, the applicant provided BAW-10039 - Prototype Vibration Measurement Results for B&W's 177 Fuel Assembly, Two Loop

Plant, April 1973. This report presented the results of the prototype vibration measurement program conducted at the Oconee Nuclear Station, Unit 1, for the purpose of justifying the use of Unit 1 internals as the prototype reactor internals for all plants of this type and to present the documentation required by Regulatory Guide No. 1.20, Vibration Measurements on Reactor Internals. The staff reviewed this report and found it acceptable for application to Oconee Units 2 and 3 because these reactor systems and vessel internals are identical to Oconee Unit 1. In BAW-10039 results of a prototype preoperational vibration test conducted at Oconee 1 were presented by B&W for verifying the design adequacy of B&W 177-fuel-assembly, two-loop, reactor internal structures to withstand flow-induced vibration under plant operation conditions. A total of forty strain gages were installed on instrument nozzles, guide tubes, thermal shield support bolts, and the plenum cylinder. A total of ten accelerometers were used to monitor the response to the thermal shield, flow distributor and reactor vessel. Eleven pressure transducers were mounted on the thermal shield and core support shield; and 8 pressure sensing lines were employed on the instrument nozzles and guide tubes. The plant was tested under various operation flow transients induced by pump combinations with a temperature and pressure range up to 530°F and 2155 psig, respectively. Vibration predictions were presented in topical BAW-10051, Design of Reactor Internals and Incore Instrument Nozzles for Flow Induced Vibration, September 1972. For the thermal shield, modal responses were based on conservatively assumed amplitudes. For other component structures subjected to a lateral flow component, equivalent static loads based on conservative cross flow velocity and dynamic amplification factors based on vortex frequency and the lowest resonant frequency of the component structure were used. A separate model flow test as described in BAW-10037, Revision 2, Reactor Vessel Model Flow Tests, November 1972, and a component flow test consisting of instrumented guide tube and nozzle assemblies were conducted and compared with the preoperational test results. The subsequent visual inspection along the major load bearing paths of the internals were described in BAW-10038, Revision 1, Prototype Vibration Measurement Program for Reactor Internals, November 1972. Preoperational test results concluded that all responses were far below the predicted values and the reactor internals substained the various flow-induced vibration encountered during service.

The staff reviewed BAW-10039 and the related information and found that the prototype preoperational vibration testing program conducted at Oconee 1 adequately demonstrated the structural integrity of the reactor internals to withstand flow induced vibration under normal operation conditions. The review and evaluation included confirmation of the vibration prediction analysis, instrumentation, testing procedures, and the subsequent inspection program. BAW-10039, BAW-10037, 10038 and 10051 provide the necessary information to meet all requirements of Regulatory Guide 1.20.

Plots of power spectral density function for signals obtained from the sensors on the thermal shield and its lower bolts provided a definitive measure for describing the random nature of thermal shield response.

BAW-10039 and the related information from topical reports BAW-10037, BAW-10038 and BAW-10051 provided an acceptable basis for establishing the Oconee Nuclear Station Unit 1 as the prototype for similarly designed 177-fuel-assembly, two-loop plants.

5.2.2 Components

Additional analyses of the reactor coolant system by the staff confirmed that the stress levels calculated under loads from the DBA and SSE and the combination of these events were within the acceptable emergency and faulted stress limits, respectively, of current component codes.

In accordance with Paragraph 1701.5.4 of the ANSI B31.7 Nuclear Power Piping Code, which requires that piping shall be supported to prevent excessive vibration under startup and initial operation conditions, a vibration operational test program was performed during startup and initial operating conditions in Unit 1. These tests verified that the piping and piping restraints within the reactor coolant pressure boundary (RCPB) are designed to withstand dynamic effects due to valve closures, pump trips, etc.

The tests developed loads similar to those experienced during reactor operation and provided an acceptable basis for conducting the vibration operational test program.

The applicant stated that reports documenting these tests on Oconee Unit 1 will be submitted for the staff review. The applicant further stated that the procedures for these tests are the same as those to be used for Oconee 2 and 3 whenever operational reports indicate excessive displacement or vibration in components of these units, and that any corrective measures taken in Unit 1 will be taken in Units 2 and 3 also.

5.2.3 Materials

Fracture Toughness

To assure that ferritic materials of the pressure-retaining components of the reactor coolant pressure boundary exhibit adequate fracture toughness under normal reactor operating conditions, system hydrostatic tests, and during transient conditions to which the system may be subjected, the staff reviewed materials testing and operating limitations proposed by the applicant.

The applicant stated, in Amendments Nos. 32 and 33 of the FSAR, that acceptance testing for ferritic materials was performed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition, including all addenda through summer 1967. Dropweight nil ductility tests (NDT) data as well as

Charpy V-notch energy curves were obtained for the plates and major forgings in the reactor vessel; materials test results were submitted in these amendments.

To establish operating pressure and temperature limitations during startup and shutdown of the reactor coolant system, the applicant agreed to follow Appendix G, Protection Against Nonductile Failure, of the 1972 Summer Addenda of the ASME Code, Section III. The applicant submitted specific operating limitation curves.

The staff concluded that the planned operation of the reactor coolant system will assure adequate margins of safety.

5.2.4 Reactor Vessel Materials Surveillance Program

A materials surveillance program is required to monitor changes in the fracture toughness properties of the reactor vessel material as a result of neutron irradiation.

The six surveillance capsules for Unit 2, as described in Amendment No. 32 of the FSAR, have been delivered to the site. These capsules were fabricated before the proposed AEC §50.55a, Appendix H, was published and therefore contain all of the presently required weld impact specimens in only three capsules; the staff currently requires five such capsules. The program does comply with ASTM E185-70. The applicant adjusted the withdrawal program for the Unit 2 capsules to obtain maximum information from the available specimens.

The applicant stated in Amendment No. 32 of the FSAR, that the material surveillance program for Unit No. 3 will comply with the proposed AEC §50.55a, Appendix H, Reactor Vessel Material Surveillance Program Requirements, and ASTM E185-70. The program specification is acceptable with respect to the number of capsules, number and type of specimens, withdrawal schedule, and retention of archive material.

The staff concluded that the proposed program adequately monitors neutron radiation induced changes in the fracture toughness of the reactor vessel beltline material for Units 2 and 3.

5.2.5 Flood Line Flow Restrictor

By FSAR Supplement No. 14, Revision 26, Amendment No. 39 to the application for operating licenses, the applicant provided a description and analysis of the flood line flow restrictors installed in all Oconee Units to improve ECCS performance during a flood line break LOCA.

The staff reviewed the mechanical and materials aspects of the flow restrictor in the core flooding nozzle, including design consideration, fabrication and installation procedures. This flow restrictor replaced the existing thermal sleeve and was installed by welding. All applicable thermal and flow-induced transient loadings were considered in the stress and fatigue evaluations on the weld and the restrictor design. The applicant stated that all applicable requirements of the ASME Section III Code were met. The staff concluded that the use of the ASME Section III Code requirements provided an acceptable basis for design, fabrication and installation of the core flooding nozzle flow restrictors.

5.3 Evaluation of Other Class I (Seismic) Mechanical Equipment

5.3.1 ASME Code Classes 2 and 3 Components

Seismic Class I systems, components, and equipment were designed, fabricated, and examined, as applicable, to the ASME Boiler and Pressure Vessel Code, Sections III, VIII, ANSI B31.7, MSS-SP61, and B16.5; and TEMA and ASTM Standards.

The staff concluded that the codes and standards specified for seismic Class I tanks, heat exchangers, piping, pumps and valves provide an acceptable quality level and are consistent with recently reviewed plants of this type.

All seismic Class I systems, components, and equipment comparable to ASME Code Classes 2 and 3 outside of the reactor coolant pressure boundary were designed to sustain normal loads, anticipated transients and the Operational Basis Earthquake within the appropriate code allowable stress limits and the Safe Shutdown Earthquake within stress limits which are comparable to those associated with the emergency operating condition category. The staff concluded that these stress criteria provide an adequate margin of safety for seismic Class I systems, components and equipment.

5.3.2 Seismic Input

The seismic design response spectra curves were presented in the PSAR and approved prior to the issuance of the construction permits for the Oconee Nuclear Station. The modified earthquake time histories used for component equipment design were adjusted in amplitude and frequency to envelope the response spectra specified for the site. The staff and its seismic design consultants concluded that the seismic input criteria proposed by the applicant provided an acceptable basis for seismic design.

5.3.3 Seismic System Dynamic Response

Modal response spectrum multi-degree-of-freedom and normal mode-time history methods were used for the analysis of all Class I structures, systems and components. Governing response parameters were combined by the square root of the sum of the squares to obtain the modal maximum when the modal response spectrum method was used. The absolute sum of responses was used for closely spaced frequencies. Horizontal and vertical floor spectra inputs used for design and test verification of structures, systems, and components were generated by semi-empirical methods and confirmed by the normal mode-time history method. Constant vertical load factors were employed only where analysis showed sufficient vertical rigidity to preclude significant vertical amplifications in the seismic system analyzed. The staff and its seismic design consultant concluded that the seismic system dynamic methods and procedures used by the applicant provided an acceptable basis for the seismic design.

5.3.4 Criteria for Seismic Instrumentation Program

The type, number, location, and utilization of strong motion accelerographs to record seismic events and to provide data on the frequency, amplitude and phase relationship of the seismic response of the containment structure correspond to the recommendations of Regulatory Guide 1.12, Instrumentation for Earthquakes.

Supporting instrumentation was installed on class I structures, systems, and components in order to provide data for the verification of the seismic responses determined analytically for such class I items.

The staff concluded that the Seismic Instrumentation Program proposed by the applicant is acceptable.

5.5 Inservice Inspection

The staff evaluation of inservice inspection, is reported in the Oconee Unit 1 SER (pages 29 & 30). The applicant has provided additional information regarding a program to comply with the staff Recommended PWR Inservice Inspection Program for Detection of Effects of Reactor Coolant Leakage. The Technical Specifications specify leak tight integrity of the reactor coolant system and specify leak detection requirements which comply with the intent of the staff recommended program. Since the Technical Specifications require that any reactor coolant leakage evaluated as unsafe (no matter how small) is cause for shutdown and corrective action, the staff concluded that protection against corrosive leaks is inherent in the applicant's program and is acceptable.

5.7 Testing of Active Valves

By letter of January 2, 1973 the applicant was requested to provide information regarding the operability of active valves which form a part of the reactor coolant system boundary. The applicant responded with a report by letter dated May 1, 1973, Oconee Units 2 and 3 Active Valve Operability.

Active valves whose operation is relied upon to safely shut down and maintain the plant in a safe condition in the unlikely event of a safe shutdown earthquake or a loss-of-coolant accident must be designed and tested to criteria which assure that these components will function properly during and after all design basis events. The applicant identified the active valves within the reactor coolant pressure boundary and listed the applicable design and operating conditions. Seismic analyses for the specific piping systems in which these valves are located were performed to determine the severity of seismic loads. Vibration testing was utilized to confirm the capability of certain valve operators to sustain dynamic loading. Environmental tests, including heat, steam, and chemical effects, were conducted in some instances on complete valve assemblies and most significantly, on all appropriate electric motor operators. In addition, hydrostatic testing, leak testing, and performance cyclic testing were also conducted. The staff concluded that the design and test programs utilized provided acceptable assurance that the active valves identified are inherently capable of performing their design safety functions under the mechanical loads and environmental conditions associated with the design basis events for Oconee Units 2 and

3. The applicant further agreed to remain cognizant of industry efforts to identify potential valve operability generic problems and to incorporate, if necessary, appropriate modifications that could improve or correct active valve performance under conditions required for their intended design safety function.

5.8 Loose Parts Monitoring

In keeping with the commitment made in the applicant's FSAR, the applicant installed a loose parts monitoring system utilizing accelerometers applied to the two steam generator upper heads and the reactor vessel lower head on Oconee Unit 1. Signals from the crystal type accelerometers are conditioned by preamplifiers filtered to reduce normal plant noise and are recorded on magnetic tape in the control room. The signals are continuously monitored over a speaker and, to provide the plant operator with an immediate warning of abnormalities, an alarm is set to trip by preselection of level on a decibel meter. All sensors and channels are redundant (two for each location) and tape playback provides a means for analyzing signals from all channels. Systems similar to the one installed on Unit 1 will be installed on Units 2 and 3.

The staff witnessed the system installed in Unit 1 and will continue to evaluate the experience gained during operation of the Oconee Units.

6.0 REACTOR BUILDING AND CLASS I (SEISMIC) STRUCTURES

6.1 General Structural Design

The results of the earlier review and evaluation by the staff are discussed on pages 33-38 of the Oconee Unit 1 SER. Since that earlier review and evaluation, the staff had the benefit of reviewing the Oconee Unit 1 reactor building structural acceptance tests and leakage tests. The applicant was asked to provide additional information in this area so that the staff could perform a supplemental evaluation for Units 2 and 3 as discussed below.

The seismic Class I structures of the facility include the reactor buildings and their internal structures; the auxiliary buildings; and the dam and spillway complex.

The reactor buildings are steel lined prestressed concrete structures in the form of vertical right circular cylinders with flat bases and flat spherical domes. The structures interior to the reactor building are typically of reinforced concrete construction with details typical to PWR type nuclear power plants. The structures external to the reactor buildings are, likewise, typical nuclear power plant configurations.

The Class I structures were designed for the usual wind, tornado, seismic, dead, live, buoyant, earth pressure, accident and operating loads.

The reactor buildings were designed to withstand a 59 psig design pressure and a concurrent peak accident temperature. Seismic loads resulting from operating basis and safe shutdown earthquakes were considered.

The reactor buildings were designed to withstand wind loading using the practice established in ASCE paper 3269. A tornado loading was also included. The tornado model was the simultaneous application of a wind with a 300 mph velocity and a decrease in atmospheric pressure of 3 psi in 5 seconds. The staff concluded that the methods for converting the wind and tornado velocities into loadings and the application of the loads are acceptable.

For Class I structures other than the reactor building the static analysis techniques employed were those conventionally applied in beam, frame, and thin shell analysis.

The design of concrete structures internal and external to the reactor buildings was accomplished in accordance with the provisions of ACI 318-63. Design of interior structures included consideration of local pressure and jet impingement loads.

All Class I steel structures other than reactor buildings were designed by the working stress method in accordance with the provision of the AISC Specification. Stress resultants were maintained below allowables.

The applicant designed all Class II structures that, through collapse, could damage Class I items to Class I standards or relocated such structures so that the safety function of Class I items would be unaffected by the failure of Class II structures. These procedures were similar to procedures approved for previously licensed facilities and are therefore acceptable to the staff.

6.2 Reactor Building Structural Design

The reactor building structures were designed in accordance with the provisions of the ACI-318-63 and supplementary criteria as established in the PSAR. The reactor building prestressing system consists of hoop and longitudinal prestressing tendons in the cylinder and meridional tendons in the dome. Radial shear in the cylinder is carried directly by radial reinforcing bars. In general, reinforcing bar splices were by the Cadweld process.

The reactor building structures were analyzed for axisymmetric loads using finite element theory. The finite element approach was also employed to evaluate the effect of non-axisymmetric loads. The general design and analysis procedures as prepared by the applicant and outlined above are appropriate and acceptable for the containments, since they are in accordance with the general practice of the profession.

Stresses resulting from analysis were summarized in tabular form in Section V of the FSAR. The stresses, lie within established allowables and are acceptable.

By letter dated October 25, 1972 the staff requested that the applicant reanalyze the ability of the reactor building to withstand the peak pressure which might be encountered during a loss-of-coolant accident. By Supplement 13 to the FSAR, dated January 29, 1973, the applicant performed analyses for a spectrum of breaks at various locations to ensure that the most severe break size and location were selected. The breaks producing the highest reactor building pressure were a 7 ft^2 split of the pump suction piping and the double-ended hot leg break which resulted in a reactor building pressure of about 54 psig. The design pressure is 59 psig. The staff reviewed the assumptions used by the applicant in this analysis and performed a confirmatory analysis for the 7 ft^2 split break.

The applicant calculated the mass and energy release rates to the reactor building using the CRAFT code for both the blowdown and reflood periods. The staff reviewed the assumptions used in this code and found them to be acceptable. In the staff analysis of reactor building pressure, the mass and energy release rates calculated by the applicant for the blowdown period were used. During the reflooding period, however, the staff used the FLOOD-2 code to predict the mass and energies to the reactor building. The staff calculated reactor building pressure using the CONTEMPT* code and calculated the same reactor building pressure as the applicant. The staff concluded that the design pressure of 59 psig is acceptable.

*AEC/ANC Containment Pressure Code

By letter, dated January 8, 1973, the staff requested that the applicant present the results of calculations of pressure differentials across the walls of compartments inside the containment.

By letter, dated March 2, 1973 the applicant presented the calculated pressure differential response in the reactor cavity for two breaks of a reactor coolant pipe; 3.0 and 8.0 square feet in an area, respectively. The results, as presented by the applicant, indicated that the 8.0 square foot break would result in a 195 psi peak pressure differential for the reactor cavity. The design value is 205 psi. The staff performed a similar analysis which provided results in agreement with the applicant and concluded that the design pressure of 205 psi is acceptable.

The applicant and the staff made independent calculations of the overpressure in the steam generator subcompartment resulting from a double-ended hot leg break and agree that the overpressure would be slightly less than 15 psi. The structure was designed for 11.1 psi overpressure. The applicant has provided an analysis of the structural capability of the subcompartment and concluded that it will withstand 15 psi with 30% margin. The staff will complete its review of the structural capability prior to operation of Oconee Unit 2.

The structural materials, construction techniques, and quality control were, for the most part, similar to those applied on other recent nuclear facility construction projects. A 500 psi concrete was used for the reactor building. Reinforcing steel conformed to

ASTM A-615 with Grade 60 used in the foundation slab and Grade 40 employed in the cylinder and dome for crack control. Full tension Cadweld splices were employed for bar splicing of reinforcing bars of greater than size no. 11. Conventional construction methods were used for this facility. The quality control procedures, which were similar in scope to those previously applied in other plants such as Point Beach, are acceptable to the staff for the Oconee Nuclear Power Plants.

6.3 Reactor Building Testing and Surveillance

The Oconee Unit 2 containment was pneumatically tested to 1.15 times the design pressure with gross deformation of the structure being recorded. Taut wire systems, identical to the one employed for Unit 1, were used for Unit 2 and will be used for Unit 3. The staff finds this acceptable.

7.0 ENGINEERED SAFETY FEATURES

The staff evaluations of the engineered safety features of the Oconee Unit 1, contained on pages 39-48 of the Oconee Unit 1 SER and its Supplement No. 1 are applicable to Units 2 and 3. Additional information is presented below.

7.1 Emergency Core Cooling System

The staff review and evaluation of the Oconee Unit 1 emergency core cooling system is presented in the Oconee Unit 1 SER (Pages 39-43). Because this review and evaluation was generic in nature and since the emergency core cooling systems for Oconee Unit 2 and Oconee Unit 3 as well as the reactor systems are identical to Unit 1, the staff conclusions regarding Oconee Units 2 and 3 are the same as those presented in the Oconee Unit 1 SER.

