August 29, 1996

Mr. William R. McCollum
Site Vice President
Catawba Nuclear Station
Duke Power Company
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SUBJECT: ISSUANCE OF AMENDMENTS - CATAWBA NUCLEAR STATION, UNIT 1 (TAC NO. M90566)

Dear Mr. McCollum:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 151 to Facility Operating License NPF-35 for the Catawba Nuclear Station, Unit 1. The amendment consists of changes to the Technical Specifications (TS) in response to your application dated September 30, 1994, as supplemented September 18, 1995, January 19, March 15, May 16, and August 27, 1996.

The amendment revises the TS to reflect the new setpoints, operational parameters, and approved analysis methodologies associated with replacement of the Unit 1 steam generators. The amendment also deletes references to steam generator tube repair methods, which will no longer be applicable after the replacement, and clarifies initial surveillances.

A copy of the related Safety Evaluation is also enclosed. A Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,

Original signed by:

Peter S. Tam, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-413

Enclosures:
1. Amendment No. 151 to NPF-35
2. Safety Evaluation

cc w/encl: See next page

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*SEE PREVIOUS CONCURRENCE

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DATE	8/28/96	8/28/96	07/15/96	08/22/96
COPY	YES NO	YES NO	YES NO	YES NO

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 29, 1996

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Site Vice President
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Duke Power Company
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

DUKE POWER COMPANY

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

SALUDA RIVER ELECTRIC COOPERATIVE, INC.

DOCKET NO. 50-413

CATAWBA NUCLEAR STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 151
License No. NPF-35

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Catawba Nuclear Station, Unit 1 (the facility) Facility Operating License No. NPF-35 filed by the Duke Power Company, acting for itself, North Carolina Electric Membership Corporation and Saluda River Electric Cooperative, Inc. (licensees), dated September 30, 1994, as supplemented September 18, 1995, January 19, March 15, May 16, and August 27, 1996, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

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2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 2.C.(2) of Facility Operating License No. NPF-35 is hereby amended to read as follows:

   Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 151, which is attached hereto, is hereby incorporated into this license. Duke Power Company shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Herbert N. Berkow

Herbert N. Berkow, Director
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification
Changes

Date of Issuance: August 29, 1996

ATTACHMENT TO LICENSE AMENDMENT NO. 151

FACILITY OPERATING LICENSE NO. NPF-35

DOCKET NO. 50-413

Replace the following pages of the Technical Specifications with the enclosed pages. The revised pages are identified by amendment number and contain vertical lines indicating the areas of change.

Remove Pages	Insert Pages
VII	VII
VIII	VIII
2-5	2-5
2-8	2-8
2-10	2-10
3/4 3-31	3/4 3-31
3/4 3-32	3/4 3-32
3/4 3-33	3/4 3-33
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3/4 4-14	3/4 4-14
3/4 4-15	3/4 4-15
3/4 4-16	3/4 4-16
3/4 4-17	3/4 4-17
3/4 4-18	3/4 4-18
3/4 4-19	3/4 4-19
3/4 4-20	3/4 4-20
3/4 4-21	3/4 4-21
3/4 4-22	3/4 4-22
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REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
12. Steam Generator Water		
Level Low-Low	≥ 10.7% of narrow range span	≥ 9% of narrow range span
13. Undervoltage - Reactor Coolant Pumps	≥ 77% of bus voltage (5082 volts) with a 0.7s response time	≥ 76% (5016 volts)
14. Underfrequency - Reactor Coolant Pumps	≥ 56.4 Hz with a 0.2s response time	≥ 55.9 Hz
15. Turbine Trip		
a. Stop Valve EH Pressure Low	≥ 550 psig	≥ 500 psig
b. Turbine Stop Valve Closure	≥ 1% open	≥ 1% open
16. Safety Injection Input from ESF	N.A.	N.A.

NOTE 1: (Continued)

T' $\leq$ 585.1°F (Nominal T_{avg} allowed by Safety Analysis);

K_3 = Overtemperature ΔT reactor trip depressurization setpoint penalty coefficient as presented in the Core Operating Limits Report;

P = Pressurizer pressure, psig;

P' = 2235 psig (Nominal RCS operating pressure);

S = Laplace transform operator, s^{-1};

and f_1 (ΔI) is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers; with gains to be selected based on measured instrument response during plant STARTUP tests such that:

(i) For $q_t - q_b$ between the "positive" and "negative" f_1 (ΔI) breakpoints as presented in the Core Operating Limits Report;

f_1 (ΔI) = 0, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(ii) For each percent ΔI that the magnitude of $q_t - q_b$ is more negative than the f_1 (ΔI) "negative" breakpoint presented in the Core Operating Limits Report, the ΔT Trip Setpoint shall be automatically reduced by the f_1 (ΔI) "negative" slope presented in the Core Operating Limits Report; and

(iii) For each percent ΔI that the magnitude of $q_t - q_b$ is more positive than the f_1 (ΔI) "positive" breakpoint presented in the Core Operating Limits Report, the ΔT Trip Setpoint shall be automatically reduced by the f_1 (ΔI) "positive" slope presented in the Core Operating Limits Report.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 4.5% of Rated Thermal Power.

NOTE 3: (Continued)

K_6 = Overpower ΔT reactor trip heatup setpoint penalty coefficient as presented in the Core Operating Limits Report for $T > T''$ and $K_6 = 0$ for $T \leq T''$,

T = As defined in Note 1,

T'' = Indicated T_{avg} at RATED THERMAL POWER (Calibration temperature for ΔT instrumentation, $\leq 585.1°F$),

S = As defined in Note 1,

and $f_2(\Delta I)$ is a function of the indicated differences between top and bottom detectors of the power-range neutron ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between the "positive" and "negative" $f_2(\Delta I)$ breakpoints as presented in the Core Operating Limits Report; $f_2(\Delta I) = 0$, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(ii) for each percent ΔI that the magnitude of $q_t - q_b$ is more negative than the $f_2(\Delta I)$ "negative" breakpoint presented in the Core Operating Limits Report, the ΔT Trip Setpoint shall be automatically reduced by the $f_2(\Delta I)$ "negative" slope presented in the Core Operating Limits Report; and

(iii) for each percent ΔI that the magnitude of $q_t - q_b$ is more positive than the $f_2(\Delta I)$ "positive" breakpoint presented in the Core Operating Limits Report the ΔT Trip Setpoint shall be automatically reduced by the $f_2(\Delta I)$ "positive" slope presented in the Core Operating Limits Report.

NOTE 4: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 3.0% of Rated Thermal Power.

TABLE 3.3-4 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
4. Steam Line Isolation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 3 psig	≤ 3.2 psig
d. Steam Line Pressure - Low	≥ 775 psig	≥ 744 psig
e. Steam Line Pressure-Negative Rate - High	≤ 100 psi	≤ 122.8 psi**
5. Feedwater Isolation		
a. Automatic Actuation Logic Actuation Relays	N.A.	N.A.
b. Steam Generator Water Level-High-High (P-14)	≤ 83.9% of narrow range instrument span	≤ 85.6% of narrow range instrument span
c. T_{avg}-Low	≥ 564°F	≥ 561°F
d. Doghouse Water Level-High	11 inches above 577' floor level	12 inches above 577' floor level
e. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

TABLE 3.3-4 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
6. Turbine Trip		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Steam Generator Water Level-High-High (P-14)	≤ 83.9% of narrow range instrument span	≤ 85.6% of narrow range instrument span
d. Trip of All Main Feedwater Pumps	N.A.	N.A.
e. Reactor Trip (P-4)	N.A.	N.A.
f. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
7. Containment Pressure Control System		
a. Start Permissive	≤ 0.4 psid	≤ 0.45 psid
b. Termination	≥ 0.3 psid	≥ 0.25 psid
8. Auxiliary Feedwater		
a. Manual Initiation	N.A	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.

