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

DEC 2 0 1988

MEMORANDUM FOR: George W. Knighton, Director
Project Directorate V
Division of Reactor Projects - III/IV/V
and Special Projects

FROM: C. Y. Cheng, Chief
Materials Engineering Branch
Division of Engineering and Systems Technology

SUBJECT: EVALUATION OF JUSTIFICATION FOR CONTINUED OPERATION OF DIABLO CANYON UNIT 1 (TAC NO. 69826)

The enclosed evaluation was prepared by the Materials Engineering Branch (EMTB) to provide the results of the staff's review of the Justification for Continued Operation (JCO) dated October 19, 1988, and revised JCO dated October 20, 1988, submitted by Pacific Gas and Electric (PGME), the licensee for Diablo Canyon Power Plant (DCPP), Unit 1. The JCO was necessary, because during a surveillance activity associated with the current DCPP Unit 2 refueling outage, the licensee found broken studs in Anchor/Darling, Model S350W check valve No. RHR-2-8740A. The hanger bracket studs were of type 410 stainless steel material and the cause of failure was determined to be stress corrosion. When the condition of valve RHR-2-8740A was found, an Event Response Plan was initiated and actions were begun immediately by the licensee. Also the licensee performed an 10 CFR 50.59 evaluation as part of the JCO and the staff has summarized it in the enclosed EMTB evaluation.

The licensee's effort showed that the valve population of concern was ten Anchor/Darling check valves in each of the two DCPP Units. The remainder of the ten identified DCPP Unit 2 Anchor/Darling check valves were inspected by the licensee and no cracks were found. In addition the licensee replaced all studs in the ten DCPP Unit 2 Anchor/Darling check valves. Thus, the licensee proposes operation of DCPP Unit 1 until the next refueling outage currently scheduled for October 1989, at which time the licensee will inspect and replace all the studs in the ten identified Anchor/Darling check valves. In addition, if an unscheduled outage occurs for DCPP Unit 1, before the October 1989 refueling outage, the licensee has committed to inspect and replace the studs for valves RHR-1-8740A & B. If time permits the licensee has stated it will inspect valves the SI-1-8956A, B, C, & D valves. The staff believes that every effort should be made by the licensee to complete this work if a forced outage occurs.

The staff has already issued Information Notice 88-85 on this subject. A Bulletin is currently being prepared by the NRC staff and any actions so specified in the Bulletin would supersede those proposed by the licensee in the JCO.

Robert A [signature]
for C. Y. Cheng, Chief
Materials Engineering Branch
Division of Engineering and Systems Technology

CONTACT: C.D. Sellers
X20930

8812270132-XA

Enclosure: as stated

cc: L. Shao
G. Holahan
J. Richardson
R. Herman
H. Rood
T. Miller
T. McLellan
C. Sellers

PACIFIC GAS AND ELECTRIC

DIABLO CANYON UNIT 1

EVALUATION OF LICENSEE'S PROPOSED JUSTIFICATION FOR CONTINUED OPERATION OF UNIT 1

I. LICENSEE BASIS FOR CONTINUED OPERATION

Letters proposing Justification for Continued Operation (JCO) dated October 19, 1988 and a revised JCO dated October 20, 1988 were submitted by Pacific Gas and Electric (PG&E), the licensee for Diablo Canyon Power Plant (DCPP), Unit 1. The JCO was proposed because during a surveillance activity associated with the current DCPP, Unit 2 refueling outage, the licensee had found broken hanger bracket studs in an Anchor/Darling, model S350W check valve RHR-2-8740A. The hanger bracket studs were of ASTM A193 B6 (AISI Type 410 stainless steel) and the cause of the failure was determined to be stress corrosion. When the condition of valve RHR-2-8740A was found, Event Response Plan 88-008 was initiated and actions were begun immediately by the licensee. These actions encompassed a full area of investigation to determine the potential extent of the noted condition and to assess the impact of such stud failures on DCPP Unit 1 and 2 plant safety and operation. Key activities included: record review to establish the population of potentially affected valves and their history; possible impact on valve performance; review of the impact on valve operation and on required safety function; valve internals physical geometry studies using CAD (computer assisted drafting) techniques; and a program to develop a method of radiographic non-destructive examination.

II LICENSEE ANALYSIS

The licensee's results from these efforts showed that the valve population of concern was ten Anchor/Darling check valves in each Unit. There were two eight inch valves 8740A and B in the RHR line to hot leg recirculation and eight ten inch valves (8748A-D) in the cold leg injection lines from the accumulators. All valves were within the containment building. These valves had complete material records and test/maintenance records which showed consistent reliable performance including valve RHR-2-8740A.

*The failure mechanism appeared to have occurred early in plant life because valve SI-2-8948B was found to have had a cracked stud in 1984 prior to plant operation. The crack surface had corrosion product buildup. So it was concluded the failure occurred during earlier layup periods.