The staff issued Supplement No. 1 to the Oconee Unit 1 SER on March 24, 1972. This supplement included a description of the ECCS and the staff evaluation of its performance using the B&W Evaluation Model in conformance with the Interim Policy Statement, Appendix A, Part 4. The description of the ECCS contained in Supplement No. 1 to the SER is applicable to Oconee Units 2 and 3.

Several additional topics associated with emergency core cooling system performance were identified as a result of the staff review of the Oconee Units 2 and 3 operating license applications. These topics include: (1) the reflooding analysis associated with a loss-of-coolant accident; (2) the analysis of small breaks in the primary cooling system; (3) the analysis of a break in the core flooding tank (CFT) line; (4) a loss-of-coolant accident when operating with idle coolant pumps; (5) fuel densification; and (6) use of all pressurized fuel rods. This report gives the completed evaluation by the staff.

7.1.1 Reflood Analysis

General

The staff reviewed the applicant's reflooding analysis using a new carryover rate fraction* correlation developed by B&W during the course of the rulemaking hearing (Docket RM50-1) to account for the entrainment of reflooding water. The previous reflood analysis performed by B&W in report BAW-10034, Revision 3, Multinode Analysis of B&W's 2568 MWt Nuclear Plants During a Loss-of-Coolant Accident, May 1972, used an entrainment assumption of 20% of the inlet core flow rate. The 20% entrainment assumption was based on data obtained from the FLECHT ** program. The staff requested a reanalysis of the reflooding transient using the new CRF correlation in its letter to the applicant of November 3, 1972. Because the new carryover rate fraction correlation took many FLECHT experimental runs at different conditions into account, the staff viewed it as a better approach in calculating reflooding rates.

The staff reviewed the B&W reflood code (REFLOOD) and compared its results with those of the FLOOD 1 code (an ANC/AEC reflood program).

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*The carryover rate fraction (CFR) is defined as the total core flow rate out of the top of the core divided by the total mass flow into the bottom of the core.

** Full Length Emergency Core Heatup Tests

Reflooding rates predicted by both computer programs agree to within 1%, when the REFLOOD code uses the new carryover rate fraction to predict the entrainment. When the old entrainment assumption of 20% was used, the flooding rates calculated by REFLOOD were significantly higher than those predicted by FLOOD 1.

Results

B&W recalculated the reflooding rates and heat transfer coefficients for several break locations and sizes using the new carryover rate fraction correlation. The heat transfer coefficients used in determining the peak clad temperature were determined from the FLECHT correlation presented in WCAP-7665,* with the new, lower reflooding rates. Peak cladding temperatures calculated by the new reflooding rates are higher, and remained at elevated temperature for longer time periods. However, both the maximum clad temperatures and the percent metal-water reaction calculated were within the limits set forth by the Interim Policy Statement on ECCS.

The staff also requested on November 3, 1972 analyses of the effect of a higher elevation axial flux peak (the previous analyses were done for an inlet flux peak). The higher elevation peak (modified cosine flux peak) resulted in a slightly lower peak cladding temperature, but a greater metal-water reaction. The greater metal-water reaction is due to the extra time required for the ECCS fluid to advance to the higher elevation.

*WCAP-7665, PWR FLECHT FINAL REPORT, April, 1971

The following summarizes the results calculated using the carryover rate fraction entrainment correlation for the Oconee Units at 102% of rated power level (2568 MWt).

Cold Leg Pipe Breaks			Metal-Water Reaction, %	
Area	Type Break	Peak Cladding Temperature	Local	Core
8.55 ft^2	Double Ended	2082	2.11	0.075
8.55 ft^2	Split	2186*	2.98	0.09
8.55 ft^2	Split (cosine flux peak)**	2135	4.2	0.24
5.13 ft^2	Double Ended	2029	1.8	0.058
3.0 ft^2	Split	1728	0.046	0.01
0.5 ft^2	Split	1660	0.22	0.004
Hot Leg Pipe Breaks				
14.1 ft^2	Split	1670	0.14	0.003

*Limiting Case
**All other cases are an inlet flux peak

Conclusions

The use of the new carryover rate fraction correlation provided a more conservative method of predicting reflood water entrainment than the 20% entrainment assumption since the use of this correlation resulted in lower reflooding rates, higher peak cladding temperatures and greater metal water reactions. The staff concluded that, based on the present experimental data, the use of this more conservative approach was warranted. The staff further concluded that the ECCS performance analysis using this more conservative approach meets the acceptance criteria, as described in the Commission's Interim Policy Statement.

7.1.2 Small Break Analysis

General

The Interim Policy Statement concerning emergency core cooling in the event of a LOCA required the analysis of LOCA's over the entire break spectrum. The B&W evaluation model in Part 4 of Appendix A to that statement specified an acceptable evaluation model for break sizes from 0.5 ft^2 up to and including the double-ended severance of the largest pipe of the reactor coolant pressure boundary (the large break model). B&W submitted a Topical Report, BAW-10052, Multinode Analysis of Small Breaks for 2568 MWt Plants, September 1972, to present an evaluation model for breaks less than 0.5 ft^2. The staff completed the evaluation of this report.

In general, small breaks are less limiting accidents than the larger design basis breaks. The B&W reactor design used in Oconee contains internal vent valves which further mitigate the LOCA consequences, including those caused by small breaks. For cold leg breaks these vent valves prevent a hot leg loop seal from forcing the water level in the core to drop excessively due to steam binding. A low water level in the core could cause a core heatup transient due to degraded heat transfer. By venting the reactor upper plenum to the downcomer annulus, the steam generated by depressurization and by core heat transfer can bypass the hot leg flow path, if blocked by a water seal, and flow through the vent valves out the cold leg break to the reactor building.

Small Break Model

B&W developed a procedure for analyzing the consequences of small breaks which differed somewhat from that given in BAW-10034, Revision 3. This procedure was similar to those used for large breaks but was different in some aspects to account for a more tranquil hydrodynamic response of the systems for smaller breaks. These differences between the small break model and the large break model have been reviewed and evaluated.

The CRAFT code* was used to simulate the hydrodynamic response for both the large and the small break models. The number of nodes representing the primary system for the small break model was reduced to 11, with one node for the secondary system and one node for the reactor building. Additionally, the Redfield variable bubble rise model** described in BAW-10030 and BAW-10034 was used in all nodes whereas the large break model assumed a zero bubble rise model in the lower head, the core, the upper plenum and the pump suction nodes. For a large break analysis this zero bubble rise model was more appropriate for those nodes where good mixing occurs due to the rapid depressurization and high flow rates.

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*BAW 10030 CRAFT - Description of Model for Equilibrium LOCA Analysis Program, October 1971.

**Ref 1; A zero bubble rise velocity yields a homogeneous node, while increasing the bubble velocity tends to separate the water phases.

Note: References are at the end of Section 7.0 of this report.

For the associated heat transfer analysis a THETA* model, slightly smaller in nodalization, was used during the flow-controlled heat transfer transient. For one case examined, this change resulted in only a 7°F difference (in the conservative direction) between the small break THETA model and that used for large break analysis. When core flow drops below 1% of its initial value and flow no longer controls heat transfer, another heat transfer code QUENCH** was used. QUENCH was a one axial node, one clad node, and one fuel node code; it assumed heat to be transferred by either pool film-boiling, or by forced convection to steam. Multiple QUENCH runs were made at various axial locations to obtain the thermal response of the fuel rod. Morgan's correlation for pool film boiling (Ref. 2) was used for that portion of the core covered by a mixture of steam and water. This correlation was the best available for pool film boiling from vertical surfaces. It was derived from a theoretical model of the stable annular flow regime as compared to the dispersed flow film boiling regime, and therefore it was conservative in this regard. The correlation under-predicted the available data for pool film boiling from vertical surface for a variety of fluids. The Dittus-Boelter correlation*** was used for

*Fuel element heatup calculation - IN-1445, THETA 1-b, A Computer Code for Nuclear Reactor Core Thermal Analysis, February 1971.
**BAW Computer code described in BAW-10052.
***Dittus, F.W., Boelter, L.M.K. Heat Transfer in Automobile Radiators of the Tube Type, published in Eng., Vol. 2, - 13, University of California, pp. 493-461, 1930.

that part of the core covered by steam. In the steam-flow region the average steam flow was conservatively calculated for the fuel heatup calculation, with the fluid temperature calculated by hand.

A major difference between the small break model and the large break model was the absence of any arbitrary bypass in the small break model of core flooding tank (CFT) injection water prior to the end-of-blowdown. The CFT bypass assumption was unduly conservative in small break analysis since the velocity of fluid in the downcomer was too low to entrain CFT injection water and sweep it out the break.

Since the core is never completely uncovered for small breaks, the reflood analysis (which is performed for larger breaks) was not done. The reflood analyses and the previously discussed CFT bypass assumption are, however, interrelated. A comparison of a 0.5 ft^2 break analyzed by both the large break model (CFT bypass assumption) and the small break model was conducted by B&W. The two models agreed very well until the CFT bypass assumption was imposed for the large break model. This resulted in a calculated peak clad temperature of 1660°F in the reflood transient associated with the large break model, compared to a peak clad temperature of only 710°F using the more realistic, yet conservative small break model.

Results and Conclusions

The results of B&W's small break analysis for plants at a core power of 2568 MWt ~~were~~ are contained in B&W topical report BAW-10052.

A summary of these results is given below:

Break Size and Location	Peak Clad Temperature, °F	Long Term Cooling Established*, sec
0.5 ft^2 (pump discharge)	710	400
0.3 ft^2 (pump suction)	780	1100
0.1 ft^2 (pump suction)	826	2500
0.1 ft^2 (pump discharge)	720	3400
0.04 ft^2 (pump suction)	978	3000

All conditions of the Interim Acceptance Criteria were met; the peak clad temperature was well below 2300°F, there was little or no metal-water reaction, the core geometry was still coolable and long term cooling was established. On the basis of the evaluation of these analyses, the staff determined that the emergency core cooling system does provide adequate protection for small breaks in the primary cooling system.

7.1.3 Core Flooding Tank Line Break

General

This postulated accident involved the double-ended break of one of the two lines which connect a core flooding tank (CFT) to the reactor vessel. These lines also connect the low pressure injection (LPI) piping to the reactor vessel. Assuming no offsite power and a single active failure (such as in one of the buses supplying emergency

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* Long-term cooling is established in the applicant's opinion when the core is covered with mixture, more water is being supplied than leaked, the pressure is stabilized and the cladding temperature is falling.

power), the ECCS is degraded to only one CFT and one high pressure injection (HPI) pump. This postulated accident is particularly severe if sufficient water to cool the core does not remain in the reactor vessel during this accident because the capacity of one HPI pump, considering the need to reflood the core and also to supply sufficient make-up water to compensate for decay heat and stored heat in the primary system, is marginal.

In order to retain more water in the vessel during this accident, the applicant installed flow limiting orifices (see Flood Line Flow Restrictors, Section 5.2.5) in the nozzles of the CFT lines. This modification reduced the break size from 0.72 ft^2 to 0.44 ft^2 and by B&W's calculations, allows several more feet of liquid to remain in the core during this accident. The applicant in Amendment 39 to its application dated January 29, 1973 submitted an analysis showing the effects of the flow restrictors for this accident. A summary of these results is presented below.

In evaluating the consequences of this accident, the staff conducted independent calculations using the RELAP,* TOODEE** and SWELL*** computer codes, with assistance from our consultant, Aerojet Nuclear Corporation (ANC). A summary of these independent calculations is included below also.

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* RELAP-3 "A Computer Program for Reactor Blowdown Analysis," IN-1321, June 1970.

** J. A. McClure, TOODEE - a Two-dimensional Time Dependent Heat Conduction Program, IDO-17227, April 1962.

*** Two phase level swell program recently developed by ANC.

Applicant's Analysis

The applicant supplied the results of an analysis of a postulated CFT line break accident for an Oconee reactor in Amendment 39 to the application dated January 29, 1973. In conducting this analysis, the applicant used the small break evaluation model described in BAW-10052. There were several changes to this small break model for the CFT line break analysis due to the unique break location. The most significant changes involved two additional nodes in the downcomer annulus and increasing the size of the core node to include most of the upper plenum volume.

One important parameter in this analysis was the amount of water remaining in the vessel during this transient. This determined the height of fluid in the core, and therefore, the heat transfer capability of the core and maximum cladding temperature. To determine the core water level, the applicant used three different CRAFT models to determine the sensitivity of the level prediction to noding. The different models provided good agreement with the lowest quasi-equilibrium liquid level approximately at the six foot elevation. When the liquid swell due to core heat generation was considered, the mixture (water and steam) level covered the core for most of the accident. In addition to these CRAFT models which used the Redfield bubble rise model, the applicant used a higher bubble rise velocity in one model which was more consistent with the two phase mixture height predicted by B&W's FOAM code (described below). This model prevented the two phase mixture from being lost by way of the vent valves out the break and the liquid level increased from the 6 foot to the 9-10 foot core elevation.

The applicant's calculations indicated that only the upper part of the core was not covered by mixture during this transient, but sufficient steam was generated by the covered portion to cool this uncovered part. Since the lower portion of the core was covered with a two-phase mixture, pool film boiling provides sufficient cooling and the maximum cladding temperature was calculated to occur in the upper uncovered portion of the core. The upper portion when not covered by mixture was cooled by forced convection to steam. To establish the maximum cladding temperature, the applicant investigated several axial power peaking shapes. A summary of these results is provided below:

Elevation of power Peak from the bottom of Core, ft	Elevation of Peak Cladding Temperature from the Bottom of core, ft	Peak Cladding Temperature, °F
5.5	5.5	731
7.8	11.4	964
10.6	11.4	1199

These cladding temperatures result in no significant metal-water reaction and the core geometry remains unchanged except possibly for some minor clad swelling in the case of the 10.6 ft power peak which would not be detrimental to core cooling.

Staff Calculations

An independent analysis of the core flood tank line break was performed by the staff to aid in the evaluation of this postulated accident. The analyses considered both the blowdown hydraulics and the heat transfer phenomena resulting from the predicted core water level.

The staff performed several blowdown analyses using the RELAP computer program (Ref. 3). These analyses included both a modeling study and a determination of the sensitivity of the analyses to the bubble rise model. To perform these studies, several system noding models were developed. A summary of these models is presented in Table 7-1. There were three basic models used in the analysis. The first (LARGE MODEL) was a 36 node model previously used to perform a large break analyses. This model used excessive computer time for small-break analyses, but it was used as the basic comparison model between other small-break models. This model had seven heat transfer nodes in each steam generator and three core nodes. It also had all cold and hot legs noded separately.

A second model (REDUCED MODEL) was generated to study azimuthal noding in the downcomer region. It consisted of 2 separate primary loops with the hot legs combined to reduce computer running time. Also the number of heat transfer nodes in the steam generators were reduced from 7 to 3.

TABLE 7-1

SUMMARY OF RELAP COMPUTER MODELS

Model Size	Number of Steam Gen Nodes	Number of Core Nodes	Number of Hot Leg Nodes	Number of Cold Leg Nodes	Number of Downcomer Nodes	Description
Large Model (36 Nodes)	7 in each	3	2	4	1	Basic Blowdown Model
Reduced Model (21 Nodes)	2 in each	3	2	2	1	Used to Perform Radial Downcomer Noding Study
Small Model (15 Nodes)	2 (Both Loops Combined)	3	1	1	1	Used to Perform Axial Downcomer Noding Study
Small Model	2 "	3	1	1	2	Homogeneous Downcomer
Small Model	2 "	3	1	1	2	Lower Downcomer Node Homogeneous Bubble Rise in Upper Node $V_B = 3$ ft/sec
Small Model	2 "	3	1	1	2	Lower Downcomer Node Homogeneous Bubble Rise in Upper Node $V_B = 5$ ft/sec
Small Model	2 "	3	1	1	4	All Downcomer Nodes Homogeneous
Small Model	2 "	3	1	1	1	Downcomer Node Bubble Rise
Small Model	2 "	3	1	1	2	Break Area = 0.44 ft^2
Reduced Model	2 "	3	2	2	4	All Downcomer Nodes Homogeneous
Reduced Model	2 "	3	2	2	8	All Downcomer Nodes Homogeneous

The third model (SMALL MODEL) was developed to perform downcomer axial noding studies. The two hot legs and 4 cold legs were combined to form a single loop with one steam generator containing two heat transfer nodes. To insure that each model predicted the same blowdown characteristic, the two smaller models were compared to the large 36 node model (standard model used for comparison). The pressure transients calculated by these three models are presented in Table 7-2. This table shows that each model predicted very similar pressure results.

After comparisons were performed, an axial noding study was made for the downcomer region using the small model. Investigations into the effect of using a bubble rise assumption (compared with a homogeneous assumption) and a number of downcomer nodes were performed. Also, the effect of bubble rise velocity (V_B) on the blowdown characteristics was investigated.

The first effect investigated was the assumption of using a bubble rise vs a homogeneous assumption for the downcomer. Two important differences were noticed when comparing these two models, each having a one-node downcomer, but one having a bubble rise assumption (V_B = 3 ft/sec) and the other using a homogeneous assumption. These differences were in the rate of depressurization and amount of water left in the vessel. Table 7-3 shows a comparison of the downcomer pressure vs time. The effect of using a bubble rise

TABLE 7-2
VESSEL PRESSURE COMPARISON
FOR
THREE STANDARD MODELS

Time Sec	Large Model 36 Nodes	Reduced Model 21 Nodes	Small Model 15 Nodes
0	2250	2250	2250
1	1597	1606	1604
2	1588	1617	1617
5	1583	1637	1637
10	1507	1504	1501
15	1327	1347	1345
20	1177	1153	1153
30	1101	1060	1060
40	1043	993	933
50	966	928	928
60	864	849	849
70	734	745	746
80	587	600	610
90	409	432	429
100	337	262	269

model was to extend the blowdown time. One other important difference was that the water remaining in the vessel for the homogeneous model during blowdown was reduced. A comparison of the water level in the vessel at 200 sec showed that the model assuming a homogeneous downcomer predicted 6308 lbs of water remaining in the vessel (to a height several feet below the core) while the bubble rise model predicted 83518 lbs ($\sim$ 7 ft into the core).