TABLE 3.3-4 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
8. Auxiliary Feedwater (Continued)		
c. Steam Generator Water Level - Low-Low	≥ 10.7% of narrow range span	≥ 9% of narrow range span
d. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
e. Loss-of-Offsite Power	≥ 3500 V	≥ 3242 V
f. Trip of All Main Feedwater Pumps	N.A.	N.A.
g. Auxiliary Feedwater Suction Pressure-Low		
1) CAPS 5220, 5221, 5222	≥ 10.5 psig	≥ 9.5 psig
2) CAPS 5230, 5231, 5232	≥ 6.2 psig	≥ 5.2 psig
9. Containment Sump Recirculation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Refueling Water Storage Tank Level-Low Coincident With Safety Injection	≥ 177.15 inches	≥ 162.4 inches
	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

SURVEILLANCE REQUIREMENTS (Continued)

1) All nonplugged tubes that previously had detectable wall penetrations (greater than 20%),

2) Tubes in those areas where experience has indicated potential problems, and

3) A tube inspection (pursuant to Specification 4.4.5.4a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 4.4-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1) The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found, and

2) The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

4.4.5.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection after steam generator replacement shall be performed after at least 6 Effective Full Power Months but within 24 calendar months of initial criticality after steam generator replacement. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months;

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-2 at 40-month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.4.5.3a.; the interval may then be extended to a maximum of once per 40 months; and

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

   1) Reactor-to-secondary tubes leak (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2, or

   2) A seismic occurrence greater than the Operating Basis Earthquake, or

   3) A loss-of-coolant accident requiring actuation of the Engineered Safety Features, or

   4) A main steam line or feedwater line break.

4.4.5.4 Acceptance Criteria

a. As used in this specification:

1) Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube wall thickness, if detectable, may be considered as imperfections;

2) Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube;

3) Degraded Tube means a tube containing imperfections greater than or equal to 20% of the nominal tube wall thickness caused by degradation;

4) % Degradation means the percentage of the tube wall thickness affected or removed by degradation;

5) Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective;

6) Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging. The plugging limit is equal to 40% of the nominal tube wall thickness.

7) Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 4.4.5.3c., above;

8) Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg;

9) Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

SURVEILLANCE REQUIREMENTS (Continued)

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug all tubes exceeding the plugging limit and all tubes containing through-wall cracks) required by Table 4.4-2.

4.4.5.5 Reports

a. Within 15 days following the completion of each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2;

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission in a Special Report pursuant to Specification 6.9.2 within 12 months following the completion of the inspection. This Special Report shall include:

   1) Number and extent of tubes inspected,

   2) Location and percent of wall-thickness penetration for each indication of an imperfection, and

   3) Identification of tubes plugged.

c. Results of steam generator tube inspections, which fall into Category C-3, shall be reported in a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days and prior to resumption of plant operation. This report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

Table 4.4-1

MINIMUM NUMBER OF STEAM GENERATORS TO BE INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	No	Yes
No. of Steam Generators per Unit	Four	Four
First Inservice Inspection after Steam Generator Replacement	All	Two
Second & Subsequent Inservice Inspections	One[1]	One[2]

TABLE NOTATIONS

1 The inservice inspection may be limited to one steam generator on a rotating schedule encompassing 3 N % of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

2 Each of the other two steam generators not inspected after steam generator replacement during the first inservice inspections shall be inspected during the second and third inspections. The fourth and subsequent inspections shall follow the instructions described in 1 above.

TABLE 4.4-2

STEAM GENERATOR TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G.	C-1	None	N.A.	N.A.	N.A.	N.A.
	C-2	Plug defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N.A.	N.A.
			C-2	Plug deflective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N.A.	N.A.
	C-3	Inspect all tubes in this S.G., plug defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to §50.72(b)(2) of 10 CFR Part 50.	All other S.G.s are C-1	None	N.A.	N.A.
			Some S.G.s C-2 but no additional S.G. are C-3	Perform action for C-2 result of second sample	N.A.	N.A.
			Additional S.G.is C-3	Inspect all tubes in each S.G. and plug defective tubes. Notification to NRC pursuant to §50.72 (b)(2) of 10 CFR 50.	N.A.	N.A.

S = 3 (N/n)% Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.6.1 The following Reactor Coolant System Leakage Detection Systems shall be OPERABLE:

a. The Containment Atmosphere Gaseous Radioactivity Monitoring System,

b. The Containment Floor and Equipment Sump Level and Flow Monitoring Subsystem, and

c. Either the Containment Ventilation Unit Condensate Drain Tank Level Monitoring Subsystem or the Containment Atmosphere Particulate Radioactivity Monitoring System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only two of the above required Leakage Detection Systems OPERABLE, operation may continue for up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once per 24 hours when the required Gaseous or Particulate Radioactivity Monitoring System is inoperable; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 The Leakage Detection Systems shall be demonstrated OPERABLE by:

a. Containment Atmosphere Gaseous and Particulate Monitoring System-performance of CHANNEL CHECK, CHANNEL CALIBRATION, and ANALOG CHANNEL OPERATIONAL TEST at the frequencies specified in Table 4.3-3,

b. Containment Floor and Equipment Sump Level and Flow Monitoring Subsystem-performance of CHANNEL CALIBRATION at least once per 18 months, and

c. Containment Ventilation Unit Condensate Drain Tank Level Monitoring Subsystem-performance of CHANNEL CALIBRATION at least once per 18 months.

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 gpm UNIDENTIFIED LEAKAGE,

c. 0.4 gpm total reactor-to-secondary leakage through all steam generators and 150 gallons per day through any one steam generator,

d. 10 gpm IDENTIFIED LEAKAGE from the Reactor Coolant System,

e. 40 gpm CONTROLLED LEAKAGE at a Reactor Coolant System pressure of 2235 ± 20 psig, and

f. 1 gpm leakage at a Reactor Coolant System pressure of 2235 ± 20 psig from any Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE and leakage from Reactor Coolant System Pressure Isolation Valves, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere gaseous or particulate radioactivity monitor at least once per 12 hours;

b. Monitoring the containment floor and equipment sumps inventory and discharge at least once per 12 hours;

c. Measurement of the CONTROLLED LEAKAGE to the reactor coolant pump seals when the Reactor Coolant System pressure is 2235 ± 20 psig at least once per 31 days. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4;

d. Performance of a Reactor Coolant System water inventory balance at least once per 72 hours; and

e. Monitoring the reactor head flange leakoff at least once per 24 hours.

4.4.6.2.2 Each Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1 shall be demonstrated OPERABLE by verifying leakage to be within its limit:

a. At least once per 18 months,

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

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

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

The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4.

TABLE 3.4-1

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

VALVE NUMBER	FUNCTION
NI59	Accumulator Discharge
NI60	Accumulator Discharge
NI70	Accumulator Discharge
NI71	Accumulator Discharge
NI81	Accumualtor Discharge
NI82	Accumulator Discharge
NI93	Accumulator Discharge
NI94	Accumulator Discharge
NI124	Safety Injection (Hot Leg)
NI125	Residual Heat Removal (Hot Leg)
NI126	Safety Injection (Hot Leg)
NI128	Safety Injection (Hot Leg)
NI129	Residual Heat Removal (Hot Leg)
NI134	Safety Injection (Hot Leg)
NI156	Safety Injection (Hot Leg)
NI157	Safety Injection (Hot Leg)
NI159	Safety Injection (Hot Leg)
NI160	Safety Injection (Hot Leg)
NI165	Safety Injection/Residual Heat Removal (Cold Leg)
NI167	Safety Injection/Residual Heat Removal (Cold Leg)
NI169	Safety Injection/Residual Heat Removal (Cold Leg)
NI171	Safety Injection/Residual Heat Removal (Cold Leg)
NI175	Safety Injection/Residual Heat Removal (Cold Leg)
NI176	Safety Injection/Residual Heat Removal (Cold Leg)
NI180	Safety Injection/Residual Heat Removal (Cold Leg)
NI181	Safety Injection/Residual Heat Removal (Cold Leg)

TABLE 3.4-1 (Continued)

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

VALVE NUMBER	FUNCTION
ND1B*#	Residual Heat Removal
ND2A*#	Residual Heat Removal
ND36B*#	Residual Heat Removal
ND37A*#	Residual Heat Removal

*Testing per Specification 4.4.6.2.2d. not applicable due to positive indication of valve position in Control Room.

#1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

3/4.4.7 CHEMISTRY

LIMITING CONDITION FOR OPERATION

3.4.7 The Reactor Coolant System chemistry shall be maintained within the limits specified in Table 3.4-2.

APPLICABILITY: At all times.

ACTION:

MODES 1, 2, 3, and 4:

a. With any one or more chemistry parameter in excess of its Steady-State Limit but within its Transient Limit, restore the parameter to within its Steady-State Limit within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

b. With any one or more chemistry parameter in excess of its Transient Limit, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

At All Other Times:

With the concentration of either chloride or fluoride in the Reactor Coolant System in excess of its Steady-State Limit for more than 24 hours or in excess of its Transient Limit, reduce the pressurizer pressure to less than or equal to 500 psig, if applicable, and perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operation prior to increasing the pressurizer pressure above 500 psig or prior to proceeding to MODE 4.