*Valve RHR-2-8740A had corrosion products on the fracture surfaces of the failed studs and evidence of side root cracking from the fracture surface into the stud body.

*A red contaminant (most likely rust) was found deposited in RHR-2-8740A. This would have come from poor layup conditions not operational chemistry.

*No failed studs were found in SI-2-8956A-D. These valves have seen over three years of borated water service.

The licensee also indicated that any failed studs on Unit 1 most likely failed early on in startup flushing, testing, and layup periods, their surveillance test program has challenged these failed studs multiple times with no double stud failures detected. Also, if a contaminant is the cause, they do not expect operational water chemistry to accelerate SCC.

However, a computer enhanced radiographic analysis of two valves in what was considered to be the worst environment of the 10 valves, RHR-1-8740A&B, showed a possible indication of a crack in one of the studs.

The licensee proposed the JCO until the next refueling outage, scheduled for October 1989, and has proposed to inspect and replace all the studs in the ten DCPP, Unit 1 Anchor/Darling Valves. In addition if an unscheduled outage for DCPP, Unit 1 occurs before the October 1989 refueling outage; the licensee will inspect and replace the studs for valves RHR-1-8740A & B, and if time permits the licensee will do the same for the SI-1-8956A, B, C & D valves. A bulletin is currently being prepared to provide a solution to the problem and will supersede the JCO.

The licensee has performed a 10 CFR 50.59 evaluation as part of the submitted JCO which is summarized below:

1. The licensee claims that the potential effects of degraded valve disc retaining block studs have been evaluated under an Event Response Plan. The capability of the valves were evaluated for normal plant operation and for required function in an accident mode. The valves are passive components and the condition of the retaining block studs has no impact on their ability to remain seated and retain pressure as designed for normal plant operation, as evidenced by surveillance test program results. Also the condition of the retaining block studs does not affect the pressure boundary or the ability of the valves to open when required in response to an accident. CAD studies have shown that there will be no loose parts outside of the valve casing to affect other equipments. The valves therefore will not increase the probability of occurrence or the consequence of an accident or malfunction of equipment important to safety previously analyzed in the safety analysis report.

2. The licensee further claims that the valves are in the closed position during normal plant power operation (Modes 1, 2 and 3). The valves will provide proper function in the closed mode as documented through test. This function of providing inter-system pressure protection and inter-system LOCA protection is not impacted as the condition of the studs was shown to have no bearing on the closed function of the valve. There are no other functions of the valves associated with normal plant at power operation, consequently the studs do not have an effect on continued normal safe operation of the plant. Likewise continued plant operation with the valves providing their normally closed function does not increase the possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report.

3. The licensee also stated that the valves are expected to open when required to fulfill their initial safeguards function, as demonstrated by periodic testing. The licensee admits to the possible failure to reseat

after initial opening. Analysis shows that reseating is the most likely result, which is supported by the test records. However the potential consequences of failure to reseat have been evaluated and found to be acceptable. A situation could be postulated where the valve disc/seat orientation is lost. In the worst case, a complete orientation loss leading to a loose valve disc was postulated and evaluated. The evaluation addresses the anticipated effects on the performance of the ECCS and the impact on the margin of safety. In addition, the Probabilistic Risk Assessment (PRA) calculates a negligible change (using quite conservative assumptions) in risk factor by allowing continued operation of DCPP Unit 1. The results of the analysis, records evaluation, inspections of Unit 2 valves, and Unit 1 radiographs provide confidence of the operability of the Unit 1 valves. The continued operation of the plant does not reduce the margin of safety as defined in the basis for any Technical Specification.

III STAFF REVIEW

Based on the following factors:

1) The licensee's evaluation;

2) The absence of any evidence of check valve malfunction with failure of the hanger bracket studs

3) The probability of similarity of conditions of other plants for which there is currently no requirement for action relative to similar valves.

The staff concurs with the licensee's conclusion that DCPP Unit 1 can operate safely and not create an unreviewed safety question without inspecting valves RHR-1-8740A&B, SI-1-8940A, B, C, & D, and SI-1-8956A, B, C, & D until the next refueling outage scheduled for October 1989. In addition, continued operation will not adversely affect the health and safety of the public.