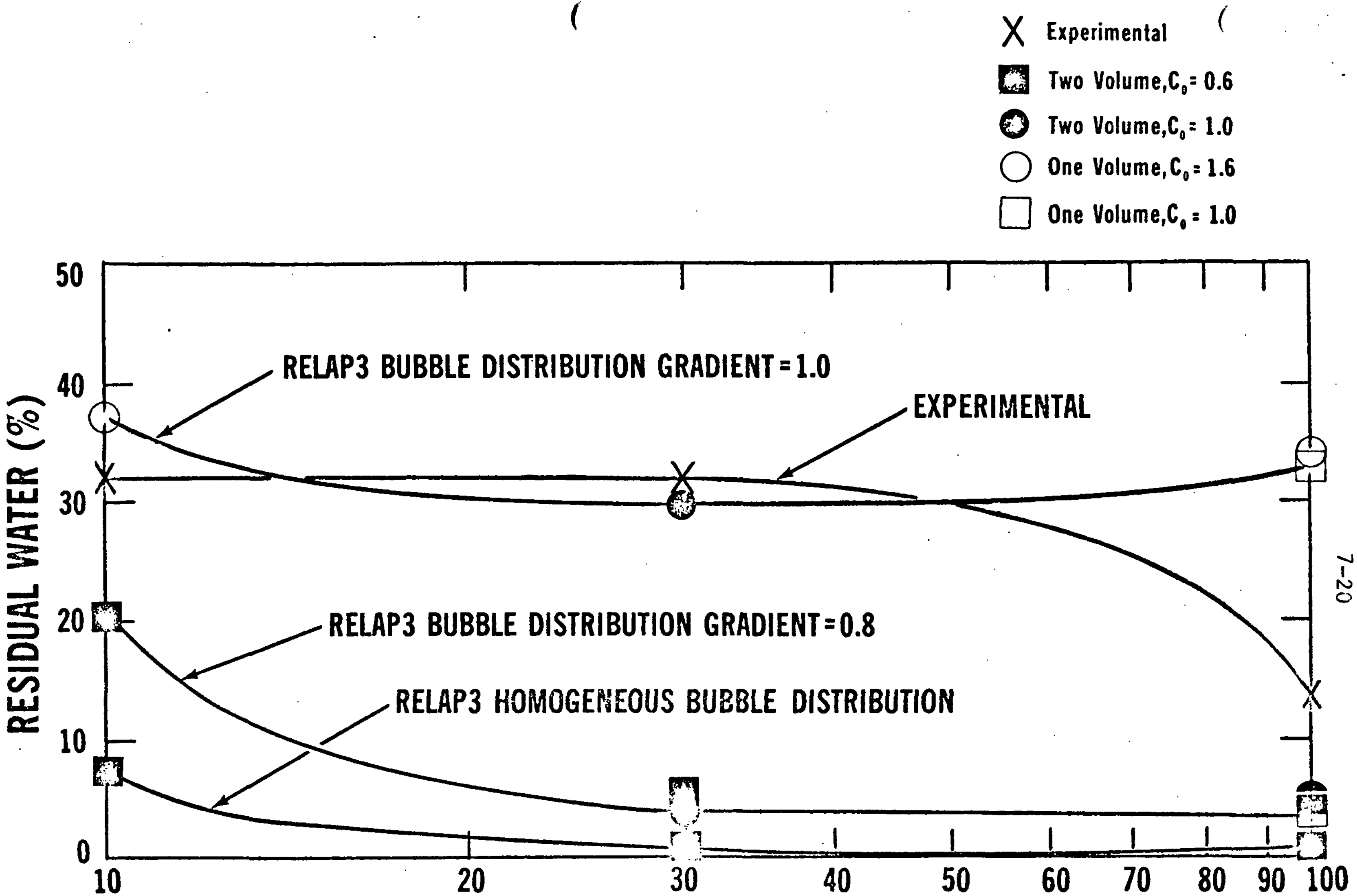
There were considerable differences in the results of analyses which assume either a homogeneous or a bubble rise model. The bubble rise model inherently assumed that phase separation occurred (separation between the steam and water phases). The homogeneous model assumed that phase separation did not occur. In a large break analysis the homogeneous assumption was closer to reality in the early part of the transient. Analyses performed by the staff (as well as B&W) showed that the CFT line break leads to a relatively gradual reduction in vessel pressure and low flow rates through the system. This was especially true after the first 20 seconds. From these analyses the staff concluded that phase separation occurred and a bubble rise model was appropriate for this analysis. This model led to a prediction of larger mass of water present during all stages of the transient relative to the homogeneous assumption. However, the homogeneous assumption used throughout the transient was not realistic and leads to a nonrealistic low quiet water level calculation.

TABLE 7-3
COMPARISON OF VESSEL PRESSURE
FOR
BUBBLE RISE AND HOMOGENEOUS ASSUMPTION

Time Sec	Pressure for Bubble Rise Model Assumption, psig	Pressure for Homogeneous Model Assumption, psig
0	2250	2250
10	1500	1500
20	1150	1150
30	1050	1060
40	970	990
50	890	930
60	800	850
70	720	750
80	620	610
90	510	430
100	410	270
110	340	160
120	280	80

Further support for the use of a bubble rise model was given in an Idaho Nuclear Corporation report (Report IN 1444, December 1970). In this report the RELAP code was used to predict results obtained from a semi-scale blowdown experiment. Figure 7-1 was taken from IN 1444 and shows that the residual water remaining in a vessel after the end-of-blowdown was best predicted by using a bubble rise model. The figure indicates that the density gradient should be between 0.8 and 1.0 with a bubble rise velocity of 3 ft/sec. Based on these results and calculations performed by the staff, a bubble rise model better predicts the actual system response.

One other conclusion drawn by B&W was that the CFT line break never led to an end-of-blowdown (as defined in the B&W evaluation model for a large break). In the downcomer noding studies performed by the staff it was concluded that end-of-blowdown could be calculated to occur by selecting 4 axial nodes in the downcomer and using a homogeneous assumption in all nodes. The end-of-blowdown occurred at about 120 seconds. The end-of-blowdown occurred because the cold core flood tank water entered into a node containing steam, which was then condensed, thus reducing the pressure below containment pressure. This node also contained the broken CFT line such that the reduction in pressure caused the break flow to go to zero (the definition of end-of-blowdown). This effect was investigated using the REDUCED MODEL with 2 axial nodes in the downcomer. An end-of-blowdown was



RESIDUAL WATER COMPARISON FOR SEMISCALE BLOWDOWN 700 SERIES

FIGURE 7-1

not predicted using this model. The staff concluded that the REDUCED MODEL was a better representation of the physical system.

The model chosen as the analysis tool to analyze the 0.44 ft^2 CFT line break was the SMALL MODEL using 2 downcomer nodes and bubble rise model. Vessel pressure and quiet water levels predicted by this model were compared with the B&W analysis. Pressure comparisons between the RELAP model and B&W small break model are presented in Table 7-4. Quiet water level comparisons were also made which showed good agreement between the two models. The staff considered the "quiet water level" calculated by the B&W model to be a best estimate of residual water left in the vessel.

One assumption used by B&W was that the accumulator bypass criterion should not apply to the CFT line break. B&W gave two reasons for making this change. The first was that the system pressure for the CFT line break never reached the end-of-blowdown criterion; the second reason was that the fluid velocity in the downcomer was always downward, except for short time periods. During these time periods the calculated velocities were low (maximum negative velocity was approximately 4 ft/sec). These low velocities do not cause any significant amount of ECC water to be entrained out the break. In the staff independent evaluation the same velocity effect was seen. A plot of downcomer velocity is presented in Figure 7-2 for a single node downcomer using a homogeneous assumption. This

TABLE 7-4
COMPARISON OF VESSEL PRESSURE
FOR
APPLICANT AND STAFF MODEL

Time Sec	Applicant's Model	Staff Model
0	2216	2216
50	1050	1020
100	800	800
150	575	530
200	450	412
300	320	255
400	250	210
500	180	170

figure shows a maximum velocity of $\sim$ 4 ft/sec for approximately 25 sec. Analysis reported by B&W using a three node downcomer and using a bubble rise model (also calculated by RELAP in the independent analysis) showed that the maximum negative velocity was approximately 4 ft/sec for about 100 sec. Critical velocity for entrainment from an annular film is about 13 ft/sec at 300 psia using the Wallis correlation (Ref. 4) given below.

$$j_g = 2.46 \times 10^{-4} \frac{\sigma}{\mu_g} \sqrt{\rho_f/\rho_g} \quad \text{where;}$$

j_g = vapor volumetric flow rate per unit area of pipe (Critical velocity for entrainment)

σ = surface tension

μ_g = vapor viscosity

ρ_g, ρ_f = density of the vapor and liquid

Based on these calculations, the staff concluded that the accumulator bypass assumption should not be applied to the CFT line break with a break area of 0.44 ft^2. This concept is discussed in the Concluding Statement of Position of the Regulatory Staff (Docket RM-50-1).

The boil off rate at about 200 seconds was approximately 5110 lb/min and the one HPI pump was supplying 4078 lb/min for most of the transient. The boil off was closely matched by the supply. Since the supply rate does not meet the Commission's "abundant emergency core cooling" criterion, the staff concluded that the applicant should have a method of supplying additional water for this postulated accident. This

SMALL MODEL RELAP RESULTS

OCONEE CORE FLOODING TANK LINE BREAK

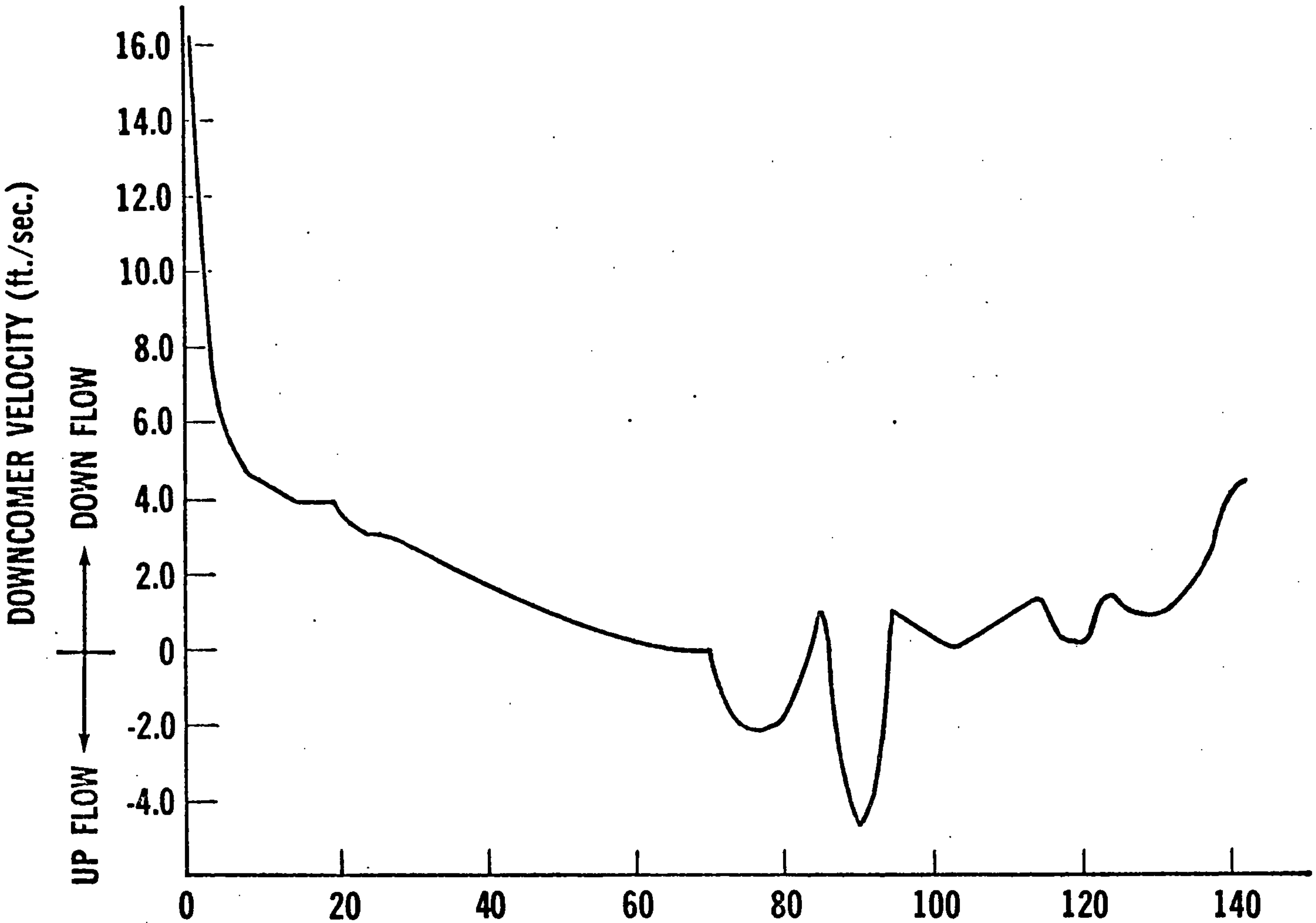


FIGURE 7-2

additional water should be supplied at a rate which would insure that the core would be reflooded at a reasonable rate.

To supply this additional water, the applicant instituted operating procedures to be used in the event of a LOCA. These procedures ensure that water from the low pressure injection (LPI) system is delivered into the reactor vessel for this accident. The operator is required to take action to rearrange the valving in the LPI system such that at least one-half the flow rate from the LPI pumps is injected into the vessel. This amount of additional water assures that an abundant supply of cooling water is available to reflood the core and remove stored and decay heat.

The staff reviewed the makeup of the Oconee operating staff and concluded that the shift staffing as specified in the Technical Specifications is sufficient to perform the necessary valving within 15 minutes following a LOCA so as to mitigate the consequences of this accident to acceptable levels.

Heat Transfer Analysis

B&W's fuel cladding heatup analysis for this accident is basically identical to that described in Section 7.1.2 for the small break analysis. Since the primary system never reached an end-of-blowdown condition, and water remained in the vessel, the reflooding analysis normally done was replaced by a heatup analysis using the THETA and

QUENCH codes with input from the blowdown codes, CRAFT, and the level swell code, FOAM.*

There were two major differences between the methods used for the CFT line accident and those used in the small break model. First, the level swell calculation was based on a Wilson (Reference 6) bubble rise calculation in the FOAM code. The small break model used the mixture level calculated in CRAFT. Second, the small break model assumed steam generation due to a mixture level 8 ft into the core, the minimum level for any transient. In the CFT line break, the mixture level calculated using FOAM was used for the steam generation calculation. However, the calculation still conservatively assumed the average assembly steam generation rate for the maximum heat generation rate assembly.

B&W compared their FOAM code to three sets of experimental data; a series of Westinghouse, General Electric and Japanese tests. The Westinghouse test (Reference 7) was contracted by the applicant for this explicit purpose and of the three tests utilized the largest number of simulated fuel rods (490) and the highest pressure (400 psia). The other tests, by GE and the Japanese (References 8 and 9), were based on a 49 rod BWR assembly at 100 psia and atmospheric

*B&W computer code described in BAW-10064 "Multinode Analysis of Core Flooding Line Break for B&W's 2568-MWe Internal Vent Valve Plants," April 1973.

pressure. However, neither the number of rods (49 or 490) nor the configuration (PWR vs BWR geometry) significantly affected the applicability of the data for verification of the FOAM code; in fact, the variations in these two parameters helped to define the insensitivity of the heat transfer/hydraulics phenomena and FOAM's prediction of the phenomena to these parameters. The comparisons of FOAM to the data were generally within the experimental uncertainty of the data except for several Westinghouse data points at 100 psig. For these data, the FOAM code overpredicted the measured swollen level by about 10%. This may be attributed to nonquantified uncertainty in some of the measured parameters, such as the amount of subcooling in the inlet water.

Based on the above, the staff concluded that the FOAM code predicted accurately the swollen levels measured in the three tests. These tests were within the range of power levels, pressures and geometric configurations which would exist during the CFT line break accident. The staff concluded that the use of the FOAM code is appropriate in calculating two-phase mixture heights for this accident.

The results of the application of B&W's FOAM code to the CFT line break accident were presented above. The core was predicted to be covered with two-phase mixture during the accident except for the period between 500 and 700 seconds after the accident. The peak cladding temperature occurred at approximately 700 seconds and reached 1199°F.

In examining the swollen levels predicted by FOAM for this accident, it was necessary to point out a conservatism which may have an exaggerated effect if compared to a more realistic calculation. The lowest liquid levels predicted by CRAFT were used as input to the FOAM code. This is actually a contradiction to fact, since the lowest liquid level that CRAFT predicted has a high swollen level (above the top of the core). This swollen level (above the top of the core) did not allow any significant cladding heat up. On the other hand, for the lower swollen level consistent with the FOAM prediction, CRAFT predicted more liquid left in the vessel and resulted in about four more feet of liquid level in the core (9 feet versus 5 feet). This calculation predicted the core to be covered with two-phase mixture and there also was no significant cladding heat up. Therefore, for a consistent set of predictions (high swollen level and low liquid level or a low swollen level and high liquid level) there was no significant cladding heat up. The analysis which was reported was the worst combination of both situations and resulted in an increase in cladding temperature.

To independently determine the two-phase mixture height in the core, the staff and its consultant, Aerojet Nuclear Corporation, developed a code (SWELL) using the Wilson bubble-rise model and a calculational procedure developed by GE and described in the Quad-Cities application (Docket 50-254 and 265). The SWELL code used essentially the same calculational scheme as B&W's FOAM code. Preliminary calculations using this code also showed agreement with results obtained using B&W's FOAM code for the Westinghouse tests.

Since the SWELL code was not well indexed against experimental tests, the staff also examined the cladding heat up transient in the 500 to 700 second period where B&W predicted the core was uncovered. Using the TOODEE (Reference 5) heat transfer code, the sensitivity of the peak cladding temperature to swollen level was examined. The swollen level was reduced by 25% which resulted in an increase in peak cladding temperature to 1552°F at 700 seconds. Although the temperature did increase 300°F the resultant peak cladding temperature was acceptable.

Conclusions

Based on the staff independent calculations and the applicant's analysis, the staff concluded that the emergency core cooling system, as modified, provides adequate protection for a break of a CFT line and that the acceptance criteria, as described in the Commission's Interim Policy Statement, were met:

1. The maximum calculated fuel element cladding temperature does not exceed 2300°F.
2. The amount of fuel element cladding that reacts chemically with water or steam does not exceed 1% of the total amount of cladding in the reactor.

3. The calculated clad temperature transient is terminated at a time when the core geometry is still amenable to cooling, and before the cladding is so embrittled as to fail during or after quenching.
4. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long lived radioactivity remaining in the core.

The results of the applicant's analyses for a loss-of-coolant accident initiated at a core power level of 2568 MWt showed that the acceptance criteria were met on the basis of analyses performed in accordance with an acceptable evaluation model given in the Interim Policy Statement.

Based on the evaluation of the applicant's analyses described above, the staff determined that the emergency core cooling system is acceptable and provides adequate protection for any LOCA.

7.1.4 Loss-of-Coolant Accident With Idle Reactor Coolant Pumps

General

The Oconee Units were designed to permit operation at partial power with one or two of the four reactor coolant pumps in an idle condition. The applicant supplied analyses of a LOCA for two of the conditions.

The Technical Specifications limit the power level for idle pump operation to approximately 75% and 50% of full power for three and two pump operation, respectively. The lower power level reduces the initial fuel temperatures and decay heat generation when compared to the full power-four pump case. This had the effect of reducing the peak cladding temperature calculated for such an accident. Due to the complexities of the hydrodynamics which occur during a LOCA, the effect of the lower initial core flow rate on peak cladding temperatures was not obvious. The purpose of the applicant's analyses was to determine the combined effects of both the thermal (primarily lower power) and hydraulic (primarily lower flow) changes on ECCS performance during a LOCA with idle pumps.