SURVEILLANCE REQUIREMENTS

4.4.7 The Reactor Coolant System chemistry shall be determined to be within the limits by analysis of those parameters at the frequencies specified in Table 4.4-3.

TABLE 3.4-2

REACTOR COOLANT SYSTEM

CHEMISTRY LIMITS

PARAMETER	STEADY-STATE LIMIT	TRANSIENT LIMIT
Dissolved Oxygen*	≤ 0.10 ppm	≤ 1.00 ppm
Chloride	≤ 0.15 ppm	≤ 1.50 ppm
Fluoride	≤ 0.15 ppm	≤ 1.50 ppm

*Limit not applicable with T_{avg} less than or equal to 250°F.

TABLE 4.4-3

REACTOR COOLANT SYSTEM

CHEMISTRY LIMITS SURVEILLANCE REQUIREMENTS

PARAMETER	SAMPLE AND ANALYSIS FREQUENCY
Dissolved Oxygen*	At least once per 72 hours
Chloride	At least once per 72 hours
Fluoride	At least once per 72 hours

*Not required with T_{avg} less than or equal to 250°F

3/4.4.8 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.8 The specific activity of the reactor coolant shall be limited to:

a. Less than or equal to 1 microCurie per gram DOSE EQUIVALENT I-131, and

b. Less than or equal to $100/\bar{E}$ microCuries per gram of gross specific activity.

APPLICABILITY: MODES 1, 2, 3, 4, and 5.

ACTION:

MODES 1, 2 and 3*:

a. With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in at least HOT STANDBY with T_{avg} less than 500°F within 6 hours;

b. With the gross specific activity of the reactor coolant greater than $100/\bar{E}$ microCuries per gram of gross radioactivity, be in at least HOT STANDBY with T_{avg} less than 500°F within 6 hours; and

c. The provisions of Specification 3.0.4 are not applicable.

MODES 1, 2, 3, 4, and 5:

With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 or greater than $100/\bar{E}$ microcuries per gram, perform the sampling and analysis requirements of Item 4.a) of Table 4.4-4 until the specific activity of the reactor coolant is restored to within its limits.

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the reactor coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

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*With T_{avg} greater than or equal to 500°F.

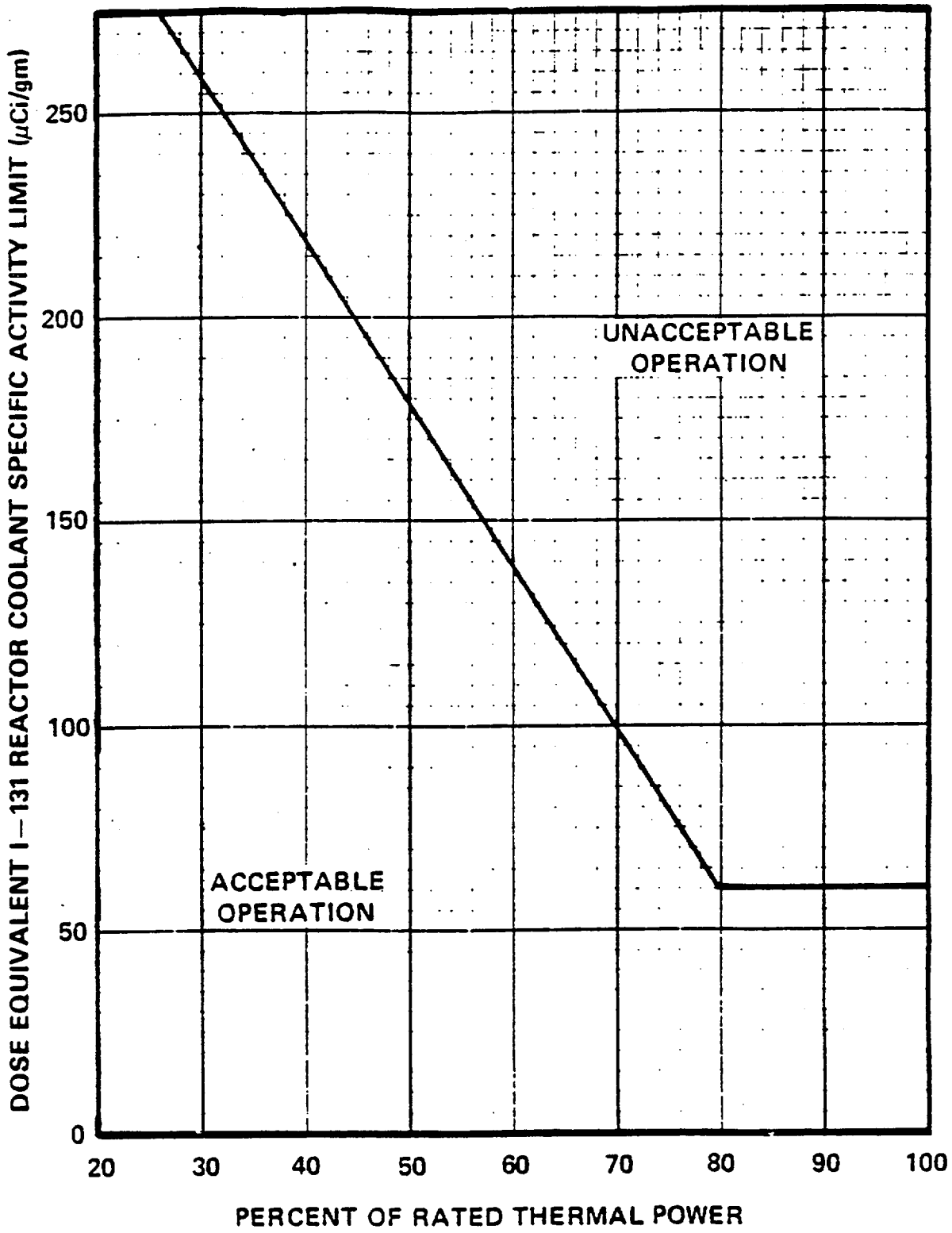


FIGURE 3.4-1

DOSE EQUIVALENT I-131 REACTOR COOLANT SPECIFIC ACTIVITY LIMIT VERSUS PERCENT OF RATED THERMAL POWER WITH THE REACTOR COOLANT SPECIFIC ACTIVITY > 1 μCi/gram DOSE EQUIVALENT I-131

TABLE 4.4-4

REACTOR COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED
1. Gross Radioactivity Determination**	At least once per 72 hours	1, 2, 3, 4
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1
3. Radiochemical for $\bar{E}$ Determination***	1 per 6 months*	1
4. Isotopic Analysis for Iodine Including I-131, I-133, and I-135	a) Once per 4 hours, whenever the specific activity exceeds 1 μCi/gram DOSE EQUIVALENT I-131 or 100/$\bar{E}$ μCi/gram of gross radioactivity, and	1#, 2#, 3#, 4#, 5#
	b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15% of the RATED THERMAL POWER within a 1-hour period.	1, 2, 3

TABLE 4.4-4 (Continued)

TABLE NOTATIONS

Until the specific activity of the Reactor Coolant System is restored within its limits.

* Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

** A gross radioactivity analysis shall consist of the quantitative measurement of the total specific activity of the reactor coolant except for radionuclides with half-lives less than 10 minutes and all radioiodines. The total specific activity shall be the sum of the beta-gamma activity in the sample within 2 hours after the sample is taken and extrapolated back to when the sample was taken. Determination of the contributors to the gross specific activity shall be based upon those energy peaks identifiable with a 95% confidence level. The latest available data may be used for pure beta-emitting radionuclides.

*** A radiochemical analysis for $\bar{E}$ shall consist of the quantitative measurement of the specific activity for each radionuclide, except for radionuclides with half-lives less than 10 minutes and all radioiodines, which is identified in the reactor coolant. The specific activities for these individual radionuclides shall be used in the determination of $\bar{E}$ for the reactor coolant sample. Determination of the contributors to $\bar{E}$ shall be based upon those energy peaks identifiable with a 95% confidence level.

3/4.4.9 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.9.1 The Reactor Coolant System (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown on Figures 3.4-2 and 3.4-3 during heatup, cooldown, criticality, and inservice leak and hydrostatic testing with:

a. A maximum heatup of 60°F in any 1-hour period,

b. A maximum cooldown of 100°F in any 1-hour period, and

c. A maximum temperature change of less than or equal to 10°F in any 1-hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves.

APPLICABILITY: At all times.

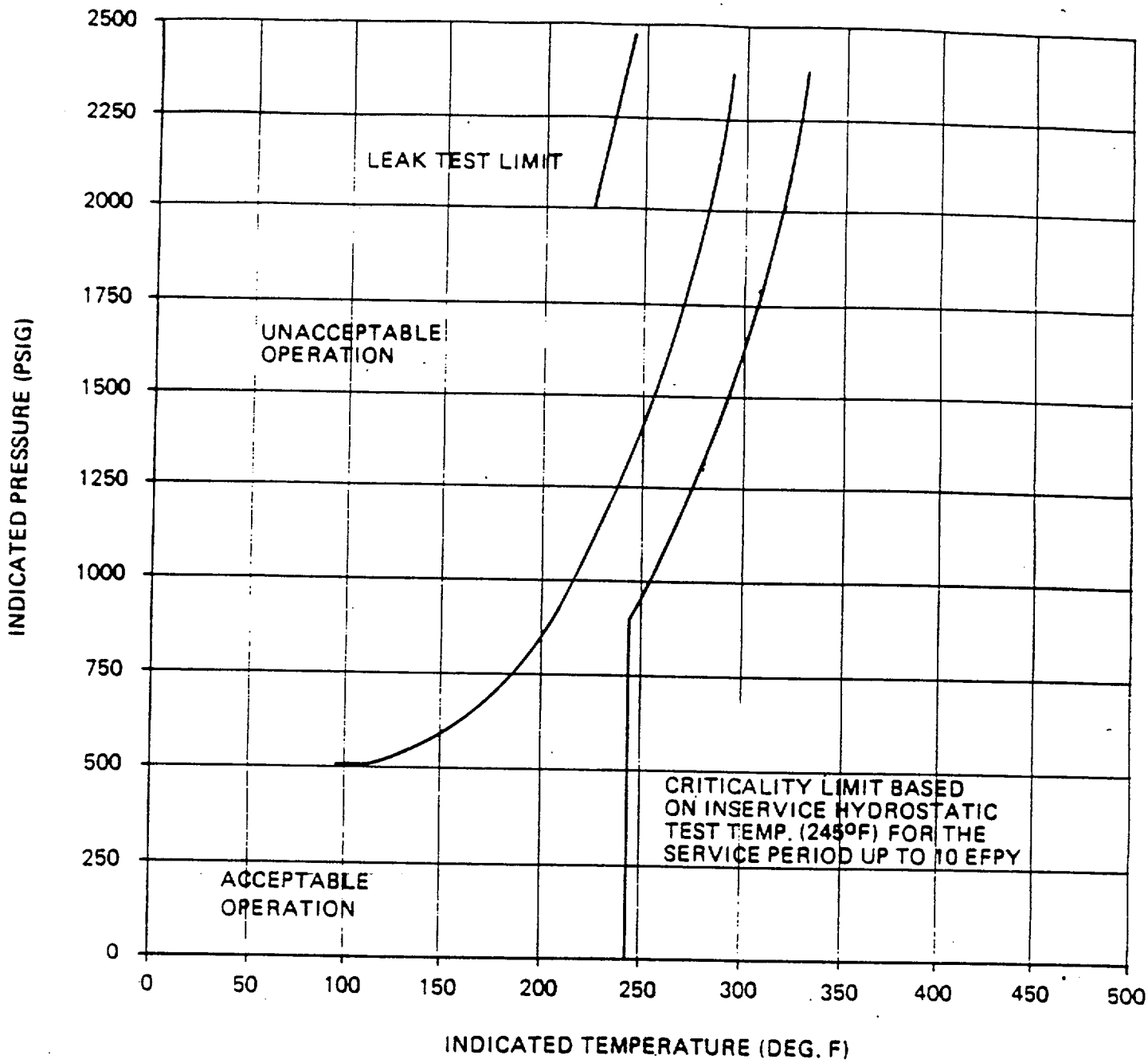
ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limit within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the T_{avg} and pressure to less than 200°F and 500 psig, respectively, within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.9.1.1 The Reactor Coolant System temperature and pressure shall be determined to be within the limits at least once per 30 minutes during system heatup, cooldown, and inservice leak and hydrostatic testing operations.

4.4.9.1.2 The reactor vessel material irradiation surveillance specimens shall be removed and examined, to determine changes in material properties, as required by 10 CFR Part 50, Appendix H in accordance with the schedule in Table 4.4-5. The results of these examinations shall be used to update Figures 3.4-2 and 3.4-3.

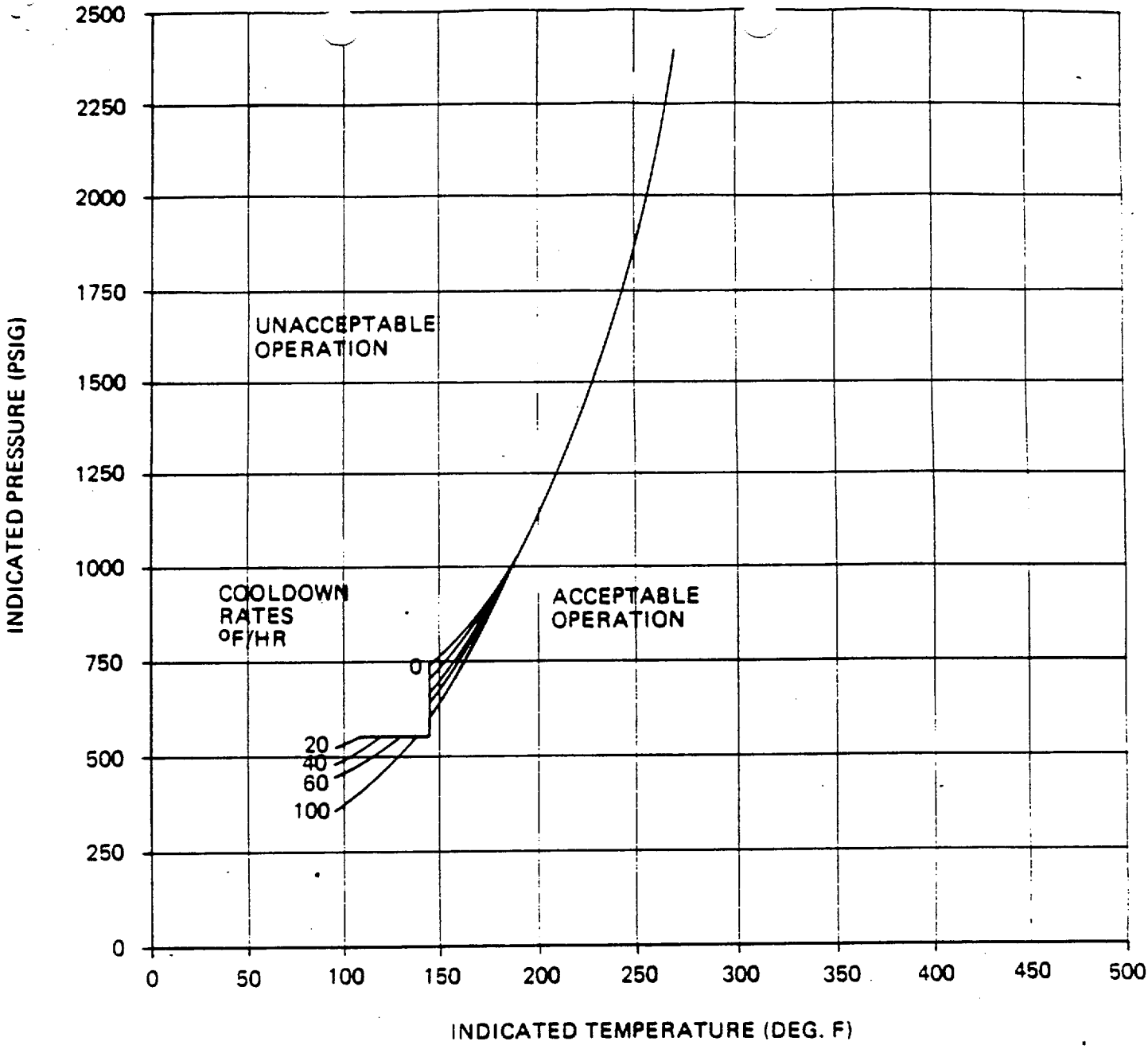


CURVE APPLICABLE FOR HEATUP RATES UP TO 60°F/HR FOR THE SERVICE PERIOD UP TO 10 EFPY CONTAINS MARGIN OF 10°F AND 60 PSIG FOR POSSIBLE INSTRUMENT ERRORS.