Applicant's Calculations

The applicant analyzed two cases to determine the effect of idle pumps on ECCS performance. The specific break analyzed in each case was a 8.55 ft^2 split in a cold leg (the limiting case for a LOCA from 102% power). Each case was with two pumps operating with a power level of 55% of full power, the Technical Specifications limit for two pump operation. A break in one of the operating cold legs resulted in a peak cladding temperature of 1265°F. For the second case, a break in an idle cold leg was analyzed and resulted in a peak cladding temperature of 1305°F. The methods specified in BAW-10034 (the B&W ECCS evaluation model) were used in these calculations. The results of both these LOCA's are well within the criteria set forth in the Commission's Interim Policy Statement.

Conclusions

Although the applicant did not analyze a complete spectrum of break sizes and locations for all idle pump operating conditions, the staff concluded that those analyses presented indicated a LOCA from operation with idle pumps is less severe than those previously considered for four pump operation.

7.1.5 Net Positive Suction Head

The staff requested that the applicant provide the results of analysis in the FSAR to justify that the ECCS pumps have adequate net positive suction head (NPSH) under LOCA conditions.

For this analysis, the applicant used the Oconee "as built" configuration, sizes, layouts, etc., and made assumptions based on both credit for reactor building pressure and no credit for reactor building pressure (saturation pressure of sump water). The applicant also assumed that the reactor building spray pump would be throttled back from 1,500 gpm to 1,000 gpm during the ECCS recirculation mode. In all cases for the low pressure injection pumps, the available NPSH exceeded the required NPSH for the worst case assumptions of maximum sump temperature and no credit for building pressure.

Since a complete loss of containment over-pressure for this dry containment concept is not likely (major failure of leak tight reactor building barrier) and an overpressure of 5.26 psi will provide adequate

NPSH at the maximum expected sump temperature of 227.7°F, the staff concluded that the design is acceptable.

7.1.6 Failure Detection

The applicant was requested to provide additional information on how failures in the engineered safety features will be detected during normal operation. The applicant stated in Supplement 11 to the FSAR that failures in the engineered safety features will be detected during normal plant operation by online periodic testing and inspection, comparison of parameter readings, and by automatic annunciation whenever continually monitored critical parameters exceed allowable values. Operational tests of the low and high pressure injection systems will be augmented by the fact that these systems are used to perform normal as well as emergency functions. Equipment used for emergency functions only, such as reactor building spray system and the reactor building penetration room ventilation system have been designed to permit periodic tests. The penetration room ventilation system may be actuated during normal operation for testing. The method and frequency of testing these systems are included in the Technical Specifications. The staff concluded that there is reasonable assurance that failures in these redundant systems will not go undetected for a significant length of time during normal operation.

7.1.7 Field Run Piping

The staff requested that the applicant provide information in the FSAR which identifies field run piping and state the practice employed for routing and exercising engineering control over all such piping.

The applicant stated that all main run process piping was detailed on engineering drawings. Items such as vents, drains, valve bypass warming lines and pump seal water for all systems were field run. All instrument impulse lines, except the reactor coolant flow impulse line which were detailed-routed, were field run after endpoints and specific routing requirements were defined by engineering. The staff concluded that the method of routing and engineering control of field run piping is acceptable.

7.1.8 Non-Class I Equipment Failure

By letter of September 26, 1972 the applicant was requested to review the Oconee Nuclear Station, Units 1, 2 and 3 to determine whether the failure of any non-Class I (seismic) equipment could result in a condition, such as flooding or the release of chemicals, that might potentially adversely affect the performance of safety-related equipment required for safe shutdown of the facility or to limit the consequences of an accident. The applicant responded by letter on October 24, 1972 and by FSAR Supplement No. 13, Amendment No. 39 to the application for an operating license.

The applicant stated that a remote possibility of flooding in the turbine building at the basement level due to failure of expansion joints in the condenser cooling water system near the condenser water box inlet or outlet nozzle does exist. The applicant's analysis showed that a worst leak condition would result in a flow rate of 235 cubic feet per second into the turbine building basement area. The volume of the turbine building is 160,000 cubic feet per foot of depth and, therefore, the flooding rate is about 0.088 feet per minute until the elevation of the break is reached, assuming all water would be contained in the turbine building. The applicant committed to providing 1.5 foot high curbs at all entrances to the auxiliary building from the turbine building prior to Oconee Unit 1 operation to permit 17 minutes of water storage in the turbine building basement. Turbine building sump level alarms will alert the control room operator to a flooding condition and corrective action can be taken by isolating the appropriate half of the condenser shell well within the 17 minute time period.

The applicant also stated that the auxiliary building could be subject to flooding from the fire protection system and the ventilation cooling water system. The fire protection system header inside the auxiliary building is not energized normally but is manually energized to fight a fire. The ventilation cooling water system contains flow limiting valves installed in all supply lines entering the auxiliary building larger than 3 inches in diameter. The maximum flooding flow rate is 1140 gpm. According to the applicant 10 minutes is available for corrective action before safety-related equipment would be affected, even if it is assumed that auxiliary building sump pumps are not operating. Again, high level alarm sensors in the auxiliary building sumps will warn the control room operator to take corrective action.

The staff concluded that the plant design and the corrective action taken by the applicant are acceptable with respect to the failure of non-Category I equipment.

7.1.9 Auxiliary Service Water

The applicant stated that the water statically trapped in the condenser cooling water intake and discharge lines below elevation 791.0 MSL has a volume of 8,825,000 gallons and is adequate to supply the three Oconee Units with steam generator boil off for safe shutdown for a period of 37 days in the extremely unlikely event that all water in the condenser intake canal is lost. Although complete loss of the intake canal water is a very remote possibility since the intake structure and dike are Class I (seismic) design and a flood which would fail the intake canal dike is unlikely (see Section 3.3), the applicant was asked to describe the auxiliary service water system (and its design basis) which is utilized to pump the stored water to the steam generators. The applicant responded to this request by letter on November 20, 1972 and revised the FSAR by Amendment 39.

The auxiliary service water system consists of a 3000 gpm, 176 foot head pump which takes its suction from the Unit 2 intake conduit and discharges by separate lines into the auxiliary feedwater header for each steam generator. The intake conduits for all three units are interconnected by crossover and rewatering lines. Electrical power for the pump is taken from the plants 4160 volt standby Bus No. 1. All valves in the system are either check valves or manually operated valves. The system was designed for decay heat removal following the loss of all main and auxiliary feedwater systems and the decay heat removal system. The staff concluded that the system provides adequate backup protection against the improbable total loss of the main condenser intake canal.

7.1.10 Anticipated Transients Without Scram

In connection with the review of potential common mode failures the staff considered the need for means of preventing common mode failures from negating scram action and the possible need for design features to make tolerable the consequences of failure to scram during anticipated transients. This concern is applicable to all light water cooled power reactors.

This problem is being studied on a generic basis and requires further review by the staff. If the probability of any of the events considered is determined to be sufficiently high to warrant consideration as a design basis for plants such as Oconee Units 2 and 3, suitable design modifications to reduce the probabilities or to limit the consequences to acceptable levels may be necessary.

7.1.11 High-energy Line Rupture External to the Reactor Building

In December 1972, the applicant was asked by the staff to assess the consequences of postulated pipe failures outside of the reactor building structure, including failure of the main steam and feedwater lines. The applicant has completed its assessment for Oconee Units 2 and 3 utilizing criteria and guidelines provided by the staff (See Appendix E to this Supplement). The basic criteria require that:

1. Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from all effects resulting from ruptures in pipes carrying high-energy fluid, up to and including a double-ended rupture of such pipes, where the temperature and pressure conditions of the fluid exceed 200°F and 275 psig. Breaks should be assumed to occur in those locations specified in the "pipe whip criteria." The rupture effects on equipment to be considered include pipe whip, structural (including the effects of jet impingement) and environmental.
2. Protection be provided for equipment necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, from the environmental and structural effects (including the effects of jet impingement) resulting from a

single open crack at the most adverse location in pipes carrying high-energy fluid routed in the vicinity of this equipment, where the temperature and pressure conditions of the fluid exceed 200°F and 275 psig. The size of the cracks should be assumed to be 1/2 the pipe diameter in length and 1/2 the wall thickness in width.

The applicant provided the staff with an initial report of its assessment by letter dated April 25, 1973. The report was identified as Report No. OS-73.2 and entitled "Analyses of Effects Resulting From Postulated Piping Breaks Outside Containment for Oconee Nuclear Station, Units 1, 2 and 3." The applicant, by letter dated June 22, 1973, submitted Supplement 1 to Report No. OS-73.2 in order to provide additional information identified to the applicant by the staff as necessary for the completion of the staff's evaluation of this matter for the Oconee Units. The applicant will incorporate Report No. OS-73.2 and Supplement 1, by reference, into the Oconee license application.

<u>Routing of High-Energy Lines Outside Containment and the Relationship to Safe Shutdown Systems</u>

The assessment of the high-energy line failure problem includes the consideration of all high-energy lines; however, experience to date indicates that the major concerns and required modifications are associated with the main steam and feedwater lines and major branch lines appended to them. A brief description of the routing of these lines is presented below. Since Units 2 and 3 are identical, a single description is given, but this description is applicable to both units.

The reactor building contains two steam generators each having its own main steam line and main feedwater line. One main steam line leaves the reactor building and is routed outside of all structures to the turbine building. The other main steam line leaves the reactor building and is routed through the penetration room for about 20 feet and then outside of all structures to the turbine building. Both main feedwater lines are routed from the turbine building, through the penetration room to the reactor building. Therefore, the penetration room enclosure houses a portion of one main steam line and two main feedwater lines. The turbine building houses a portion of both main steam lines and both main feedwater lines. The only other high energy piping passing through the penetration room to the reactor building of any significance is that which is associated with the primary system feed and bleed and pump seal system. The reactor coolant letdown is cooled before leaving the reactor building so this system is essentially a high pressure system rather than a high pressure and high temperature system.

All electrical and fluid systems required for safe plant shutdown communicate with the reactor building by routing through the penetration room enclosure. The penetration room is a near tight enclosure capable of slight negative pressure to assure that penetration leakage from the reactor building is filtered before release to the external environment. However, there are potential paths for communication between the penetration room, the auxiliary building and control room if a serious overpressurization of the penetration room should occur. The turbine building and auxiliary building (including the control room) contain electrical and fluid systems required for safe plant shutdown.

Results of Assessment

The applicant states in Report No. OS-73.2 that all high energy piping system designs were in accordance with established criteria including the AEC General Design Criteria and that all piping systems were classified in accordance with the criteria established. These criteria and classifications are contained in the FSAR as part of the Oconee application for operating licenses. Furthermore, the report stated that all high energy systems were designed to preclude pipe rupture based on conservative engineering practices.

In Report No. OS-73.2 the applicant compared maximum thermal stresses in the main steam line and main feedwater line during normal operation with the ANSI B31.1.0 (1967) Code allowable stress values and reported them to be 4% and 16% of allowable, respectively at the containment terminal points where line ruptures are required to be postulated. Likewise, normal operating pressures for the main steam line and main feedwater line were reported to be 20% and 29%, respectively, of actual code pressure capability. In accordance with the staff guidelines the applicant prepared a stress analysis summary and showed that in all cases the maximum combination of stresses are less than the allowables established by the staff. The applicant further stated that safety-related portions of the main steam and main feedwater lines were properly classified to assure high quality in procurement, fabrication, test and erection.

Report No. OS-73.2 also states that the applicant has reviewed and analyzed all high energy mechanical piping systems outside the reactor building in accordance with the staff definition of high energy lines and postulated breaks in accordance with the staff guidance for systems which are normally in operation and systems which are not normally in operation. It also states that reactor building integrity with respect to postulated breaks is assured because the mechanical penetrations and the reactor building were designed for pipe break loads. The applicant postulated double ended breaks and equivalent area longitudinal breaks at terminal ends, butt weld joints of ells, tees, laterals, etc., and nozzle weld joints; and critical cracks of area equal to the product of 1/2 the pipe diameter and 1/2 the wall thickness at any location along straight and curved sections of piping. Piping larger than 1 inch nominal pipe size was reviewed for the consequences of a double ended break; larger than 4 inches for the consequences of double ended and equivalent area longitudinal breaks; and larger than 1 inch for the consequences of critical cracks.

Report No. OS-73.2 summarizes the applicant's review of the consequences of postulated high energy line breaks with regard to environmental effects and physical damage to the station on a case-by-case basis. Contained in this summary are the operational analyses which describe the sequence of events following a piping break including the resultant reactor and primary system transients. The cases considered are listed in OS-73.2 with engineering data, consequences, environmental effects, station situation, remedial action and required station modifications (if any).

On the basis of its assessment the applicant concluded that the following modifications are required to meet the staff criteria for safe shutdown following a postulated break in a high-energy pipe external to the containment.

1. Install lightweight blowout panels in the penetration room to relieve overpressure from a steam line or feedwater line break.
2. Reinforce the battery room wall adjacent to the penetration room to protect the station batteries from overpressure and jet impingement.
3. Shield the low pressure injection line and electrical cables in the penetration room from steam line jet impingement.
4. Install emergency feedwater bypass lines around postulated pipe break areas for both steam generators.

5. Install main feedwater line restraints between the reactor building anchor and isolation check valves.
6. Install interconnection between the units of the feedwater bypass line described in d. above.

The applicant has stated that all required modifications will be completed on Unit 3 prior to startup. For Unit 2, the major modifications are to be completed as soon as practicable, but because of the realities associated with the procurement of materials the completion of installation of certain modifications will occur after scheduled startup of the plant. All the modifications for Unit 2 are scheduled to be completed by mid-December of this year, all but one are scheduled to be completed by November 1, 1973. It is expected that Unit 2 may be ready to operate at appreciable power levels in September or October. The applicant proposes to establish special interim measures and to conduct a special inservice-inspection program of critical areas until the modifications are completed.

Staff Evaluation and Conclusion

The staff has evaluated the assessment performed by the applicant and has concluded that the applicant has analyzed the facilities in a manner consistent with the intent of the criteria and guidelines provided by the staff. The staff agrees with the applicant's selection of pipe failure locations and concludes that all required accident situations have been addressed appropriately by the applicant.

Furthermore the staff has evaluated the analytical methods and assumptions used in the applicant's analyses and find them acceptable and concurs with the proposed plant modifications and the criteria to be used in their designs.

The staff is convinced that the applicant has made every reasonable effort to expedite the completion of the required modifications for Unit 2 and has concluded that operation of Unit 2 for the relatively short period of time involved until completion of the modifications is acceptable in vie of the interim inservice inspection measures that will be followed during this time period.

7.2 Containment Spray and Cooling System

The staff requested that the applicant provide analysis in the FSAR to justify that the containment spray pumps have adequate net positive suction head. This analysis was performed with the analysis for the ECCS pumps described in Section 7.1.5 and the results were the same. The staff concluded that the design is acceptable.

7.3 Post-Accident Hydrogen Control

Using Regulatory Guide 1.4, Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors, and Regulatory Guide 1.7, Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident, the staff made a new independent analysis of the incremental doses at the site boundary resulting from the purging of hydrogen from the reactor building following a LOCA. This analysis showed that for

30 days of purging after 460 hours holdup (required to limit hydrogen to 4% by volume), the I-131 dose would be 150 rem and the Xe-133 + Kr-85 whole body dose would be 0.80 rem. At the LPZ distance the doses would be 9.5 rem to the thyroid and 0.05 rem to the whole body. The data input to the hydrogen purge dose model is shown in Table 7.5.

The purge dose plus the LOCA dose at the LPZ, 118 rem to the thyroid and 1.6 rem to the whole body, would be less than 10 CFR Part 100 doses. Therefore, the staff has concluded that the applicant's provisions for post-accident hydrogen control are acceptable.

TABLE 7-5

DATA INPUT FOR HYDROGEN PURGE DOSE MODEL

Power Level	2568 MWt
Building Volume	1.9×10^6 ft^3
Type of Purge	Continuous
Holdup Time	460 Hours (19.2 Days)
Duration of Purge	30 Days
Filter Reduction	10
χ/Q at Site Boundary	5.2×10^{-6}
χ/Q at LPZ	3.3×10^{-7}

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9. H. Ogasawara, et al - Cooling Mechanism of the Low Pressure Coolant Injection System of Boiling Water Reactors and Other Studies on the Loss-of-Coolant Accident Phenomena, presented at the 1973 ANS Meeting (Salt Lake City).

8.0 INSTRUMENTATION, CONTROL AND POWER SYSTEM

The staff review of the Oconee instrumentation, control and power system on pages 49-54 of the Oconee Unit 1 SER is applicable to Units 2 and 3. Additional matters related to the Units 2 and 3 review are discussed below.

8.1 Reactor Protection and Control System

By letter of March 7, 1973, the staff requested that the applicant perform a review of all control circuits and safety-related equipment to assure that disabling of one component does not, through incorporation in other interlocking or sequencing controls, render other components inoperable. The applicant responded to this request by letter on May 3, 1973 and stated that the review determined that the disabling of one component does not render other redundant components inoperable. The applicant further stated that all modes of test, operation and failure were considered in the analyses. Systems considered were the Reactor Protective System, Nuclear Instrumentation, Engineered Safety Features Protection System, Control Rod Drive System, Emergency Power Systems and Emergency Power Switching Logic Systems.

The applicant's review included station procedures to ensure that whenever a safety-related system or component is removed from service, the redundant system or component is functionally tested before or immediately after the system or component is removed from service. The applicant found the procedures to be adequate in this respect.

The staff concluded that the applicant's actions on this matter are adequate to assure that disabling of one safety related component or system will not disable its redundant component or system.

Careful consideration was given to the periodic testing of the reactor protection and control system required to assure reliable and redundant reactor trip action, and these considerations were factored into the Technical Specifications. For example, new requirements for performing discharge tests on the stations' batteries and for testing the 125 VDC system isolation diodes and their monitors were established.

8.2 Initiation and Control of Engineered Safety Features

In addition to the review discussed in 8.1 above which included the engineered safety features, the applicant committed to performing periodic discharge tests on the batteries in the 125 VDC switchyard and Keowee systems and to perform periodic checks on the control circuitry for the 230 kV switchyard. Because a portion of the 230 kV switchyard is part of the distribution system for the onsite power system (Keowee hydro units), the batteries of the 125 VDC switching station power system have the same test requirements as the Keowee batteries and meet the applicable failure criteria.

8.3 Offsite Power

In addition to the four 230 KV transmission lines connected to the 230 KV station switchyard, two lines will be added prior to operation of Unit 3. The 500 KV switchyard will be connected to the 230 KV switchyard through an autotransformer prior to operation of Unit 3.

The Technical Specifications require that redundant 230 kV transmission lines will not be on the same transmission towers (although they may be on towers on the same corridor) to minimize common mode failure of off-site power.

8.4 Onsite Power

That portion of the 125 VDC Instrumentation and Control Power System for Unit 3 which is shared with Unit 2 will be available prior to operation of Unit 2.