MATERIAL BASIS
CONTROLLING MATERIAL– UNIT 2 INTERMEDIATE SHELL PLATE B8606–2
COPPER CONTENT–0.07wt%
NICKEL CONTENT– 0.61 wt %
RT_{NDT} INITIAL–33°F
RT_{NDT} AFTER 10 EFPY 1/4T, 104°F
3/4T, 92°F

FIGURE 3.4-2

REACTOR COOLANT SYSTEM HEATUP LIMITATIONS
APPLICABLE FOR THE FIRST 10 EFPY



CURVE APPLICABLE FOR COOLDOWN RATES UP TO 100°F/HR FOR THE SERVICE PERIOD UP TO 10 EFPY CONTAINS MARGIN OF 10°F AND 60 PSIG FOR POSSIBLE INSTRUMENT ERRORS.

MATERIAL BASIS
CONTROLLING MATERIAL – UNIT 2 INTERMEDIATE SHELL PLATE B8606-2
COPPER CONTENT – 0.07wt%
NICKEL CONTENT – 0.61 wt%
RT_{NDT} INITIAL – 33°F
RT_{NDT} AFTER 10 EFPY 1/4T, 104°F
3/4T, 92°F

FIGURE 3.4-3

REACTOR COOLANT SYSTEM COOLDOWN LIMITATIONS - APPLICABLE FOR THE FIRST 10 EFPY

TABLE 4.4-5

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM - WITHDRAWAL SCHEDULE

CAPSULE NUMBER	VESSEL LOCATION	LEAD FACTOR	WITHDRAWN TIME (EFPY)
U	58.5°	3.85	Standby
V	61°	3.65	9
W	121.5°	3.85	Standby
X	238.5°	3.85	Standby
Y	241°	3.65	5
Z	301.5°	3.85	First Refueling

PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.9.2 The pressurizer temperature shall be limited to:

a. A maximum heatup of 100°F in any 1-hour period, and

b. A maximum cooldown of 200°F in any 1-hour period.

APPLICABILITY: At all times.

ACTION:

With the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the pressurizer pressure to less than 500 psig within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.9.2 The pressurizer temperatures shall be determined to be within the limits at least once per 30 minutes during system heatup or cooldown.

OVERPRESSURE PROTECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.9.3 At least one of the following Overpressure Protection Systems shall be OPERABLE:

a. Two power operated relief valves (PORVs) with a lift setting of less than or equal to 450 psig, or

b. The Reactor Coolant System depressurized with a Reactor Coolant System vent of greater than or equal to 4.5 square inches.

APPLICABILITY: MODE 4 when the temperature of any Reactor Coolant System cold leg is less than or equal to 285°F, MODE 5 and MODE 6 when the head is on the reactor vessel.

ACTION:

a. With one PORV inoperable in MODE 4, restore the inoperable PORV to OPERABLE status within 7 days or complete depressurization and venting of the Reactor Coolant System through at least a 4.5 square inch vent within the next 8 hours.

b. With one PORV inoperable in MODES 5 or 6, restore the inoperable PORV to OPERABLE status within 24 hours or complete depressurization and venting of the Reactor Coolant System through at least a 4.5 square inch vent within the next 8 hours.

c. With both PORVs inoperable, complete depressurization and venting of the Reactor Coolant System through at least a 4.5 square inch vent within 8 hours.

d. In the event either the PORVs or the Reactor Coolant System vent(s) are used to mitigate a Reactor Coolant System pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or Reactor Coolant System vent(s) on the transient, and any corrective action necessary to prevent recurrence.

e. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.9.3.1 Each PORV shall be demonstrated OPERABLE by:

a. Performance of an ANALOG CHANNEL OPERATIONAL TEST on the PORV actuation channel, but excluding valve operation, at least once per 31 days;

b. Performance of a CHANNEL CALIBRATION on the PORV actuation channel at least once per 18 months; and

c. Verifying the PORV isolation valve is open at least once per 72 hours when the PORV is being used for overpressure protection.

4.4.9.3.2 The Reactor Coolant System vent(s) shall be verified to be open at least once per 12 hours* when the vent(s) is being used for overpressure protection.

*Except when the vent pathway is provided with a valve which is locked, sealed, or otherwise secured in the open position, then verify these valves open at least once per 31 days.

3/4.4.10 STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.4.10 The structural integrity of ASME Code Class 1, 2, and 3 components shall be maintained in accordance with Specification 4.4.10.

APPLICABILITY: All MODES.

ACTION:

a. With the structural integrity of any ASME Code Class 1 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature more than 50°F above the minimum temperature required by NDT considerations.

b. With the structural integrity of any ASME Code Class 2 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature above 200°F.

c. With the structural integrity of any ASME Code Class 3 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) from service.

SURVEILLANCE REQUIREMENTS

4.4.10 In addition to the requirements of Specification 4.0.5, each reactor coolant pump flywheel shall be inspected per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975.

3/4.4.11 REACTOR COOLANT SYSTEM VENTS

LIMITING CONDITION FOR OPERATION

3.4.11 At least one Reactor Coolant System vent path consisting of at least two valves in series powered from emergency buses shall be OPERABLE and closed* at each of the following locations:

a. Reactor Vessel Head

b. Pressurizer steam space

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one of the above Reactor Coolant System vent paths inoperable, STARTUP and/or POWER OPERATION may continue provided the inoperable vent path is maintained closed with power removed from the valve actuator of all the valves in the inoperable vent path; restore the inoperable vent path to OPERABLE status within 30 days, or, be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With both of the above Reactor Coolant System vent paths inoperable, maintain the inoperable vent paths closed with power removed from the valve actuators of all the valves in the inoperable vent paths, and restore at least one of the vent paths to OPERABLE status within 72 hours or be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.11 Each Reactor Coolant System vent path shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying all manual isolation valves in each vent path are locked in the open position, and

b. Cycling each valve in the vent path through at least one complete cycle of full travel from the control room during COLD SHUTDOWN or REFUELING.

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*For the plants using power operated relief valve (PORV) as a vent path, PORV block is not required to be closed if the PORV is operable.

CONTROL ROD ASSEMBLIES

5.3.2 The core shall contain 53 full-length control rod assemblies. The full-length control rod assemblies shall contain a nominal 142 inches of absorber material of which 102 inches shall be 100% boron carbide and remaining 40-inch tip shall be 80% silver, 15% indium, and 5% cadmium.

All control rods shall be clad with stainless steel tubing.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The Reactor Coolant System is designed and shall be maintained:

a. In accordance with the Code requirements specified in Section 5.2 of the FSAR, with allowance for normal degradation pursuant to the applicable Surveillance Requirements,

b. For a pressure of 2485 psig, and

c. For a temperature of 650°F, except for the pressurizer which is 680°F.

VOLUME

5.4.2 The total water and steam volume of the Reactor Coolant System is 13,050 ± 100 cubic feet at a nominal T_{avg} of 525°F.

5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown in Figure 5.1-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1 a. The spent fuel storage racks are designed and shall be maintained with:

1) $k_{eff} \leq 0.95$ if fully flooded with unborated water as described in Section 9.1 of the FSAR; and

2) A nominal 13.5" center to center distance between fuel assemblies placed in the spent fuel storage racks.

b. The new fuel storage racks are designed and shall be maintained with:

1) $k_{eff} \leq 0.95$ if fully flooded with unborated water as described in Section 9.1 of the FSAR; and

2) $k_{eff} \leq 0.98$ if moderated by aqueous foam as described in Section 9.1 of the FSAR; and

CORE OPERATING LIMITS REPORT (Continued)

Insertion Limits, 3.2.1 - Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor.)

7. DPC-NF-2010A, "Duke Power Company McGuire Nuclear Station Catawba Nuclear Station Nuclear Physics Methodology for Reload Design," June 1985

   (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient, Specification 4.7.13.3 - Standby Makeup Pump Water Supply Boron Concentration, and Specification 3.9.1 - RCS and Refueling Canal Boron Concentration, and Specification 3.9.12 - Spent Fuel Pool Boron Concentration.)

8. DPC-NE-3002, Rev. 1, "FSAR Chapter 15 System Transient Analysis Methodology," SER dated December, 1995.

   (Methodology used in the system thermal-hydraulic analyses which determine the core operating limits)

9. DPC-NE-3000P, Rev. 1, "Thermal-Hydraulic Transient Analysis Methodology," SER dated December, 1995.

   (Modeling used in the system thermal-hydraulic analyses)

10. DPC-NE-1004A, "Design Methodology Using CASMO-3/Simulate-3P," November 1992.

    (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient.)

11. DPC-NE-2004P-A, "Duke Power Company McGuire and Catawba Nuclear Stations Core Thermal-Hydraulic Methodology using VIPRE-01," December 1991 (DPC Proprietary).