8.5 Cable and Equipment Separation and Fire Prevention

8.5.1 Cable Separation

The applicant has supplemented his cable installation criteria. Cable trays in Units 2 and 3 will not be filled above the tray side rails; additional cable trays were installed to assure compliance with this commitment. The staff concluded that the provisions for separation of cables are acceptable.

8.5.2 Fire Prevention

A localized fire in the control rod drive system transfer panel for Unit 1 was caused by a loose or high resistance connection to a rod group patch connector. To preclude the recurrence of this type of incident the applicant has replaced the bus clip type of connectors originally used with circular, MS type, panel mounted, multipin connectors. The staff concluded that this connector modification which has been incorporated on Units 2 and 3 is a significant improvement and is acceptable.

9.0 CONTROL OF RADIOACTIVE EFFLUENTS

The staff evaluation of the applicant's radiation protection measures is contained on pages 55-58 of the Oconee Unit 1 SER. The earlier evaluation of radioactive waste management was supplemented as discussed below.

The applicant was requested to provide additional information to show that the unit vent radiation monitor system will have the required sensitivity for measuring the anticipated levels either for a continuous or instantaneous release and to discuss iodine plate out. The applicant was also requested to verify that the charcoal to be used in the radiation monitors for iodine is impregnated to assure the collection of both elemental and non-elemental forms of iodine and to provide information as to the frequency at which the charcoal will be changed and tested.

In addition, the Technical Specifications were revised to meet the intent of "low as practicable" with regard to full utilization of waste processing equipment and were revised to meet the intent of Regulatory Guide 1.21, Measuring and Reporting of Effluents from Nuclear Power Plants and to specify the reporting of all planned and unplanned releases of radioactivity.

On the basis of its review of the information submitted, the staff concluded that the proposed radwaste systems for reduction of radioactive material in effluents and radiation monitoring systems satisfy the requirements of 10 CFR Part 50.34a of the Commission's Rules and Regulations for keeping levels of radioactive material in effluents to unrestricted areas as low as practicable.

9.1 Effluent Treatment Systems

The waste treatment systems were designed to provide for controlled handling and disposal of radioactive liquid, gaseous and solid wastes. The applicant's design objective for the radwaste systems was to release amounts which are within the limits set forth in 10 CFR Part 20. In addition, the applicant agreed to maintain and use existing plant equipment to achieve the lowest practical radioactive releases to the environment in accordance with the requirements of 10 CFR Part 50.

The liquid waste treatment system was sized to accommodate the waste produced during simultaneous operation of Units 1, 2 and 3 and is common to all three units. Table 9-1 gives component data for the liquid waste treatment systems. Units 1 and 2 share a common waste gas treatment system. Unit 3 has a separate waste gas treatment system which is interconnected to the system for Unit 1 and 2; however, these systems normally are operated independently.

The waste gas treatment system is capable of containing fission product gases stripped from the reactor coolant to permit decay of short-lived radioactivity before release to the environment.

The solid waste system packages waste in accordance with the regulations set forth in 10 CFR Parts 70-71 and conforms to the Department of Transportation shipping regulations.

9.1.1 Liquid Waste

System Description

The liquid radioactive waste system, common to Units 1, 2 and 3 consists of collection tanks, piping, pumps, evaporators, demineralizers, process equipment and instrumentation necessary to collect, process, monitor, store and dispose of potentially radioactive liquid wastes. The system is divided into two main parts; (1) the reactor coolant treatment system (RCTS) which includes the chemical and volume control system (CVCS) and (2) the liquid waste treatment system (LWTS). Treatment of the waste is dependent on the source, activity and composition of the particular liquid waste and on the intended disposal procedure. Cross connections between the subsystems provide flexibility for processing by alternate methods. More than half of the estimated maximum total radioactivity is collected in the LWTS and the rest from the RCTS.

Treated wastes are handled on a batch basis as required to permit optimum control and release of radioactive waste. Prior to release of any treated liquid wastes, samples are analyzed to determine the type and amount of radioactivity in a batch. Based on the results of an analysis, these wastes either are released under controlled conditions to the tailrace of the Keowee Hydroelectric Station or are retained for additional decay or further processing. Radiation monitoring equipment automatically terminates liquid waste discharges if radiation levels are above a predetermined level in the discharge line.

Reactor Coolant Treatment System (RCTS)

The reactor coolant treatment system, which includes the CVCS, processes the coolant letdown stream and other chemically clean sources such as equipment leakages from valve, flange and pump seal leakoffs within the reactor coolant system. Each unit has separate coolant bleed holdup tanks but shares a common coolant treatment system. The RCTS processes the liquid of highest activity in three different ways. Ordinarily part of the liquid is circulated through demineralizers to remove corrosion and fission products. After purification, part of the liquid is bled from the system and fed to the reactor coolant bleed evaporator (10 gpm) in order to remove the boric acid from the system. As neutron-absorbing fission products buildup in the fuel and as the fuel is depleted, it is necessary to continuously reduce the boron concentration. Reduction in boron concentration is accomplished primarily in the reactor coolant bleed evaporator. Most of the recovered boric acid is stored for reuse in the system. The condensate from the evaporator is collected in the condensate test tanks from which it can be discharged to the tailrace or used as makeup water for the reactor. If necessary, the condensate can be processed through a mixed bed demineralizer or recycled through the evaporator to further reduce its activity. In the later stages of a core life time, further removal of boron is accomplished by the deborating demineralizers.

The staff estimated that approximately 330,000 gallons from each Unit will be processed annually by the reactor coolant bleed evaporator resulting in an estimated release of 0.6 curies per unit of radioactivity (excluding tritium). This estimate of the anticipated annual release was based on the assumption that all of the reactor coolant bleed will be released each year after processing. Holdup and decay for a 30-day period was assumed prior to release. The applicant calculated a concentration level of 0.026 MPC for the discharge from one unit into unrestricted areas. Holdup volumes for both processed and unprocessed bleed are adequate. The staff concluded that the reactor coolant treatment system is capable of providing effluents which are considered as low as practicable in accordance with 10 CFR Part 50.

Liquid Waste Treatment System (LWTS)

The liquid waste treatment system collects and treats all chemically impure wastes that can not be released untreated. It is expected that more than half the estimated maximum total radioactivity will be collected in three different types of collection tanks (miscellaneous waste, high-activity waste and low-activity waste). Principal sources are floor and equipment drains, some leakoffs, and wastes from chemical laboratory drains, decontamination area drains, laundry wastes and demineralizer regenerants.

Liquid wastes expected to have a low-level of radioactivity are collected in the low-activity waste tank. Auxiliary building floor drains, laundry and shower wastes are expected to make up the major fraction of these wastes. After sampling and analysis, these wastes either are discharged directly to the tailrace of the Keowee Hydroelectric Station or are transferred to the miscellaneous waste holdup tanks and are processed through the waste evaporator (10 gpm). In the staff evaluation, it was assumed that all low-level waste is processed through the waste evaporator before release to the environment. The staff estimated that 50,000 gallons per year per unit is processed annually.

Liquid wastes expected to have an intermediate level of radioactivity are collected in the high-activity waste tank. Principal sources are the decontamination wastes, demineralizer regenerants, waste gas system and spent fuel systems drains. Based on the activity level of these wastes they are either transferred to the low-activity waste tank for release to the tailrace or are transferred to the waste evaporator for processing. Normal processing is through the waste evaporator.

The staff estimated that approximately 30,000 gallons per year from Unit 2 will be handled by this system, and a similar amount from Unit 3.

Liquid waste expected to have a high-level of radioactivity is collected in the miscellaneous waste holdup tank. Principal sources are the recycled wastes from the condensate test tanks, reactor building sump, sample sinks and leakoffs from the reactor vessel and coolant bleed tanks. This waste either is transferred to the low-activity waste tank for discharge or is processed through the waste evaporator. The staff assumed that all this waste is processed through the evaporator and estimated that approximately 100,000 gallons per year, per unit is handled by this system.

Condensate from the waste evaporator is collected in the condensate test tanks, sampled and analyzed, and either reused in the plant or released. The bottoms from the evaporator which contain the concentrated impurities is transferred to the solid waste drumming facility and packaged as solid waste.

Oconee, Units 2 & 3, like Unit 1, have once through steam generators, hence there is no secondary blowdown. Instead, reliance is placed on "full flow" Powdex polishing demineralizers upstream of the feedwater train. These demineralizers are capable of treating 70% of the feedwater flow at full power.

The applicant analyzed the effect of a leak from the feedwater system into the turbine room sump. This leakage normally is discharged into Lake Keowee via the cooling condenser discharge. If significant activity occurs in this liquid, provisions are made for routing it into the radioactive waste treatment system for treatment prior to release or reuse. The staff estimated that the untreated annual releases from this source are not expected to be a contributing source of activity.

Estimated releases of radioactivity from the LWTS by the applicant were determined on the basis of each unit operating with defective fuel and assumed that all liquid collected was reactor coolant containing the design fission product activity. It further was assumed that collection took place over a period of 60 days at a rate of 435 gallons/day and included an additional holdup of 30 days for decay prior to discharge. The resulting station effluent concentration averaged over 60 days was estimated by the applicant to be 0.16 of the MPC for unrestricted areas.

The staff estimated an annual release of 1.1 curies of radioactivity (excluding tritium) from each unit. This estimate assumed that all waste collected in the LWTS are processed through the waste evaporator prior to discharge and considered each unit operating with 0.25% of the operating power equilibrium fission product source term. Based on present operating experience at other operating plants, the staff estimated 1000 curies per year of tritium is released from each unit.

The staff concluded that the LWTS has sufficient capacity to permit flexibility in station operation and the means of providing effluents considered "as low as practicable".

Radioactive liquid waste released from the station is from either the low-activity waste tank or the condensate test tank. In order to achieve the highest dilution ratio, the applicant committed where possible to coordinate releases with the operation of the Keowee Hydroelectric Station. Assuming that the waste is diluted by the annual average flow of 1100 cfs, then the average activity of the discharge could be 3×10^{-9} μCi/cc. Estimates of doses to individuals from liquid effluents at Clemson and Pendleton, where drinking water is withdrawn from the Keowee River, were 0.64 mrem to the thyroid and 0.54 mrem to the whole body. These dose estimates indicated that releases of radioactive effluents from normal operation of the station are conducted well within the limits of 10 CFR Part 20 and are considered as low as practicable in accordance with 10 CFR Part 50. The staff concluded that the design criteria of the liquid radwaste system were acceptable.

9.1.2 Gaseous Waste

System Description

The waste gas treatment system (WGTS) consists of gas decay tanks, piping, high-efficiency particulate filters, charcoal adsorbers and instrumentation necessary to collect, store, process, monitor and dispose of potentially radioactive gaseous wastes. The purpose of the WGTS is to maintain an inert cover gas of nitrogen in tanks and equipment that contain potentially radioactive gas, holdup radioactive gas for decay and to release gases (radioactive and non-radioactive) to the atmosphere under controlled conditions. Units 1 and 2 share a common waste gas treatment system. Unit 3 has a separate waste gas treatment system which can be interconnected to the system for Unit 1 and 2; however, these systems normally are operated independently.

The major source of gaseous waste activity during normal operation is the waste gases, primarily hydrogen, nitrogen, fission-product gases (kryptons and xenons) and halogens (mostly iodines) removed from the reactor coolant letdown into the various holding tanks. This is principally from the chemical and volume control system (CVCS), the reactor coolant bleed evaporator and reactor coolant drain tanks. Additional sources of gaseous waste activity which are not concentrated enough to permit collection and storage include the ventilation air released from the auxiliary buildings, turbine buildings, exhaust from the condenser air ejectors, and air purged from the reactor buildings.

The gaseous radioactivity received by the waste gas treatment system (mostly hydrogen with small amounts of entrained noble fission gases) enters a circulating nitrogen stream. These gases are collected in a vent header and compressed by one of two compressors to one of two gas decay tanks having a design capacity of 1,100

Table 9-1

Waste Treatment System Component Data

	Number	Capacity
Low Activity Waste Tank	2	3,000 gal (ea)
High Activity Waste Tank	2	1,950 gal (ea)
Waste Holdup Tank	2	20,250 gal (ea)
Waste Evaporator Feed Tank	1	3,000 gal
Waste Evaporator	1	10 gpm
Coolant Bleed Evaporator	1	10 gpm
Coolant Bleed Holdup Tanks	2	82,500 gal (ea)

cubic feet at a pressure of 100 psig. The decay tank functions both as a surge and storage tank. As liquid storage tanks are filled, the excess gas is stored in the waste gas decay tank. Likewise, as liquid storage tanks are emptied, gas flows from the decay tank back into the vent header. When the required operating pressure is reached, the contents of the tank are sampled and analyzed to determine the permissible release rate or the need for holdup for radioactive decay. The contents of the decay tank is discharged through the unit vent (200 ft. above ground level). Monitoring of the gas discharge is provided by a radiation monitor, which on a high radiation signal, closes the valves through which the gas is being discharged.

The system also contains a waste gas exhauster used when large volumes of gas containing little or no radioactivity are released to the unit vent. The exhauster and its isolation valves are interlocked to trip the exhauster and close the valves in case of high radiation level in the line going to the unit vent. The exhauster normally does not operate and is valved off by a manual valve upstream of the exhauster.

The applicant estimated an average holdup time in the waste decay tanks of 49 days for all three units operating at full power. The staff calculated a holdup time of 30 days for both systems. Considering simultaneous operation of Units 1, 2 and 3, the applicant estimated the total average annual concentration at the exclusion area boundary to be 0.26 of the MPC for unrestricted areas released from the gas processing system. The staff analysis indicated that about 10,700 curies of noble gases are released annually from all three units from this source. The staff concluded that equipment capacities are adequate to accommodate and store radioactive gases as necessary to provide effluents which can be considered as low as practicable as required by 10 CFR Part 50.

Radioactive gases may be released inside the reactor containment building when components of the reactor coolant system are opened to the building atmosphere for operational reasons or when minor leaks occur in the reactor coolant system. Provisions were made to purge the containment atmosphere through prefilters, high-efficiency particulate filters and charcoal adsorbers to the atmosphere through the monitored unit vent.

The applicant estimated that the concentration at the exclusion area boundary from the venting of three reactor buildings once each 30 days gives an average yearly dose of 0.11 of the MPC. The staff estimated an annual release of 2900 curies of noble gases and 0.78 curies of iodine-131 from the venting of three reactor buildings. The staff analysis considered a need to purge the containment atmosphere 12 times per year and that all venting is through HEPA filters and charcoal adsorbers. The staff concluded that the purge system is capable of providing effluents which are considered as low as practicable.

Radioactive gases also may be released to the auxiliary building through leaks and open equipment. Units 1 and 2 share a common building. Unit 3 has a separate auxiliary building. To reduce the release of radioactive materials, the buildings are maintained at negative pressure with respect to the outside pressure. Ventilation air moves from areas of low potential towards areas of higher potential. Gases purged from the auxiliary building are continually monitored and released to the atmosphere, untreated through the unit vents. A common fuel storage area serves Units 1 and 2 and a separate area serves Unit 3. Ventilation air in these areas is exhausted untreated through the auxiliary building exhaust systems and discharged to the unit vents. The staff estimated an annual release of 490 curies per year per unit of noble gases and less than 0.01 curie per year per unit of iodine-131. The staff concluded that the design criteria for the system were acceptable.

The turbine buildings are ventilated by 12 roof-mounted exhaust fans. Ventilation air is pulled through outside air louvers and discharged without treatment through the roof exhaust fans. The staff does not expect this to be a contributing source of radioactivity.

Radioactive gases which may enter the secondary coolant loop through a leak in the steam generator tubes are removed from the steam system along with any air inleakage by the air ejectors and are discharged from the monitored systems to the individual unit vents. The applicant assumed a leakage of 1 gpm of reactor coolant in one unit continuously over a year and from this calculated the concentration at the exclusion area boundary to be 0.089 MPC. The staff estimated an annual release rate of 670 curies per year per unit of noble gases and less than 0.018 curie per year per unit of iodine-131 from this source.

The staff estimated a total annual release rate from the gaseous radwaste treatment system of 15,700 curies/year of noble gases, and 0.8 curies per year of iodine-131. These values included releases from Unit 1 since Unit 1 and 2 share a common waste gas processing system. Radiation doses to individuals at the site boundary from gaseous effluents from three reactor units at the Oconee Nuclear Station were estimated to be 1.2 mrem/year whole body and 1.2 mrem/year to the thyroid from direct radiation. These dose estimates indicated that the release of gaseous radioactive effluents from normal operation of the station are conducted well within the limits of 10 CFR Part 20 and are considered as low as practicable as required by 10 CFR Part 50.

9.1.3 Solid Wastes

The sources of solid radioactive waste are spent demineralizer resins, filter and strainer elements, evaporator concentrates, and miscellaneous items such as contaminated clothing, filters, rags, paper, gloves and shoe covers. The spent resins are slurried to the drumming facility from the spent resins storage tanks and collected in suitable containers. These containers are equipped with filters to retain the solids and the liquid portion is returned to the high-activity liquid waste tank. The evaporator concentrates either are stored and shipped as liquids or are mixed with vermiculite of concrete and shipped as solid waste. The applicant has not yet made a final decision regarding this matter. Miscellaneous solid wastes (clothing, rags, paper, etc.) are hydraulically compressed in 55-gallon steel drums. All solid radioactive waste are packaged and shipped offsite to a licensed burial ground in accordance with AEC and DOT regulations. The staff estimated that approximately 370 drums of spent resins, and evaporator bottoms at approximately 20 curies/drum and about 600 drums of dry and compacted waste at less than 5 Ci/drum are shipped annually from each unit. The applicant did not make any estimates of the amounts of solid radwaste that are generated by this plant.

Design and operation of the solid radwaste system do not involve any unusual safety problems not already previously considered on any other PWR application.

9.1.4 Design

The radioactive waste treatment systems are designed and fabricated in accordance with acceptable codes and standards. The entire radwaste system is located in Class I (seismic) structures. The staff concluded that the buildings, equipment and piping designs were acceptable.

9.2 Radiation Monitoring Devices

9.2.1 Process and Area Radiation Monitoring Systems

The process radiation monitoring system was designed to provide information on radioactive levels in certain systems, leakage from one system to another, and radioactive levels released to the environment. The monitoring includes containment or vent stack; waste processing building and service area; fuel handling building; auxiliary building exhaust for air particulate, halogen, and gas;ccondenser air ejector gas; component cooling liquid; and waste processing system liquid effluent.

The area radiation monitoring system was designed to provide information on radiation fields in various areas of the plant for personnel protection. Unit monitors were located in the control room, containment, radiochemistry laboratory, charging pump room, fuel handling building, sampling room in-core instrumentation area, and the drumming station.

These monitoring systems detect, indicate, annunciate and/or record the levels or fields of activity to verify compliance with 10 CFR 20 and keep radiation levels as low as practicable. The staff concluded that the plant is adequately provided with process and area monitoring equipment.

9.3 Effluent Releases

The Technical Specifications conform with the most recent staff guidelines regarding effluent releases to the environment. In addition the Technical Specifications meet the intent of Regulatory Guide 1.21, Measuring and Reporting of Effluents from Nuclear Power Plants.

10.0 AUXILIARY SYSTEMS

10.6 Spent Fuel Handling System

The Oconee Unit 1 SER presented potential radiological dose from the refueling accident using old assumptions for the retention of iodine in the pool water and meteorology which were applicable at that time. During the Oconee Units 2 and 3 review the staff reevaluated the radiological doses using new assumptions for the retention of iodine in the pool water and new meteorology data (see Section 11.3 of this report). As a consequence of this reevaluation, the staff concluded that iodine filters should be added to the spent fuel handling facility exhaust vents as soon as practical to reduce offsite doses resulting from the fuel handling accident to lower achievable levels.

11.0 ANALYSES OF RADIOLOGICAL CONSEQUENCES FROM DESIGN BASIS ACCIDENTS

11.1 General

New dose calculations for the Oconee 2/3 review were performed as the result of a revision in the site meteorological data. The revised meteorological diffusion factor (X/Q) at the site boundary was about a factor of two greater than the diffusion factor used in the earlier dose calculations. The accident cases investigated were the design basis loss-of-coolant accident and the fuel handling accident.

11.2 Loss-of-Coolant Accident

The LOCA dose calculations included credit for iodine removal by boric acid sprays, a refinement to the calculational technique which was not included in the original Oconee dose calculations. The sprays were assumed to affect the removal of the elemental and particulate fractions of the iodine in the reactor building. The spray removal rate for elemental iodine was calculated to be 1.1 hr^{-1} for the injection period and 0.7 hr^{-1} for the recirculation period. The effectiveness of the boric acid sprays for elemental iodine removal was assumed to terminate once the initial elemental iodine activity had been reduced by a factor of two. For the particulate iodine, the effectiveness of the sprays was assumed to terminate when the particulate activity had been reduced by a factor of 100. The reactor building spray system parameters employed to calculate the elemental spray removal rates are shown in Table 11-1.

Fifty percent of the leakage following a LOCA was assumed to go through the penetration room ventilation system filters which were considered to be 90% efficient for the removal of elemental and particulate iodine and 70% efficient for the removal of organic iodine. The assumption that 50% of the leakage was treated by the penetration room filters was consistent with the previous calculations and was addressed in the Oconee Technical Specifications.

With credit for penetration room filtration and spray removal, the LOCA 2-hour site exclusion boundary dose was calculated to be 235 rem to the thyroid and 5.5 rem to the whole body. The USAECAAR and TACT computer programs were used by the staff to calculate these doses. At the low population zone distance the 30 day dose was calculated to be 108 rem to the thyroid and 1.5 rem to the whole body. The 0-2 hour iodine dose reduction factor attributed to the filters alone was 1.8 and to the sprays alone was 1.6 for a total dose reduction factor of 2.9 for the filters and sprays. The assumptions included in the LOCA dose calculation are shown in Table 11-2.

11.3 Fuel Handling Accident

The fuel handling accident analysis assumed that all 208 rods in a fuel bundle were damaged and that the accident occurred 72 hours after shutdown of the reactor. The USAECAAR computer program which incorporates the source terms and release assumptions of Regulatory Guide 1.25. Assumptions used for evaluating the potential radiological consequences of a fuel handling accident in the fuel handling and storage facilities for boiling and pressurized water reactors was utilized to perform the dose calculations also. The 2-hour dose at the site exclusion boundary was calculated to be 56 rem to the thyroid (1.0 rem to the whole body) without filters in the spent fuel building ventilation system and 9.4 rem with filters. The staff concluded that filters should be provided even though the doses without the filters would be within 10 CFR Part 100 Guidelines.

11.4 Conclusion

The staff concluded that the offsite doses for the design basis accident and the fuel handling accident are less than the guideline values of 10 CFR Part 100. The staff further concluded that iodine filters should be provided in the spent fuel handling facility exhaust vents to further reduce doses resulting from a fuel handling accident. The staff has informed the applicant that the filters will be required to be installed before returning to normal operation after the first refueling of Unit 2.

TABLE 11-1

BORIC ACID SPRAY PARAMETERS FOR

REMOVAL OF ELEMENTAL IODINE

Injection Period	0 - 30 Min.
Recirculation Period (until effectiveness of spray terminates)	30 - 46 Min.
pH	4.5
Pump Flow Rate - Injection	1500 gpm
Pump Flow Rate - Recirculation	1000 gpm
Spray Height	82.5 ft.
Containment Volume	1.91×10^6 ft^3
Mean Drop Size	3800 Microns
Spray Removal Rate (λ_s)	
Injection Period	1.1 hr^{-1}
Recirculation Period	0.7 hr^{-1}

TABLE 11-2

LOCA DOSE ASSUMPTIONS

Power Level	2568 MWt
Source Release Fractions, Breathing Rates	Reg. Guide 1.4
Containment Leak Rate	
0 - 1 Day	0.25% Day^{-1}
1 - 30 Day	0.125% Day^{-1}
Meteorological Dilution Factors	
0 - 2 Hours Site Boundary (1609m)	2.2×10^{-4} sec/m^3
0 - 8 Hours LPZ (9650m)	2.35×10^{-5}
8 - 24 Hours	4.7×10^{-6}
24 - 96 Hours	1.5×10^{-6}
96 - 720 Hours	3.3×10^{-7}

12.0 CONDUCT OF OPERATIONS

The staff evaluation of conduct of operations in the Oconee Unit 1 SER (pages 70-75) is applicable to Units 2 and 3. Discussed below are those areas where the applicant has provided additional information in this area.

12.1 Technical Qualifications

The minimum qualifications for the key supervisory positions at the Oconee Nuclear Station will meet the requirements of the American National Standard, Selection and Training of Nuclear Power Plant Personnel, ANSI N18.1-1971. The applicant's operating organization is as stated on page 71 of the Oconee Unit 1 SER.

The staff concluded that the organization structure and the qualification of the staff for the Oconee Nuclear Station Units 1, 2. and 3 is adequate to provide continued engineering support and an operations staff capable of operating the proposed facility safely during normal and abnormal conditions, including initial startup of each Unit.

12.2 Operating Organization and Training

The training program for the Oconee staff Units 2 and 3 is identical to that provided for Unit 1 personnel. In addition, 5 candidates for Senior Reactor Operator Licenses and 5 candidates for Reactor Operator Licenses will be given 6 weeks training on the B & W simulator and 8 weeks of on-the-job training at the H. B. Robinson Nuclear Station. The staff concluded that the training program is acceptable.

Review and audit of station operations, maintenance and technical matters are performed by two committees, a Station Review Committee and a Nuclear Safety Review Committee.

The Nuclear Safety Review Committee is composed of a chairman, three members from the Steam Production Department (including the Oconee Station Superintendent or Assistant Superintendent) and two members from the Engineering Department, all appointed by the Executive Vice President and General Manager. The committee may be expanded to include outside consultants when necessary or desirable. It is the responsibility of this committee to review all procedures, procedure changes, design changes, and abnormal occurrences that may affect public health and safety. In accomplishing this task, the committee is charged with auditing station records, logs, reports, tests, minutes of the Station Review Committee meetings, and making written recommendations to the appropriate Vice President. Records of all meetings will be kept on file at the station. The applicant prepared a written charter for the committee.

The Station Review Committee is composed of the Assistant Superintendent (designated Chairman) the Operating-Engineer, Technical Support Engineer and at least two other station supervisory personnel. The committee meets monthly and at the call of Chairman and is charged with reviewing all new procedures and proposed procedure changes, proposed tests, proposed station design changes, and abnormal occurrences. The committee also reviews station operation for matters of potential safety significance. The Committee is charged with keeping minutes of all meetings and distributing a copy of these minutes to the Station Superintendent, the Assistant Vice President of Steam Production and to the Chairman of the Nuclear Safety Review Committee (discussed above). Findings of this Committee are forwarded to the Station Superintendent for appropriate action. The quorum, meeting frequency, responsibilities, and authorities of both committees are further delineated in the Technical Specifications. The staff concluded that the review and audit structure proposed by the applicant are acceptable.

12.3 Emergency Planning

Plant operations are performed in accordance with written and approved operating and emergency procedures. Areas covered include normal startup, operation and shutdown; abnormal conditions and emergencies; refueling; maintenance; periodic testing; and radiation control. All procedures, and changes thereto are reviewed by the Plant Operations Review Committee and approved by the Plant Superintendent prior to implementation.

The staff concluded that the provisions for preparation, review, approval, and use of written procedures are satisfactory.

12.4 Industrial Security

The plant site and its structures are protected by security fencing, lighting, surveillance and intrusion equipment, physical barriers, and a guard force. A system of personnel identification and access control to various areas within the plant site boundary was established. The applicant established administrative arrangements within its security program to effect liaison with law enforcement agencies in the event of a security emergency.

The staff reviewed the details of the applicant's Industrial Security Program and determined that it meets the regulatory requirements of AEC Regulatory Guide No. 1.17, Protection Against Industrial Sabotage. The staff concluded that the program is adequate and provides reasonable assurance that the risk associated with potential acts of sabotage that could lead to a significant threat to the public health and safety is acceptably low.

12.5 Test and Startup Program

The test and startup program implementation is the responsibility of the Duke Power Company. The program is conducted with the assistance of Babcock and Wilcox (B & W), and the Bechtel Corporation. A Test Working Group, consisting of personnel from the Oconee Nuclear Station (the Superintendent, Assistant Superintendent, the Station

Review Committee, and the Station Test Coordinator assigned to the test) and B & W, was established to coordinate activities during the preoperational test program. Assistance, as required is obtained from the Duke Engineering, Construction, Steam Production, and Electrical, Maintenance, and Construction Departments. A representative of the Oconee Nuclear Station is chairman of the Test Working Group.

The purpose of the test and startup program is to assure that the equipment and systems perform in accordance with design criteria, to effect initial fuel loading in a safe and efficient manner, to determine the nuclear parameters, and to bring the unit to rated capacity. The staff concluded that the test and startup program described by the applicant provides an adequate basis to confirm the safe operation of the station, and is acceptable.

12.6 QA Operations

In order for the staff to perform a periodic QA review, by letter dated March 27, 1973, the applicant was requested to provide the Oconee Quality Assurance Program for Operations in accordance with Section 50.34(b)(c)(ii) and Appendix B of 10 CFR 50 and to compare the plan with the guidelines presented in Regulatory Guide No. 1.33, Quality Assurance Program Requirements (Operations). The applicant responded by letter on April 27, 1973 and provided the staff with the Oconee Operational Quality Assurance Program.

The staff has concluded that the program is adequate but is still reviewing this program and will resolve any areas that require upgrading prior to operation of Oconee Unit 2.

13.0 TECHNICAL SPECIFICATIONS

The Technical Specifications in a license define certain features, characteristics, and conditions governing operation of a facility that cannot be changed without prior approval of the AEC. The staff reviewed the proposed Technical Specifications in detail and has held a number of meetings with the applicant to discuss their contents. Modifications to the proposed Technical Specifications submitted by the applicant were made to describe more clearly the allowed conditions for plant operation. The finally approved Technical Specifications will be made part of the operating license. Included are sections covering safety limits and limiting safety system settings, limiting conditions for operation, surveillance requirements, design features, and administrative controls. On the basis of its review, the staff concluded that normal plant operation within the limits of the Technical Specifications will not result in potential offsite exposures in excess of the 10 CFR Part 20 limits. Furthermore, the limiting conditions for operations and surveillance requirements will assure that necessary engineered safety features will be available in the event of malfunctions within the plant.

The Technical Specifications for Oconee Units 2 and 3 are revised versions of the Technical Specifications for Unit 1 which have been revised since the staff Oconee Unit 1 SER. Some of the significant changes were mentioned in the foregoing sections. There will be one set of Technical Specifications for all three units with applicable differences between the three units clearly designated in the document.

14.0 THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

The applications for operation of Oconee Units 2 and 3 are being reviewed by the ACRS. The staff intends to supplement this Safety Evaluation when the Committee's report to the Commission relative to its review is available. The supplement will append a copy of the Committee's report and will address the significant comments made by the Committee and any steps taken by the staff to resolve any unresolved issues raised as a result of the Committee's review.

15.0 COMMON DEFENSE AND SECURITY

The application reflects that the activities to be conducted will be within the jurisdiction of the United States and that all of the directors and principal officers of the applicant are United States citizens. The applicant is not owned, dominated, or controlled by an alien, a foreign corporation, or a foreign government. The activities to be conducted do not involve any restricted data, but the applicant agreed to safeguard any such data which might become involved in accordance with the requirements of 10 CFR Part 50. The applicant will rely upon obtaining fuel as it is needed from sources of supply available for civilian purposes, so that no diversion of special nuclear material for military purposes is involved. For these reasons and in the absence of any information to the contrary, the staff concluded that the activities to be performed will not be inimical to the common defense and security.

16.0 FINANCIAL QUALIFICATIONS

The Commission's regulations which relate to the financial data and information required to establish financial qualifications for an applicant for an operating license are 10 CFR 50.33(f) and 10 CFR 50, Appendix C. The basic application of Duke Power Company, as amended, and the accompanying certified annual financial statements of the applicant provide the financial information required by the Commission's regulations. This information includes the estimated annual costs of operating the Oconee Nuclear Station, Units 2 and 3, for the first five years of operation plus the estimated cost of permanently shutting down the facility and maintaining it in a safe shutdown condition.

The staff's evaluation of the financial data submitted by the applicant, summarized below, provides reasonable assurance that the applicant possesses or can obtain the necessary funds to meet the requirements of 10 CFR 50.33(f) to operate the Oconee Nuclear Station, Units 2 and 3, and, if necessary, permanently shut down the facility and maintain it in a safe shutdown condition.

Operating revenues derived from system-wide operations will provide the funds to cover cost of operations. The annual costs to operate each unit for a five year period are presently estimated by the applicant to be $28.0 million. This includes costs for interest; depreciation; property taxes; insurance; overhead; operating labor; materials and supplies; and fuel costs. In addition, the applicant estimates the cost of permanently shutting down both units will be about $5 million. It is estimated that an annual cost of $77,000 will be incurred thereafter to maintain both units of the facility in a safe shutdown condition.

Amounts required to permanently shut down the facility and maintain it in a safe shutdown condition will be obtained from electrical operating revenues derived from system-wide operations.

The staff has examined the financial information submitted by Duke Power Company to determine whether it is financially qualified to meet the above estimated costs. The information contained in Duke's calendar year 1971 financial report indicates that operating revenues for 1971 totaled $451.5 million; operating expenses and taxes were 369.5 million, of which $53.1 million represented depreciation. The interest on long-term debt was earned 2.4 times; and the net income for the year was $71.8 million, of which $57.1 million was distributed as dividends to stockholders and the remainder of $14.7 million was retained for use in the business. As of December 31, 1971, the company's assets totaled $2,102.3 million, most of which was invested in utility plant ($1,925.4 million); retained earnings amounted to $81.8 million. Financial ratios computed from the 1971 statements indicate an adequate financial condition, e.g., long-term debt to total capitalization - 0.55, and to net utility plant - 0.54; net plant to capitalization - 1.02; the operating ratio - 0.82; and the rates of return on common - 9.6%, on stockholders' investment - 8.4%, and on total investment - 6.4%. The record of

Duke's operations over the past 5 years reflects that operating revenues increased from $258.7 million in 1966 to $451.5 million in 1971; net income increased from $45.8 million to $71.8 million; and net investment in plant from $769.7 million in 1966 to $1,925.4 million; while the number of times interest earned declined from 3.9 in 1967 to 2.4 in 1971. Moody's Investors Service rates the company's first mortgage bonds as Aa (high quality). The company's current Dun and Bradstreet credit rating is 5A1.

A copy of the staff's financial analysis of the company reflecting these ratios and other pertinent financial data is attached as Appendix B to this supplement.

17.0 FINANCIAL PROTECTION AND INDEMNITY REQUIREMENTS

Pursuant to the financial protection and indemnification provisions of the Atomic Energy Act of 1954, as amended (Section 170 and related sections), the Commission has issued regulations in 10 CFR Part 140. These regulations set forth the Commission's requirements with regard to proof of financial protection by, and indemnification of, licensees for facilities such as power reactors under 10 CFR Part 50.

The Commission's regulations in Part 140 require that each holder of a construction permit under 10 CFR Part 50, who is also the holder of a license under 10 CFR Part 70 authorizing the ownership and possession for storage only of special nuclear material at the reactor construction site for future use as fuel in the reactor (after issuance of an operating license under 10 CFR Part 50), shall, during the interim storage period prior to licensed operation, have and maintain financial protection in the amount of $1,000,000 and execute an indemnity agreement with the Commission. Proof of financial protection is to be furnished prior to, and the indemnity agreement executed as of, the effective date of the 10 CFR Part 70 license. Payment of an annual indemnity fee is required.

Duke Power Company has furnished to the Commission proof of financial protection in the amount of $1,000,000 in the form of a Nuclear Energy Liability Insurance Association policy (Nuclear Energy Liability Policy, facility form) No. NF-182.

Further, Duke Power Company executed Indemnity Agreement B-44 with the Commission as of (March 24, 1970) the effective date of its preoperational fuel storage license, (SNM-1180). Amendment 2 to Indemnity Agreement B-44, dated August 31, 1971, added activities under preoperational fuel storage license SNM-1271 to the coverage of the indemnity agreement. Duke Power Company has paid the annual indemnity fee applicable to preoperational fuel storage.

Under the Commission's regulations, 10 CFR Part 140, a license authorizing the operation of a reactor may not be issued until proof of financial protection in the amount required for such operation has been furnished, and an indemnity agreement covering such operation (as distinguished from preoperational fuel storage only) has been executed. The amount of financial protection which must be maintained for Oconee Nuclear Power Station (which has a rated capacity of more than 100,000 electrical kilowatts for reactor unit) is the maximum amount available from private sources, i.e., the combined capacity of the two nuclear liability insurance pools, which amount is currently $95 million. Accordingly, no license authorizing operation of the Oconee Nuclear Power Plants will be issued until proof of financial protection in the requisite amount has been received and the requisite indemnity agreement executed.

The staff expects that, in accordance with the usual procedure, the nuclear liability insurance pools will provide, several days in advance of anticipated issurance of the operating license document, evidence in writing, on behalf of the applicant, that the present coverage has been appropriately amended so that the policy limits have been increased, to meet the requirements of the Commission's regulations for reactor operation.

Similarly, no operating license will be issued until an appropriate amendment to the present indemnity agreement has been executed. Duke Power Company will be required to pay an annual fee for operating license indemnity as provided in our regulations, at the rate of $30 per each thousand kilowatts of thermal capacity authorized in its operating license.

On the basis of the above considerations, the staff concludes that the presently applicable requirements of 10 CFR Part 140 have been satisfied and that, prior to issuance of the operating licenses, the applicant will be required to comply with the provisions of 10 CFR Part 140 applicable to operating licenses, including those as to proof of financial protection in the requisite amount and as to execution of an appropriate indemnity agreement with the Commission.