    (Methodology for Specifications 2.2.1 - Reactor Trip System Instrumentation Setpoints, 3.2.1 - Axial Flux Difference (AFD), and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor $F_{\Delta H}$ (X,Y).)

12. DPC-NE-2001P-A, Rev. 1, "Fuel Mechanical Reload Analysis Methodology for Mark-BW Fuel," October 1990 (DPC Proprietary).

    (Methodology for Specification 2.2.1 - Reactor Trip System Instrumentation Setpoints.)

13. DPC-NE-2005P-A, "Thermal Hydraulic Statistical Core Design Methodology," February 1995 (DPC Proprietary).

    (Methodology for Specification 2.2.1 - Reactor Trip System Instrumentation Setpoints, Specification 3.2.1 - Axial Flux Difference, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor)

RELIEF VALVES (Continued)

of PORVs to control reactor coolant system pressure except for limited periods where the PORV has been isolated due to excessive seat leakage and except for limited periods where the PORV and/or block valve is closed because of testing and is fully capable of being returned to its normal alignment at any time, provided that this evolution is covered by an approved procedure. This is a function that reduces challenges to the code safety valves for overpressurization events. 5) Manual control of a block valve to isolate a stuck-open PORV. Testing of the PORVs includes the emergency N_2 supply from the Cold Leg Accumulators. This test demonstrates that the valves in the supply line operate satisfactorily and that the nonsafety portion of the instrument air system is not necessary for proper PORV operation.

3/4.4.5 STEAM GENERATORS

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the Reactor Coolant System will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the limitation of steam generator tube leakage between the Reactor Coolant System and the Secondary Coolant System (reactor-to-secondary leakage = 150 gallons per day per steam generator).

STEAM GENERATORS (Continued)

Cracks having a reactor-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that reactor-to-secondary leakage of 150 gallons per day per steam generator can readily be detected. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and repaired.

Wastage-type defects are unlikely with proper chemistry treatment of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging will be required for all tubes with imperfections exceeding the plugging limit of 40% of the tube nominal wall thickness. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect wastage type degradation that has penetrated 20% of the original tube wall thickness.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be reported to the Commission pursuant to Specification 6.9.2 prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.6.1 LEAKAGE DETECTION SYSTEMS

The Leakage Detection Systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary. These Detection Systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 151 TO FACILITY OPERATING LICENSE NPF-35

DUKE POWER COMPANY, ET AL.

CATAWBA NUCLEAR STATION, UNIT 1

DOCKET NO. 50-413

1.0 INTRODUCTION

By letter dated September 30, 1994, as supplemented by letters dated September 18, 1995, January 19, March 15, May 16, and August 27, 1996, Duke Power Company, et al. (DPC, the licensee) requested changes to the Technical Specifications (TS) for the Catawba Nuclear Station, Unit 1. These changes are related to the replacement of the original Westinghouse Model "D" type preheat steam generators (SGs) with feedring steam generators designed by Babcock & Wilcox International. The May 16 and August 27, 1996, letters provided clarifying information that did not change the scope of the original application of September 30, 1994, and the initial proposed no significant hazards consideration.

The major design differences in the feedring steam generator with respect to the preheat design include the following:

- There are approximately 2,000 more tubes of a slightly smaller diameter.
- The tube bundle is about 8 feet taller.
- The SG liquid mass at full power is approximately 20,000 lbm greater.

The above steam generator design differences result in the following thermal-hydraulic changes:

- The total primary system volume is increased by about 10%.
- The effective tube bundle heat transfer area is increased by approximately 60%.
- The full power programmed T_{avg} for Catawba is reduced by about 6°F.

2.0 EVALUATION

The licensee stated that all the analyses were performed consistent with NRC-approved methodology. The following is a list of applicable Duke Power Company analysis methodology topical reports:

DPC-NE-3000-P, Revision 1, Thermal-Hydraulic Transient Analysis Methodology, Duke Power Company, Oconee, McGuire and Catawba Nuclear Stations. (Approved by letter, R. Martin to M. Tuckman, December 27, 1995)

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DPC-NE-3001-PA, Multidimensional Reactor Transients and Safety Analysis Physics Parameters Methodology, Duke Power Company, McGuire and Catawba Nuclear Stations, November 30, 1991.

DPC-NE-3002, FSAR Chapter 15 System Transient Analysis Methodology, Duke Power Company, McGuire and Catawba Nuclear Station. (Revision 1 approved by letter, R. Martin to M. Tuckman, December 28, 1995; Revision 2 approved by letter, R. Martin to M. Tuckman, April 26, 1996)

DPC-NE-3004-P, Mass and Energy Release and Containment Response Methodology, Duke Power Company, McGuire and Catawba Nuclear Stations. (Approved by letter, R. Martin to M. Tuckman, September 6, 1995)

In addition, the steam generator tube rupture and loss-of-coolant accident (LOCA) reanalyses relied upon the following vendor topical reports:

WCAP-10698-PA, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," Westinghouse Electric Corporation.

BAW-10168, Revision 3, "BWNT Loss-of-Coolant Accident Evaluation Model for Recirculating Steam Generator Plants," Babcock & Wilcox. (Approved by letter, M. Virgilio to J. H. Taylor, June 15, 1994)

BAW-10174A, Revision 1, "Mark-BW Reload LOCA Analysis for the McGuire and Catawba Units," Revision 1, Babcock & Wilcox.

DPC reevaluated each Final Safety Analysis Report (FSAR) transient and accident analysis to determine the effects of the steam generator replacement, and to ensure that thermal-hydraulic performance will not be degraded. The staff's review of DPC's reanalysis is delineated in Sections 2.1 through 2.3.

2.1 Design Basis Transients and Accidents

The following thermal-hydraulic system transients were reanalyzed by the licensee in order to ensure that the acceptance criteria continue to be met with the feedring steam generators. DPC stated that all analyses were performed consistent with NRC-approved methodology.

A. Mass and energy release for postulated loss-of-coolant accidents inside containment (UFSAR Section 6.2.1.3)

This event was analyzed to ensure that the peak containment pressure limit is not exceeded. Since the reactor coolant system (RCS) volume will be greater, the total mass released into containment will also be greater. In addition, during the depressurization of the RCS, the steam generators actually function as heat sources. Since the feedring steam generator full-power liquid mass is greater than that of the Model D steam generators, the total energy available for removal by the RCS is increased. Both of these effects have the potential to yield more severe mass and energy release results. The analysis was performed in accordance with the analytical model and methodology described in topical

report DPC-NE-3004. The peak lower containment pressure calculated for Catawba Unit 1 is 11.77 psig, which meets the 15 psig staff acceptance criterion stated in the Catawba Safety Evaluation Report (NUREG-0954).

B. Mass and energy release for postulated secondary system pipe ruptures inside containment (UFSAR Section 6.2.1.4)

This event was analyzed to ensure that the peak containment temperature limit is not exceeded. SG tube bundle uncovery is important since this initiates the release of superheated steam into the containment. Since the feedring steam generator design has tubes that are significantly taller than those in the original Model D generators, the potential exists for earlier bundle uncovery. The analysis was performed in accordance with the analytical model and methodology described in topical report DPC-NE-3004. The peak temperature in the break compartment is calculated to be 313 °F, which does not exceed the environmental qualification (EQ) limit of 340 °F and is therefore acceptable.

C. Feedwater system malfunction causing an increase in feedwater flow (UFSAR Section 15.1.2)

This event was analyzed to show that departure from nucleate boiling (DNB) does not occur. The transient involves an increase in core power resulting from overcooling by the secondary system. The impact of the increased heat transfer area of the feedring steam generator is investigated in this reanalysis. The reanalysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-NE-3002. The minimum DNB ratio is calculated as 1.86, which is well above the 1.55 design limit and is therefore acceptable.

D. Excessive increase in secondary steam flow (UFSAR Section 15.1.3)

This event was analyzed to show that DNB does not occur. The transient involves an increase in core power resulting from overcooling by the secondary system. The impact of the increased heat transfer area of the feedring steam generator is investigated in this reanalysis. The reanalysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-3002. The transient analysis results were found to be acceptable as the licensee found that the reactor reached an equilibrium condition that did not challenge the OPΔT or OTΔT reactor trip functions, which are designed to protect the core against DNB. Therefore, an explicit DNB ratio calculation was not performed.

E. Inadvertent opening of a steam generator relief or safety valve (UFSAR Section 15.1.4)

This event was reanalyzed to confirm that the transient response is bounded by the DNB calculation performed for steam system piping failure event. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000, DPC-NE-

3001 and DPC-NE-3002. The peak thermal power level reached was less than half of that resulting from the steam system piping failure event and thus the DNB ratio will be higher than that calculated for a steam system piping failure event. An explicit DNB ratio calculation was not performed.