18.0 CONCLUSIONS

Based on the evaluation of the application as set forth above, the staff concluded that:

1. The application for facility licenses filed by the Duke Power Company dated November 28, 1966, as amended (Amendments Nos. 1 through 41) complies with the requirements of the Atomic Energy Act of 1954, as amended (Act), and the Commission's regulations set forth in 10 CFR Chapter 1; and
2. Construction of Oconee Nuclear Power Plants (the facility) have proceeded and there is reasonable assurance that they will be substantially completed, in conformity with Provisional Construction Permits Nos. CPPR 34 and 35, the application as amended, the provisions of the Act, and the rules and regulations of the Commission; and
3. The facility will operate in conformity with the application as amended, the provisions of the Act, and the rules and regulations of the Commission; and
4. There is reasonable assurance (i) that the activities authorized by the operating licenses can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the regulations of the Commission set forth in 10 CFR Chapter 1; and

5. The applicant is technically and financially qualified to engage in the activities authorized by these licenses, in accordance with the regulations of the Commission set forth in 10 CFR Chapter 1; and

6. The issuance of these licenses will not be inimical to the common defense and security or to the health and safety of the public.

Before operating licenses will be issued to the Duke Power Company for operation of the Oconee Units 2 and 3, the units must be completed in conformity with the provisional construction permits, the application, the Act, and the rules and regulations of the Commission. Such completeness of construction as is required for safe operation at the authorized power level must be verified by the Commission's Directorate of Regulatory Operations prior to license issuance. Further, before operating licenses are issued, the applicant will be required to satisfy the applicable provisions of 10 CFR Part 140.

APPENDIX A

CHRONOLOGY OF REGULATORY REVIEW OF THE DUKE POWER COMPANY OCONEE NUCLEAR STATION UNIT NOS. 2 AND 3 SUBSEQUENT TO THE ORIGINAL SAFETY EVALUATION REPORT ISSUED DECEMBER 29, 1970 (SINCE DECEMBER 14, 1970)

DATE	
1. December 30, 1970	Application Amendment No. 25 provided Revision 15 to the FSAR, the "Reactor Building Structural Instrumentation Report," dated December 30, 1970 and incorporated two B&W topical reports, BAW-1363 and BAW-1364 on Analysis and Resolution of Dye Penetrant Indications in reactor coolant system piping and elbows.
2. February 11 & 12, 1971	Site visit to Oconee to view Instrumentation and Electrical Systems.
3. March 29, 1971	Application Amendment No. 26 provided Anti-trust information.
4. July 30, 1971	Application Amendment No. 27 provided Revision 16 to the FSAR, minor design revisions for Oconee Units 2 and 3 and technical specifications for Unit 1.

5.	September 30, 1971	Duke letter to Licensing transmitting a Control Rod Drive Damage Report for Oconee Unit 1.
6.	August 6, 1971	Application Amendment No. 28 provided proprietary information on results of fuel assembly flow area measurements and acceptance criteria for measured vibrations of the core support shield during hot functional tests.
7.	December 17, 1971	Application Amendment No. 29 provided Revision 17 to the FSAR, ECC information regarding the Commission's interim acceptance criteria for ECCS and incorporated B&W topical reports BAW-10030, BAW-10031, BAW-10033 and BAW-10034 all dealing with LOCA analysis.
8.	January 19, 1972	Meeting at Bethesda with Duke to discuss Instrument and Control Cables installation.
9.	February 10, 1972	Meeting at Bethesda, with Duke and B&W to discuss all unresolved items.
10.	March 2, 1972	Duke letter to Licensing supplementing the Structural Integrity Test Report and providing information on the failure of imbedded gauges.

11.	March 8, 1972	Duke letter to Licensing on Inservice Inspection for Corrosive Leaks in the Primary System.
12.	March 10, 1972	Application Amendment No. 30 provided Revision 18 to the FSAR, response to our letter of December 6, 1971 on control rod drive damage and response to our letter of January 26, 1972 on separation of redundant instrument and control cables.
13.	March 29-30, 1972	Site visit to Oconee to discuss technical specifications and view Unit 1 internals and steam generator damage.
14.	April 6, 1972	Meeting at Barberton with B&W to discuss steam generator repairs for Oconee Unit 1.
15.	May 5, 1972	Application Amendment No. 31 provided Revision 19 to the FSAR, information on net positive suction head for safety equipment pumps and revision to the Unit 1 technical specifications.
16.	May 11, 1972	Meeting at Bethesda with B&W to discuss control rod drive motor tube defects.

17.	May 24, 1972	Meeting at Bethesda with B&W and Duke to discuss repair of steam generator and vessel internals.
18.	May 25, 1972	Application Amendment No. 32 provided Revision 20 to the FSAR, and information in response to our letter of April 27, 1972 containing Unit 2/3 review questions.
19.	June 6, 1972	Meeting at Diamond Power with B&W to discuss control rod drive motor tube repairs.
20.	June 15, 1972	Meeting at Bethesda with Duke and B&W to discuss operating crew size.
21.	June 15, 1972	Meeting at Bethesda with Duke and B&W to discuss Technical Specifications.
22.	June 16, 1972	Meeting at Bethesda with Duke and B&W to discuss mechanical engineering information.
23.	July 12-13, 1972	Site visit to Oconee to discuss plant staffing, emergency procedures and industrial security.

24.	July 26, 1972	Application Amendment No. 33 provided Revision 21 to the FSAR, a revised list of all B&W topical reports applicable to this application, information voluntarily submitted on dynamic response of building, piping and systems and revisions to the Oconee Unit 1 Technical Specifications.
25.	August 7, 1972	Meeting at Bethesda with Duke and B&W to discuss vibration monitoring of vessel internals.
26.	August 7, 1972	Meeting at Bethesda with Duke to discuss Oconee site hydrology.
27.	August 23, 1972	Duke letter to Licensing in response to our letter to Duke of July 26, 1972 regarding radial tilt limits.
28.	August 25, 1972	Application to Amendment No. 34 provided Revision 22 to the FSAR, revisions to the Oconee Unit 1 Technical Specifications to include Units 2 and 3 and response to our letter of July 13, 1972 on the flood tank line rupture analysis.

29.	September 11, 1972	Duke letter to Licensing requesting reconsideration of our position on operating crew size for multi-unit operation.
30.	September 15, 1972	Application Amendment No. 35 provided Revision 23 to the FSAR, requested financial data for Units 2/3, incorporated B&W topical reports dealing with the internals failure and redesign in Unit 1 and revisions to the Unit 1 Technical Specifications.
31.	October 16, 1972	Application Amendment No. 36 provided supplemental and revised financial data for Units 2/3.
32.	October 17, 1972	Meeting at Bethesda with Duke and B&W to discuss Quadrant Tilt, Technical Specifications for Units 2/3, Environmental Specs and Industrial Security.
33.	October 24, 1972	Duke letter to Licensing regarding review of Non-Category I equipment.
34.	October 25, 1972	Meeting at Bethesda with Duke and B&W to discuss reactor vessel internals redesign and vibration monitoring.

35.	November 3, 1972	Meeting at Bethesda with Duke and B&W to discuss ECCS topics.
36.	November 3, 1972	Meeting at Bethesda with Duke and B&W to discuss Containment Response analysis.
37.	November 15, 1972	Application Amendment No. 37 provided Revision 24 to the FSAR, Unit 2/3 Technical Specifications, and incorporated B&W topical reports dealing with vessel internals, small break analysis and qualification testing of protective system instrumentation.
38.	November 17, 1972	Meeting at Bethesda with Duke and B&W to discuss ECCS analysis.
39.	November 20, 1972	Duke letter to Licensing describing design basis for auxiliary service water system.
40.	December 1, 1972	Meeting at Bethesda with Duke and B&W to discuss Core Floodline Break analysis.
41.	December 7, 1972	Duke letter to Licensing regarding minimum shift crew size.

42.	December 13, 1972	Application Amendment No. 38 provided Revision 25 to the FSAR, revised Oconee Unit 1 Technical Specifications and incorporated B&W topical reports dealing with model flow tests and prototype vibration measurements for reactor internals.
43.	December 15, 1972	Meeting at Bethesda with Duke and B&W to discuss Core Floodline Break Analysis.
44.	December 19, 1972	Duke letter to Licensing transmitting Reflood and Small Break Analyses.
45.	December 19, 1972	Duke letter to Licensing transmitting containment pressure analysis.
46.	December 20, 1972	Visit to Oconee site to discuss vessel internals vibration tests.
47.	December 29, 1972	Duke letter to Licensing responding to high energy line rupture request.
48.	January 4, 1973	Meeting at Bethesda with Duke and B&W to discuss floodline flow limiters.
49.	January 12, 1973	Duke letter to Licensing transmitting fuel densification reports.

50.	January 12, 1973	Duke letter to Licensing regarding flow limiter installation in floodlines.
51.	January 18, 1973	Meeting at Bethesda with Duke on high energy line rupture analysis.
52.	January 19, 1973	Visit to Oconee site to inspect vessel internals following preoperational tests.
53.	January 26, 1973	Meeting at Bethesda with Duke and B&W on Core Floodline Break analysis.
54.	January 26, 1973	Duke letter to Licensing stating interim position on high energy line rupture protection.
55.	January 29, 1973	Application Amendment No. 39 provided Revision 26 to the FSAR and incorporated B&W topical reports dealing with fuel densification.
56.	January 31, 1973	Meeting at Bethesda with Duke and B&W on fuel densification.
57.	January 31, 1973	Meeting at Bethesda with Duke and B&W on vessel internals design.
58.	February 1, 1973	Duke letter to Licensing with regard to manual control of reactor core cooling water.

59.	February 5, 1973	Duke letter to Licensing describing interim protective measures taken against high energy line rupture.
60.	February 15, 1973	Duke letter to Licensing transmitting vibration test data from vessel internals in Oconee 1 preoperational tests.
61.	February 20, 1973	Meeting at Bethesda with Duke and B&W on fuel densification.
62.	March 1 and 2, 1973	Visit to B&W Lynchburg fuel fabrication facilities to discuss fuel densification.
63.	March 2, 1973	Duke letter to Licensing transmitting subcompartment pressure analysis.
64.	March 14, 1973	Visit to Westinghouse facilities to view core uncovery test facility.
65.	March 21, 1973	Meeting at Germantown and Bethesda with Duke and B&W on fuel densification.
66.	April 3, 1973	Meeting with Duke and B&W on ECCS
67.	April 6, 1973	Meeting with Duke and B&W on fuel densification.
68.	April 12, 1973	Duke letter to Licensing transmitting ECCS data from Westinghouse Uncovering Tests.

69.	April 13, 1973	Application Amendment No. 40 provided Revision 27 to the FSAR and incorporated revised fuel densification reports.
70.	April 25, 1973	Duke letter to Licensing transmitting Report No. 05-73.2, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment for Oconee Nuclear Station Units 1, 2 and 3.
71.	April 27, 1973	Duke letter to Licensing transmitting QA for Operations Program.
72.	May 1, 1973	Duke letter to Licensing transmitting review of Active Valve Operability.
73.	May 1, 1973	Application Amendment No. 41 provided Revision 28 to the FSAR and incorporated B&W topical reports related to fuel densification, vessel internals and ECCS.
74.	May 3, 1973	Duke letter to Licensing transmitting review of control circuits.
75.	May 8, 1973	Meeting with Duke and B&W on fuel densification.
76.	May 15, 1973	Meeting with Duke and B&W on fuel densification.

APPENDIX B

DUKE POWER COMPANY
DOCKET NOS. 50-270 and 50-287
FINANCIAL ANALYSIS

	(dollars in millions) Calendar Year Ended December 31		
	1971	1970	1969
Long-term debt	$ 1,040.9	$ 837.5	$ 663.8
Utility plant (net)	1,925.4	1,631.8	1,296.6
Ratio - debt to fixed plant	0.54	0.51	0.51
Utility plant (net)	1,925.4	1,631.8	1,296.6
Capitalization	1,895.9	1,509.8	1,204.9
Ratio of net plant to capitalization	1.02	1.08	1.08
Stockholders' equity	855.0	672.3	541.1
Total assets	2,102.3	1,778.0	1,399.0
Proprietary ratio	0.41	0.38	0.39
Earnings available to common equity	55.5	40.0	47.4
Common equity	580.0	457.3	386.1
Rate of earnings on common equity	9.6%	8.7%	12.3
Net income	71.8	51.2	54.4
Stockholders' equity	855.0	672.3	541.1
Rate of earnings on stockholders' equity	8.4%	7.6%	10.0
Net income before interest	134.2	102.7	93.3
Liabilities and capital	2,102.3	1,778.0	1,339.0
Rate of earnings on total investment	6.4%	5.8%	6.7
Net income before interest	134.2	102.7	93.3
Interest on long-term debt	54.9	42.3	29.0
No. of times long-term interest earned	2.44	2.43	3.22
Net income	71.8	51.2	54.4
Total revenues	503.7	420.5	363.5
Net income ratio	0.14	0.12	0.15
Total utility operating expenses	369.5	317.8	270.2
Total utility operating revenues	451.5	386.1	342.2
Operating ratio	0.82	0.82	0.79

	(dollars in millions) Calendar Year Ended December 31		
	1971	1970	1969
Utility plant (gross)	2,459.6	2,126.2	1,750.5
Utility operating revenues	451.5	386.1	342.2
Ratio of plant investment to revenues	5.4	5.51	5.11

	1971		1970	
Capitalization:	Amount	% of Total	Amount	% of Total
Long-term debt	$ 1,040.9	54.9%	$ 837.5	55.5%
Preferred stock	275.0	14.5	215.0	14.2
Common stock & surplus	580.0	30.6	457.3	30.3
Total	$ 1,895.9	100.0%	$ 1,509.8	100.0%

Moody's Bond Rating: First Mortgage Aa
Debenture A

Dun & Bradstreet Credit Rating: 5A1

U.S. DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
ENVIRONMENTAL RESEARCH LABORATORIES
Silver Spring, Maryland 20910

October 26, 1972

R323

APPENDIX C

Dr. Joseph M. Hendrie
Deputy Director for Technical Review
Directorate of Licensing, USAEC
Washington, D. C. 20545

50-269
50-270
50-287

Dear Dr. Hendrie:

This refers to the letter of October 20, 1972, from R. C. DeYoung, Assistant Director for Pressurized Water Reactors, Directorate of Licensing, requesting additional comments on the following:

Oconee Nuclear Station Unit 1
Duke Power Company
Final Safety Analysis Report
Amendment No. 30 dated March 10, 1972
Amendment No. 32 dated May 25, 1972

These comments are attached.

Sincerely,

Isaac Van der Hoven

Isaac Van der Hoven, Chief
Air Resources Environmental Lab.
Air Resources Laboratories

Attachment

cc: E. H. Markee, USAEC

3111

U.S. DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
ENVIRONMENTAL RESEARCH LABORATORIES

Comments on

Oconee Nuclear Station Unit 1
Duke Power Company
Final Safety Analysis Report
Amendment No. 30 dated March 10, 1972
Amendment No. 32 dated May 25, 1972

Prepared by

Air Resources Environmental Laboratories
National Oceanic and Atmospheric Administration
October 26, 1972

Amendment 30 contains new meteorological data for the period March 15, 1970, through March 14, 1972, during which Lake Keowee was filled with water and the wind calibration problems previously cited were resolved. We consider these data to be the best available and representative of the site as it now exists and, consequently, have used the information as the basis for our diffusion analysis.

We understand that the location of the meteorological tower is still within a stand of tall trees. Because of the wooded nature of the terrain, we feel that the measurement of wind speeds at 150 feet above the ground and reduced by a logarithmic relationship to the 100-ft level would most nearly represent the ambient flow of air from the reactor complex at a height of 30 feet above the surface.

For the short-term (0-2 hours) release we estimate from the data presented in Table 2.1-1 that a relative concentration of 2×10^{-4} sec m^{-3} will be exceeded 5 percent of the time at the exclusion distance of 1600 m. We assumed a building wake factor of $cA = 1270\ m^2$. Since neither wind persistence or monthly wind statistics were presented, we have not made diffusion analyses of the 24-hour and 30-day periods.

For the average annual concentration we have concluded that the maximum value will occur at the exclusion distance with winds occurring from the north resulting in a value of 3×10^{-6} sec m^{-3}.

50-269
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50-287

LBC&W ASSOCIATES OF SOUTH CAROLINA ■ 1800 GERVAIS STREET, COLUMBIA, SOUTH CAROLINA 29202

November 15, 1972

Mr. L. G Hulman
Senior Hydraulic Engineer
Site Analysis Branch
Directorate of Licensing
Atomic Energy Commission
7920 Norfolk Avenue
Bethesda, Maryland 20014

Dear Mr. Hulman

1. In accordance with contract # AT(49-24)-008, dated 31 October 1972, and associated understandings, I have made hydrologic engineering studies pertaining to the Keowee-Toxaway development of the Duke Power Company's Oconee Nuclear Station in Oconee County, South Carolina. A concise summary of my findings and conclusions is presented herein. Supporting technical details in documented form are available for your review if desired.

2. The assignment related specially to the following:

a. Computation of probable maximum flood (PMF) hydrographs of inflow into Jocassee and Keowee Reservoirs, respectively;

b. Routing of the PMF hydrographs through Jocassee and Keowee Reservoirs under critical assumptions, to determine hydrographs of reservoir stages and outflow rates;

c. Computation of wave characteristics and vertical heights of runup on embankments of the Jocassee, Keowee and Little River Dams, respectively, that might coincide with maximum reservoir stages during the probable maximum floods;

d. A summary of conclusions regarding estimates referred to above, particularly as they relate to the safety of the dams against failure during extreme floods.

3. The policy concepts, methods, hydrometeorological criteria, and basic flood routing assumptions adhered to in the assignment conform essentially with those adopted by the Atomic Energy Commission to govern the determination of spillway capacities and freeboard requirements for very large dams, generally as summarized in the February 1972 draft, Standard Format and Contents of Safety Analysis Reports for Nuclear Power Plants.

PERTINENT DATA

4. Following is a brief summary of physical features that relate to the studies:

a. Keowee Lake, controlling 439 square miles, is formed by a 150-foot high earthfill dam on the Keowee River and a 170-foot high earthfill dam on Little River; a "connecting canal" joins lakes formed by these two dams, and is large enough to allow the two lakes to act as one. The Keowee and Little River Dams each have top elevations of 815' msl. On each dam the upstream embankment is surfaced with dumped rock for erosion protection above elevation 772' msl, which has a slope at 1' V to 2.0' H. The downstream embankment has a slope of 1' V to 2.5' H.

b. The 385-foot high rockfill Jocassee Dam, located about 12 miles upstream from Keowee Dam, controls 148 square miles of the total 439 square mile basin above the Keowee-Little River Dams. The top elevation of the embankment is 1125' msl. Upstream and downstream rockfill embankments each have a slope of 1' V to 1.75' horizontal in the upper 100 feet of elevation, which includes the zone considered in estimating potential wave runup effects.

c. Keowee Lake has a gross storage capacity of 956,000 acre-feet at a normal full-pool elevation of 800' msl, with a surface area of 18,372 acres (29 square miles). The Jocassee Reservoir has a gross storage capacity of 1,160,000 acre-feet at a normal full-pool elevation of 1,110 feet msl, and a surface area of 7565 acres (12 square miles).

d. The Keowee Dam spillway consists of four tainter gates, 38' W x 35' H, with a crest elevation of 765' msl and a total discharge capacity of 106,000 cubic feet per second at a normal full-pool level of 800' msl. The Jocassee spillway has two tainter gates, 38' W x 33' H, crest elevation 1077' msl, with a combined capacity of 46,200 cfs at a normal full-pool level of 1,110 msl.

e. In addition to spillways, the Keowee and Jocassee Dams have power turbines capable of discharging substantial quantities of water. Operating plans for Jocassee Dam provide for releases up to 15,000 cfs through power turbines to augment spillway discharges during floods, if needed. However, such turbine operations could be precluded by interruptions in power loadings or for other reasons under emergency conditions associated with extreme floods. Accordingly, in the studies reported herein, releases through power turbines were assumed as zero in routing the Probable Maximum Flood through the reservoirs.