F. Steam system piping failure (UFSAR Section 15.1.5)

This transient was reanalyzed to show that DNB does not occur. This transient involves an increase in core power resulting from overcooling by the secondary system. The impact of the increased heat transfer area of the feedring steam generator is investigated in this reanalysis. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-NE-3001. The minimum DNB ratio was calculated to be 1.78, which is well above the 1.45 design limit for this transient and therefore it is acceptable.

G. Turbine trip (UFSAR Section 15.2.3)

This event was analyzed to show that peak primary and secondary system pressures do not exceed the applicable limits. The increased heat transfer area of the feedring steam generator improves the ability of the secondary system to remove primary system heat and, therefore, potentially could result in a more severe secondary side pressurization. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-NE-3002. The calculated peak primary and secondary pressures are 2,674.3 and 1,285.7 psig, respectively. This is acceptable as the corresponding acceptance criteria are 2,733.5 psig (110% of 2,485 psig, design pressure of reactor coolant side) and 1,303.5 psig (110 % of 1,185 psig, design pressure of steam side).

H. Loss of non-emergency AC power to the station auxiliaries (UFSAR Section 15.2.6)

This event was reanalyzed to demonstrate the adequacy of natural circulation cooling in the modified reactor coolant loop configuration. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-NE-3002. The results of this analysis are acceptable as they show that, within 10 minutes of the loss of offsite power, a stable natural circulation flow rate of approximately 5% of the full-power flow value is established with a core ΔT of less that 30 °F. The results of the reanalysis indicate that this event is bounded by turbine trip.

I. Loss of normal feedwater flow (UFSAR Section 15.2.7)

This event was reanalyzed to confirm that the transient response is bounded by the turbine trip event. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-NE-3002. The position presented in DPC-NE-3002, that this transient is bounded by turbine trip, remains valid.

J. Feedwater system pipe break (UFSAR Section 15.2.8)

This event was analyzed to demonstrate the capability of the degraded secondary system to effectively cool the reactor core. While the increase in heat transfer area would tend to improve the transient results, other factors, such as the restrictor, necessitate the reanalysis. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-NE-3002. The adequacy of the long-term cooling capability is verified by the prevention of hot leg boiling. This was found to be acceptable as a minimum subcooling of 17.5 °F was reached during the overheating phase of the feedline break transient.

The reactor coolant system (RCS) peak pressure is within 110% of RCS design pressure, and meets the acceptance criteria.

K. Reactor coolant pump shaft seizure (locked rotor) (UFSAR Section 15.3.3)

This event was analyzed to show that the peak primary system pressure does not exceed the applicable limit, and to determine the percentage of fuel rods that experience DNB. The results of the transient analysis are insensitive to the secondary system. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000 and DPC-NE-3002.

In addition, the radiological consequences were reanalyzed by the licensee due to the differences in the thermal-hydraulic parameters of the feedring steam generator. Specifically, since the feedring generator design has tubes that are significantly taller than those in the Model D generators, the potential exists for a longer period of tube bundle uncovery, which negatively impacts the offsite dose calculation. The offsite dose results at the Exclusion Area Boundary (EAB) are acceptable as it was shown that none of the calculated doses exceed a small fraction (10%) of the 10 CFR Part 100 limits.

L. Steam generator tube failure (UFSAR Section 15.6.3)

This event is analyzed to show that (a) DNB does not occur, (b) the calculated offsite doses do not exceed the acceptance criterion, and (c) steam generator overfill is avoided. When the ruptured area of the tube is no longer covered with liquid, a significant reduction in the iodine partition factor occurs; therefore, tube bundle uncovery is an important phenomenon in the offsite analysis. Since the feedring steam generator design has tubes that are significantly taller than those in the Model D generators, the potential exists for a longer period of tube bundle uncovery. Other factors associated with the feedring steam generator which potentially impact the transient results are the reduced tube diameter and the revised SG level setpoints. The analysis was performed in accordance with the analytical model and methodology described in topical reports DPC-NE-3000, DPC-NE-3002, and WCAP-10698-PA.

The minimum DNB ratio was calculated to be 1.93, which is well above the 1.55 design limit. The staff issued its original evaluation of offsite radiological consequences by letter, R. Martin to M. Tuckman, dated May 14, 1991. The offsite doses recalculated by the licensee (August 27, 1996 letter) for the new steam generators are within applicable guideline values. The staff's 1991 calculation assumptions and results still bound the licensee's new assumptions and results. Also the time to overfill for the replacement generators was determined to be bounded by that for the Model D steam generators, which has been previously found acceptable.

M. Loss of coolant accidents (UFSAR Section 15.6.5)

DPC stated that a LOCA analysis, applicable to Catawba Unit 1, was performed by B&W Nuclear Technologies (BWNT). The analysis supports operation of the Duke units with the feedring steam generators. The methodology employed in the analysis is in accordance with 10 CFR 50.46 and 10 CFR Part 50, Appendix K and is documented in topical reports BAW-10174, Revision 1 (erroneously stated as Revision 2 in the September 30, 1994, submittal but corrected in the March 15, 1996, submittal), and BAW-10168P, Revision 3. The LOCA evaluation considered both large and small breaks.

The maximum cladding temperature calculated for a large break is 2,075 °F, which is less than the acceptance criteria limit of 2,200 °F specified by 10 CFR 50.46. The maximum local metal water reaction is 5.9%, which is well below the embrittlement limit of 17% as specified by 10 CFR 50.46. The total core metal water reaction is calculated to be 0.61% as compared with the 1% criterion of 10 CFR 50.46, and the cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. As a result, the core temperature will continue to drop and the ability to remove decay heat generated in the fuel for an extended period of time will be sustained. These results were found to be acceptable.

The maximum calculated peak cladding temperature for the small breaks analyzed was 1,200 °F. The licensee uses the methodology delineated in the topical report BAW-10168, Revision 2, "BWNT Loss-of-Coolant Accident Evaluation Model for Recirculating Steam Generator Plants," (approved by letter, R. Jones to J. H. Taylor, August 22, 1996) relating to the small-break LOCA. The licensee's result is acceptable as it is well below the acceptance limits of 10 CFR 50.46, and no case is limiting when compared to the results presented for the large breaks.

N. Effects on the "doghouse" from a postulated secondary system pipe rupture outside containment

This event is analyzed to ensure that the "doghouse" (a structure that contains the safety valves for the main steam and main feedwater lines) equipment qualification temperature limit is not exceeded. A key phenomenon in this analysis is tube bundle uncovery, since this initiates the release of superheated steam. Since the feedring steam generator design has tubes that are significantly taller than those of the Model D generators, the potential exists for earlier bundle uncovery. The analysis was performed in accordance with the analytical model and methodology described in topical report DPC-NE-3004. A comparison of the mass and energy release rates showed that the reanalyzed transient results were bounded by the existing vendor-supplied analysis. Therefore, an explicit "doghouse" temperature response calculation was not performed by the licensee.

2.2 Transients Reanalyzed For Offsite Dose Only

The radiological consequences were reanalyzed by the licensee for the following events due to the differences in the thermal-hydraulic parameters of the feedring steam generator. Specifically, since the feedring generator design has tubes that are significantly taller than those in the Model D generators, the potential exists for a longer period of tube bundle uncovery, which negatively affects offsite dose calculations. The two events listed are UFSAR Chapter 15 transients for which fuel failure is postulated to occur.

A. Single rod cluster control assembly (RCCA) withdrawal (UFSAR Section 15.4.3.4)

The offsite dose results at the Exclusion Area Boundary (EAB) were found not to exceed a small fraction (10%) of the 10 CFR Part 100 limits and are therefore acceptable.

B. Spectrum of RCCA ejection accidents (UFSAR Section 15.4.8)

The offsite dose results at EAB were found not to exceed 25% of the 10 CFR Part 100 limits and are therefore acceptable.

2.3 Transients Not Reanalyzed

For the following transients, the licensee indicated that reanalysis was not required, since either (a) the analysis is unaffected by the steam generator replacement, (b) any changes will not adversely impact the analysis result, or (c) the transient is bounded by a more limiting transient which is being reanalyzed.

A. Peak containment reverse differential pressure, containment subcompartment and minimum containment pressure analyses (UFSAR Sections 6.2.1.1, 6.2.1.2, and 6.2.1.5)

B. Feedwater system malfunction causing a reduction in feedwater temperature (UFSAR Section 15.1.1)

C. Loss of external load (UFSAR Section 15.2.2)

D. Inadvertent closure of main steam isolation valves (UFSAR Section 15.2.4)

E. Partial loss of forced reactor coolant flow (UFSAR Section 15.3.1)

F. Complete loss of forced reactor coolant flow (UFSAR Section 15.3.2)

G. Reactor coolant pump shaft break (UFSAR Section 15.3.4)

H. Uncontrolled rod cluster control assembly (RCCA) bank withdrawal from a subcritical or low power startup condition (UFSAR Section 15.4.1)

I. Uncontrolled RCCA bank withdrawal at power (UFSAR Section 15.4.2)

J. RCCA misoperation (UFSAR Section 15.4.3)

K. Startup of an inactive reactor coolant pump at an incorrect temperature (UFSAR Section 15.4.4)

L. Chemical and volume control system (CVCS) malfunction that results in a decrease in boron concentration in the reactor coolant (UFSAR Section 15.4.6)

M. Spectrum of RCCA ejection accidents (UFSAR Section 15.4.8)

N. Inadvertent operation of emergency core cooling system (ECCS) during power operation (UFSAR Section 15.5.1)

O. Inadvertent opening of a pressurizer safety or relief valve (UFSAR Section 15.6.1)

2.4 Technical Specification Changes

The major Technical Specifications changes proposed by the licensee, and the staff's evaluation of the changes, are delineated below. All the changes are found by the staff to be consistent with all the reanalyzed licensing basis safety analyses (above), and are therefore acceptable. Other changes pertain to requirements that are no longer applicable after the replacement of the steam generators, or are administrative in nature, reflecting the use of the most current revision of the topical reports.

o *Proposed Revision to Section 3/4.4.4*

The licensee proposed to change the surveillance requirements to delete repair methods that are no longer applicable after the replacement of the SGs. References to F*, sleeving, interim plugging criteria, or alternate

plugging criteria are deleted. The F* criterion relates to the determination of the minimum acceptable length of defect-free SG tubes within the tube-sheet to establish structural integrity.

This proposed change to the Technical Specifications deletes repair criteria that will no longer be applicable after the replacement of the SGs. References to F* criteria, sleeving, and interim plugging criteria are removed because these methods of repair were approved specifically for use on the original SGs. These changes will not alter the way surveillances are performed, and continue to meet the current intent of the requirements.

o *Proposed Revision to Tables 2.2-1 And 3.3-4*

The licensee proposed to change the low-low SG water level reactor trip setpoint from a variable setpoint that is proportional to nuclear power to a constant level setpoint of 10.7% of narrow range span.

These setpoints were chosen to maximize the plant operating region while still ensuring that reactor trip on low-low level would occur following a feedline break inside containment. The new low-low level setpoints are consistent with all reanalyzed licensing basis safety analyses. All of the reanalyzed transients that take credit for this trip function meet the applicable acceptance criteria, as stated above.

The feedwater system pipe break (also see Section 2.1.J above) was analyzed to demonstrate the capability of the degraded secondary system to effectively cool the core. The analysis was performed in accordance with NRC-approved methodology as described in topical reports DPC-NE-3000 and DPC-NE-3002. The staff has reviewed the impact of the design differences between the original preheat SGs and the replacement feedring SGs on structural modeling and analysis results. The feedwater system pipe break transient is significantly impacted by implementation of the feedring SGs, and requires several major assumption changes as a direct result of the design and location of the main feedwater nozzles. The licensee's discussion of assumption changes and the impact of changes in transient results was reviewed and found to be reasonable and acceptable.

For this accident, the loss of offsite power coincident with reactor trip is assumed, resulting in reactor coolant pump trip and delay in the startup of the diesel generators for safety injection. Early main steam isolation valve (MSIV) closure was determined to be conservative in terms of earlier faulted SG dryout. Thus, in the revised assumptions, MSIV closure occurs coincident with turbine trip, which occurs on loss of offsite power. The licensee's approach to the analysis of this event is acceptable.

The licensee also proposed to change T_{avg} value from 590.8 °F to 585.1 °F. In its September 18, 1995 submittal, the licensee stated that this new T_{avg} was chosen based on returning the secondary side steam pressure to the original value after replacement of the steam generators, and that the new T_{avg} was the assumed value for nominal full power in all

applicable safety analyses. These analyses were evaluated above in Section 2.1. Therefore, the staff finds the change acceptable.

o *Proposed Revision to Table 3.3-4*

The licensee proposed to change the high-high SG water level setpoint from a variable setpoint that is proportional to nuclear power to 83.9% of narrow-range span.

The low-low SG water level auxiliary feedwater actuation setpoint will be modified from a variable setpoint that is proportional to nuclear power to a constant level setpoint of 10.7% of narrow-range span.

The high-high setpoint was chosen to maximize the plant operating region while still ensuring that feedwater isolation on high-high level would occur before the actual water level in the SG reaching the flood point. The new high-high level setpoint is consistent with all reanalyzed licensing basis safety analyses. The results of the increase in feedwater flow analysis, which is the only UFSAR Chapter 15 transient that relies on this trip function, show that all applicable acceptance criteria are met. DPC Topical Report DPC-NE-3002, Revision 1, describes the DPC transient analysis methodology. The impact of the design differences between the feedring type replacement SGs and the original preheat SG on the feedwater flow analyses has been reviewed and approved by the staff as discussed earlier.

The rationale for the acceptance of the low-low SG water level auxiliary feedwater actuation setpoint is similar to that discussed above for Table 2.2-1.

o *Proposed Revision to Section 5.4.2*

The volume of the reactor coolant system (RCS) changes from 12,040 ± 100 cubic feet to 13,050 ± 100 cubic feet.

The mass and energy release for postulated loss-of-coolant accidents inside containment is analyzed to ensure that the peak containment pressure limit is not exceeded. Since the RCS volume is greater, the total mass released into containment will be greater. In addition, during the depressurization of the RCS, the SGs actually function as heat sources. Since the feedring SG full power liquid mass is greater than that of the Model D preheat SGs, the total energy available for removal by the RCS is increased. Both of these effects have the potential to yield more severe mass and energy release results. This event has been reanalyzed by the licensee, and shown to meet current acceptable limits relative to pressure, temperature, and stress allowables for the affected components (see also Section 2.1.A above).

Topical Report DPC-NE-3004-P describes DPC's methodology for simulating the mass and energy release and containment response to LOCAs and main steamline break accidents for the Catawba facility. The staff has previously reviewed and approved the analytical methodology including the

thermal-hydraulic computer codes for predicting Catawba containment pressure and temperature responses to design-basis accidents. The staff also reviewed the impact of the design differences between the existing preheat SGs and the replacement feedring SGs on the analysis results. The peak lower containment pressure was calculated to be 11.77 psi for Catawba Unit 1 which meets the acceptance criteria of 15 psig. Various break locations were analyzed and it was determined that the cold leg RCP discharge leg break case generates the highest energy release and the limiting large-break LOCA peak pressure. With feedwater flow and unaffected SGs promptly isolated, steam line break mass and energy releases are considerably less than that of the limiting LOCA. However, since the blowdown fluid is superheated, the licensee has examined the lower containment temperature response to ensure that environmental qualification limits for safety-related equipment are not exceeded.

The steam line break inside containment is limiting from considerations of environmental qualification of equipment structures and components in the lower containment. The peak temperature in the break compartment is calculated to be 313°F with the original SGs. This is considered to be the bounding temperature and encompasses the design changes in the replacement feedring SGs. This calculated value is well below the environmental qualification (EQ) limit of 340°F and therefore acceptable (see also Section 2.1.B above).

o *Proposed Revision to Section 6.9.1.9*

The licensee proposed to change the references to topical reports DPC-NE-3000 and DPC-NE-3002 to reflect the use of the most current approved revisions. As stated in Section 2.0 above, these revisions have been approved by the staff. The proposed changes are thus acceptable.

o *Sections 3/4.4.5 and Associated Bases, Table 4.4-1, Table 4.4-2*

The licensee proposed to delete the alternate tube repair criteria from the existing steam generators TS. With the replacement steam generators, the alternate repair criteria are no longer necessary; the staff finds the deletion of these acceptable.

Based on its review, the staff concludes that the proposed changes related to the Catawba Unit 1 SG replacement are acceptable.

3.0 STATE CONSULTATION

In accordance with the Commission's regulations, the South Carolina State official was notified of the proposed issuance of the amendments. The State official had no comments.

4.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (April 10, 1996, 61 FR 15986). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

5.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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