CRITICAL FLOOD ESTIMATES

5. Probable Maximum Precipitation (PMP) estimates for the 439 square mile basin above Keowee Lake, and relevant sub-division thereof, were obtained from Hydrometeorological Report No. 33 of the U. S. Weather Bureau (now NOAA). Alternative areal distributions of PMP quantities were tested to develop critical flood producing relations. The Probable Maximum Flood from the 148 square mile basin above Jocassee Dam would result when the heaviest PMP concentration occurred over this area; the critical PMF hydrograph at Keowee Dam would result with the heaviest PMP amounts concentrated over the 291 square mile intermediate area between Jocassee and the dams forming Keowee Lake. PMF hydrographs were computed by application of synthetic unit hydrographs to estimates of PMP rainfall-excess assuming an infiltration index of .05 inch per hour. The synthetic unit hydrographs were derived for component drainage areas tributary to full reservoirs to account for the accelerating effects of unusually large water surfaces of Lake Keowee and Lake Jocassee at normal full-pool elevations, which represent more than 9 percent of the total 439 square mile drainage area. The selection of coefficients used in developing synthetic unit hydrographs were based on studies of unit hydrographs derived from analyses of major floods.

6. The computed PMF hydrograph of inflow into Jocassee Lake had a peak of 245,000 cfs, and a runoff volume of 210,000 acre-feet (26.6 inches runoff from 148 sq. mi.). Assuming the reservoir would be filled to elevation 1,110' msl at the beginning of the PMF, and all releases made through the two spillway gates, a peak reservoir stage of 1,122.5' msl was computed; stages exceeding 1,119.7' msl would prevail for 12 hours. The peak rate of reservoir outflow through the spillway would be 72,000 cfs.

7. The computed PMF hydrograph of inflow into Lake Keowee had a peak of 450,000 cfs, and a runoff volume of 550,000 acre-feet (23.5 inches runoff from 439 square miles). Assuming the reservoir would be initially filled to elevation 800' msl, and all releases made through the four spillway gates, a peak reservoir level of 809.8' msl was computed; levels exceeding 806.6' msl would prevail for 12 hours. These values are predicated on the assumption that all concurrent releases from Jocassee Reservoir are made through the spillway, without flows through power turbines.

FREEBOARD FOR WAVE ACTION

8. Following is a review of the apparent adequacy of existing dams to safely accommodate wave action in Lake Jocassee and Lake Keowee in the event high winds blowing toward the dams should prevail for several hours while reservoir levels are equal to or near the maximum elevations indicated for PMF conditions. Relevant procedures and computational aids contained in publications by the Army Corps of Engineers (EC 1110-2-27, and ETL 1110-2-8, dated 1 August 1966) were used in the analyses.

9. Wind records and analyses show that wind velocities as high as 35 to 40 miles per hour over-land, for durations of 1 to 6 hours, may occur infrequently in the vicinity of Lake Jocassee and Lake Keowee. Research studies indicate that over-land wind velocities of 35 to 40 mph would accelerate approximately 25 percent over the open water surfaces near the dams - that is to over-water velocities of 44 to 50 mph. Whether or not such winds might coincide with peak reservoir levels during the PMF, and be oriented over the "effective fetch" in a critical direction toward the respective dams, is largely a matter of conjecture. In general, studies show that wind directions tend to change substantially over local areas as storm centers move, even though velocities in various directions may persist at high rates for several hours. In general recognition of the improbability of the most critical wind velocity-duration-direction relations coinciding with maximum reservoir levels, the publications cited above provide for adoption of "design wind" criteria that are considered reasonable on the basis of available data and design objectives involved. Estimates based on these criteria are used as aids to over-all judgement of possible wave effects on project features. In the instant case, a "design wind" corresponding to an over-land velocity of 25 mph for a period of 6 hours was considered reasonable in estimating heights of runup that might be expected during the PMF. However, the possible effects of wave action that could conceivably result from winds equal to 40 mph over-land were also considered to assure that hazards from possible breaching of the dams from wave erosion would not exist even during extreme conditions. (Wind velocities cited herein refer to "over-land" rates; however, corrections for velocity increases over water have been accounted for in wave computations).

10. The Jocassee Dam top elevation of 1125' msl provides a freeboard of 2.5' above the computed maximum reservoir level during the PMF elevation 1122.5' msl. Computations indicate that a sustained wind velocity equivalent to 25 mph over-land, acting on a 2.5-mile "effective fetch," could result in "significant waves" (h_s) 1.9 feet high, which would break and run up the face of Jocassee Dam to a vertical height of approximately 2.5 feet above reservoir levels prevailing during the PMF; a negligible amount of wave splash or over-wash from waves exceeding h_s might pass over the crest of the dam. For corresponding conditions, a sustained wind velocity equal to 40 mph over-land would produce runup approximately 1.5 feet higher, and moderate amounts of wave-splash and wave over-wash might pass over the crest of the dam for a period of a few hours. In view of the characteristics of the rockfill embankments of Jocassee Dam, it is concluded that this wave action would not be sufficient to represent any risk of breaching of the embankment of Jocassee Dam.

11. The Keowee Dam top elevation of 815' msl provides a freeboard of 5.2 feet above the computed maximum reservoir level during the PMF elevation 809.8' msl. A sustained wind velocity comparable to 40 mph over-land, blowing toward the dam over an effective fetch of 2.2 miles would produce significant waves 3.2' high, capable of running up 4.0 feet on the riprap embankment (slope 1:2); the maximum wave in a spectrum of 100 waves would run up about one foot higher. Accordingly, computations indicate that Keowee Dam is high enough to prevent wave over-wash under the most cirtical PMF conditions. The same conclusion is applicable to Little River Dam, where the effective fetch (1.9 miles) is less than for the Keowee Dam.

CONCLUSIONS

12. Procedures and Criteria. The policy concepts, methods, hydrometeorological criteria, and basic flood routing assumptions used in the subject studies are consistent with sound engineering practices associated with the design of very large dams in the United States; they foster a safe degree of conservatism in evaluations pertaining to the projects covered by this report.

13. Jocassee Dam and Reservoir.

a. The Probable Maximum Flood hydrograph of inflow into Lake Jocassee would have a peak discharge of approximately 245,000 cfs, and a runoff volume of 210,000 acre-feet.

b. A maximum reservoir level of 1,122.5' msl could be attained in Lake Jocassee during the PMF under the most adverse circumstances considered reasonably possible.

c. The top elevation of 1,125' msl of Jocassee Dam provides a freeboard allowance for possible wave runup on the rockfill embankment equal to 2.5 feet above the peak PMF reservoir level (1,122.5' msl) estimated herein. It is remotely possible that sustained wind velocities (equal to 25 to 40 mph over land), blowing toward the dam could cause wave runup and some wave over-wash of the Jocassee embankment for a few hours during the PMF. However, the rockfill composition of the dam embankment is such as to preclude breaching of the embankment from wave wash of the general magnitude indicated.

14. Keowee and Little River Dams.

a. The Probable Maximum Flood Hydrograph of inflow into Lake Keowee would have a peak discharge of approximately 450,000 cfs and a runoff volume of 550,000 acre-feet.

b. A maximum reservoir level of approximately 810.' msl could be attained in Lake Keowee during the PMF under the most critical circumstances considered reasonably possible.

c. It is remotely possible that sustained wind velocities (40 mph or less over land), blowing toward the dams during the PMF could cause wave runup on the riprap covered face of each dam approaching crest elevation 815' msl.

Albert L. Cochran

ALBERT L. COCHRAN
Director of Special Projects
Lyles, Bissett, Carlisle & Wolff

ALC:ad

APPENDIX E

GENERAL INFORMATION REQUIRED FOR CONSIDERATION OF THE EFFECTS OF A PIPING SYSTEM BREAK OUTSIDE CONTAINMENT

The following is a general list of information required for AEC review of the effects of a piping system break outside containment, including the double-ended rupture of the largest pipe in the main steam and feedwater systems, and for AEC review of any proposed design changes that may be found necessary. Since piping layouts are substantially different from plant to plant, applicants and licensees should determine on an individual plant basis the applicability of each of the following items for inclusion in their submittals.

1. The systems (or portions of systems) for which protection against pipe whip is required should be identified. Protection from pipe whip need not be provided if any of the following conditions will exist:
    a. Both of the following piping system conditions are met:
        (1) the service termperature is less than 200°F; and
        (2) the design pressure is 275 psig or less: or
    b. The piping is physically separated (or isolated) from structures, systems, or components important to safety by protective barriers, or restrained from whipping by plant design features, such as concrete encasement: or

c. Following a single break, the unrestrained pipe movement of either end of the ruptured pipe in any possible direction about a plastic hinge formed at the nearest pipe whip restraint cannot impact any structure, system, or component important to safety; or

d. The internal energy level[1] associated with the whipping pipe can be demonstrated to be insufficient to impair the safety function of any structure, system, or component to an unacceptable level.

2. "Design basis break locations should be selected in accordance with the following pipe whip protection criteria; however, where pipes carrying high energy fluid are routed in the vicinity of structures and systems necessary for safe shutdown of the nuclear plant, supplemental protection of those structures and systems shall be provided to cope with the environmental effects (including the effects of jet impingement) of a single postulated open crack at the most adverse location(s) with regard to those essential structures and systems, the length of the crack being chosen not to exceed the critical crack size. The critical crack size is taken to be 1/2 the pipe diameter in length and 1/2 the wall thickness in width."

The criteria used to determine the design basis piping break locations in the piping systems should be equivalent to the following:

a. ASME Section III Code Class I piping[2] breaks should be postulated to occur at the following locations in each piping run[3] or branch run:

   (1) the terminal ends;

   (2) any intermediate locations between terminal ends where the primary plus secondary stress intensities S_m (circumferential or longitudinal) derived on an elastically calculated basis under the loadings associated with one-half safe shutdown earthquake and operational plant conditions[4] exceeds 2.0 S_m[5] for ferritic steel, and 2.4 S_m for austenitic steel;

   (3) any intermediate locations between terminal ends where the cumulative usage factor (U)[6] derived from the piping fatigue analysis and based on all normal, upset, and testing plant conditions exceeds 0.1; and

   (4) at intermediate locations in addition to those determined by (1) and (2) above, selected on a reasonable basis as necessary to provide protection. As a minimum, there should be two intermediate locations for each piping run or branch run.

b. ASME Section III Code Class 2 and 3 piping breaks should be postulated to occur at the following locations in each piping run or branch run:

(1) The terminal ends:

(2) any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with seismic events and operational plant conditions exceed 0.8 $(S_h + S_A)$[7] or the expansion stresses exceed 0.8 S_A; and

(3) intermediate locations in addition to these determined by (2) above, selected on reasonable basis as necessary to provide protection. As a minimum, there should be two intermediate locations for each piping run or branch run.

3. The criteria used to determine the pipe break orientation at the break locations as specified under 2 above should be equivalent to the following:

a. Longitudinal[8] breaks in piping runs and branch runs, 4 inches nominal pipe size and larger, and/or

b. Circumferential[9] breaks in piping runs and branch runs exceeding 1 inch nominal pipe size.

4. A summary should be provided of the dynamic analyses applicable to the design of Category I piping and associated supports which determine the resulting loadings as a result of a postulated pipe break including:

   a. The locations and number of design basis breaks on which the dynamic analyses are based.

   b. The postulated rupture orientation, such as a circumferential and/or longitudinal break(s), for each postulated design basis break location.

   c. A description of the forcing functions used for the pipe whip dynamic analyses including the direction, rise time, magnitude, duration and initial conditions that adequately represent the jet stream dynamics and the system pressure difference.

   d. Diagrams of mathematical models used for the dynamic analysis.

   e. A summary of the analyses which demonstrates that unrestrained motion of ruptured lines will not damage to an unacceptable degree, structure, systems, or components important to safety, such as the control room.

5. A description should be provided fo the measures, as applicable, to protect against pipe whip, blowdown jet and reactive forces including:

   a. Pipe restraint design to prevent pipe whip impact:

b. Protective provisions for structures, systems, and components required for safety against pipe whip and blowdown jet and reactive forces:

c. Separation of redundant features:

d. Provisions to separate physically piping and other components of redundant features; and

e. A description of the typical pipe whip restraints and a summary of number and location of all restraints in each system.

6. The procedures that will be used to evaluate the structureal adequacy of Category I structures and to design new seismic Category I structures should be provided including:

   a. The method of evaluating stresses, e.g., the working stress method and/or the ultimate strength method that will be used;

   b. The allowable design stresses and/or strains; and

   c. The load factors and the load combinations.

7. The structural design loads, including the pressure and temperature transients, the dead, live and equipment loads; and the pipe and equipment statis, thermal, and dynamic reactions should be provided.

8. Seismic Category I structural elements such as floors, interior walls, exterior walls, building penetrations and the buildings as a whole should be analyzed for eventual reversal of loads due to the postulated accident.

9. If new openings are to be provided in existing structures, the capabilities of the modified structures to carry the design loads should be demonstrated.

10. Verification that failure of any structure, including nonseismic Category I structures, caused by the accident, will not cause failure of any other structure in a manner to adversely affect:
    a. Mitigation of the consequences of the accidents; and
    b. Capability to bring the unit(s) to a cold shutdown condition.

11. Verification that rupture of a pipe carrying high energy fluid will not directly or indirectly result in:
    a. Loss of required redundancy in any portion of the protection system (as defined in IEEE-279), Class IE electric system (as defined in IEEE-308), engineered safety feature equipment, cable penetrations, or their interconnecting cables required to mitigate the consequences of that accident and place the reactor(s) in a cold shutdown condition; or
    b. "Environmentally induced failures caused by a leak or rupture of the pipe which would not of itself result in protective action but does disable protection functions. In this regard, a loss of redundancy is permitted but a loss of function is not permitted. For such situations plant shutdown is required."

12. Assurance should be provided tha the control room will be habitable and its equipment functional after a steam line or feedwater line

break or that the capability for shutdown and cooldown of the unit(s) will be available in another habitable area.

13. Environmental qualification should be demonstrated by test for that electrical equipment required to function in the steam-air environment resulting from a high energy fluid line break. The information required for our review should include the following:

    a. Identification of all electrical equipment necessary to meet requirements of 11 above. The time after the accident in which they are required to operate should be given.

    b. The test conditions and the results of test data showing that the systems will perform their intended function in the environment resulting from the postulated accident and time interval of the accident. Environmental conditions used for the tests should be selected from a conservative evaluation of accident conditions.

    c. The results of a study of steam systems identifying locations where barriers will be required to prevent steam jet impingement from disabling a protection system. The design criteria for the barriers should be stated and the capability of the equipment to survive within the protected environment should be described.

    d. An evaluation of the capability for safety related electrical equipment in the control room to function in the environment that may exist following a pipe break accident should be provided. Environmental conditions used for the evaluation should be selected from conservative calculations of accident conditions.

e. An evaluation to assure that the onsite power distribution system and onsite sources (diesels and batteries) will remain operable throughout the event.

14. Design diagrams and drawings of the steam and feedwater lines including branch lines showing the routine from containment to the turbine building should be provided. The drawings should show elevations and include the location relative to the piping runs of safety related equipment including ventilation equipment, intakes, and ducts.

16. A description should be provided of the quality control and inspection programs that will be required or have been utilized for piping systems outside containment.

17. If leak detection equipment is to be used in the proposed modifications, a discussion of its capabilities should be provided.

18. A summary should be provided of the emergency procedures that would be followed after a pipe break accident, including the automatic and manual operations required to place the reactor unit(s) in a

cold shutdown condition. The estimated times following the accident for all equipment and personnel operational actions should be included in the procedure summary.

19. A description should be provided of the seismic and quality classification of the high energy fluid piping systems including the steam and feedwater piping that run near structures, systems, or components important to safety.

20. A description should be provided of the assumptions, methods, and results of analyses, including steam generator blowdown, used to calculate the pressure and temperature transients in compartments, pipe tunnels, intermediate buildings, and the turbine building following a pipe rupture in these areas. The equipment assumed to function in the analyses should be identified and the capability of systems required to function to meet a single active component failure should be described.

21. A description should be provided of the methods or analyses performed to demonstrate that there will be no adverse effects on the primary and/or secondary containment structures due to a pipe rupture outside these structures.

Footnotes

[1] The internal fluid energy level associated with the pipe break reaction may take into account any line restrictions (e.g., flow limiter) between the pressure source and break location, and the effects of either single-ended or double-ended flow conditions, as applicable. The energy level in a whipping pipe may be considered as insufficient to rupture an impacted pipe of equal or greater nominal pipe size and equal or heavier wall thickness.

[2] Piping is a pressure retaining component consisting of straight or curved pipe and pipe fittings (e.g., elbows, tees, and reducers).

[3] A piping run interconnects components such as pressure vessels, pumps, and rigidly fixed valves that may act to restrain pipe movement beyond that required for design thermal displacement. A branch run differs from a piping run only in that it originates at a piping intersection, as a branch of the main pipe run.

[4] Operational plant conditions include normal reactor operation, upset conditions (e.g., anticipated operational occurrences) and testing conditions.

[5] S_m is the design stress intensity as specified in Section III of the ASME Boiler and Pressure Vessel Code, "Nuclear Plant Components."

[6] U is the cumulative usage factor as specified in Section III of the ASME Boiler and Pressure Vessel Code, "Nuclear Power Plant Components."

[7] S_h is the stress calculated by the rules of NC-3600 and ND-3600 for Class 2 and 3 components, respectively, of the ASME Code Section III Winter 1972 Addenda.

S_A is the allowable stress range for expansion stress calculated by the rules of NC-3600 of the ASME Code, Section III, or the USA Standard Code for Pressure Piping, ANSI B31.1.0-1967.

[8] Longitudinal breaks are parallel to the pipe axis and oriented at any point around the pipe circumference. The break area is equal to the effective cross-sectional flow area upstream of the break location. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the direction normal to the pipe axis.

[9] Circumferential breaks are perpendicular to the pipe axis, and the break area is equivalent to the internal cross-sectional area of the ruptured pipe. Dynamic forces resulting from such breaks are assumed to separate the piping axially, and cause shipping in any direction normal to the pipe axis.