LICENSEE EVENT REPORT (LER) 122334

Facility Name: DIABLO CANYON UNIT 2

Docket Number: 0 5 0 0 0 3 2 3 | Page 1 of 1

Title: ANCHOR DARLING CHECK VALVE RETAINING BLOCK STUD BREAKAGE DUE TO INTERGRANULAR STRESS CORROSION CRACKING

Event Date (Month/Day/Year)	LER Number (Year/Sequential/Revision)	Report Date (Month/Day/Year)	Other Facilities Involved	Docket Number
1 0 0 9 8 8	8 8 — 0 1 4 — 0 0	1 1 1 8 8 8	DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5
				0 5 0 0 0

Operating Mode: N

Power Level: 0 0 0

VOLUNTARY REPORT

Licensee Contact for this LER: JAMES C. NOLAN, REGULATORY COMPLIANCE ENGINEER

Telephone Number: 8 0 5 5 9 5 - 7 3 5 1

Complete One Line for Each Component Failure Described in this Report

Cause	System	Component	Manufacturer	Reportable to NPRDS	Cause	System	Component	Manufacturer	Reportable to NPRDS
B	1 0 8	7 4 0 A A	3 9 5	YES					

Supplemental Report Expected: NO

Abstract:

This report is being voluntarily submitted for information purposes only as described in item 19 of Supplement Number 1 to NUREG 1022.

On October 9, 1988, at 0430 PDT during a preventative maintenance (PM) inspection, both retaining block studs for check valve RHR-2-8740A were observed to be broken. The four disc arm alignment guide pins were intact. Manual valve cycling during PM showed no significant misalignment or disc-to-body contact. This valve had passed previous surveillance testing and was considered operable prior to disassembly.

The failed studs are made of ASTM A193 B6 Type 410 SS. Examination of the studs showed intergranular stress corrosion cracking as the failure mechanism. Similar valves in Unit 2 were disassembled and the studs were removed for inspection. Nondestructive examination of the studs from the other nine Unit 2 valves showed no abnormalities. Studs in all similar Unit 2 valves were replaced with vendor recommended ASTM A564 type 630-1100 material.

Radiographic testing of the two accessible Unit 1 RHR check valves confirmed there were no broken retaining block studs. However, computer-enhanced radiography showed a possible crack in one of the studs. The studs in similar Unit 1 valves will be replaced by the end of the next Unit 1 refueling outage.

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I. Initial Conditions

Unit 1 was in Mode 1 (Power Operation) and Unit 2 was in a refueling outage with all fuel removed from the reactor vessel when the event occurred. Both Units have been operating at various modes and power levels with these broken check valve retaining block studs.

II. Description of Event

A. Event:

Valve RHR-2-8740A (BP) (V) was chosen for internal inspection in accordance with the preventative maintenance program administered by Maintenance Procedure (MP) M-51.14, "Check Valve Maintenance Program." This valve is located in the Residual Heat Removal (RHR) hot leg injection line immediately adjacent to a piping elbow. This valve is an Anchor Darling model S350W 8-inch swing check valve.

On October 9, 1988, during a Unit 2 refueling outage valve inspection, two broken retaining block studs were found in check valve RHR-2-8740A. The broken studs were found after the valve had been manually cycled through its travel arc twice with no apparent problems. One stud was severed flush with the valve body while the other stud had a stub extending about 1-9/16 inches into the retaining block. Four alignment guide pins were observed to be in place and intact in the retaining block to valve body mating surface. The studs were made of ASTM A193 B6 type 410 stainless steel (SS).

Each Unit has a total of 10 valves of this design installed. All of the Unit 2 valves were disassembled and those Unit 1 valves that are accessible were examined by radiography (RT).

On October 10, 1988, ultrasonic testing (UT) of the check valve studs from valve RHR-2-8740B (BP) (V) showed no discontinuities. Disassembly of the remaining Unit 2 suspect check valves was initiated. During document review, a previous occurrence of a failed retaining block stud in a check valve of this design due to intergranular stress corrosion cracking (IGSCC) was identified in 1984 during Unit 2 startup testing.

On October 13, 1988, RT of Unit 1 valves RHR-1-8740A & B commenced utilizing a Cobalt 60 source. The studs from the other nine Unit 2 check valves were magnetic particle fluorescent dye tested (MT) and showed no cracking. Reassembly of the Unit 2 check valves was completed with a vendor-approved alternate material for the studs.

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On October 15, 1988, RT of an assembled check valve with a flawed stud (installed for test purposes) demonstrated that a cracked stud can be seen using a miniature linear accelerator as an RT source.

On October 17, 1988, the failure mechanism for the studs in valve RHR-2-8740A was confirmed by a materials testing laboratory to be IGSCC.

On October 19, 1988, RT of Unit 1 valves RHR-1-8740A & B utilizing the miniature linear accelerator was completed. A computer-enhanced radiograph of valve RHR-1-8740B showed a possible crack in one stud close to the retaining block to valve body mating surface.

B. Inoperable structures, components or systems that contributed to the event:

None.

C. Dates and approximate times for major occurrences:

October 9, 1988 at 0430 PDT:	Broken studs were found in RHR-2-8740A.
October 10, 1988 at 0200 PDT:	UT of RHR-2-8740B showed no discontinuities.
October 10, 1988 at 0900 PDT:	Other similar Unit 2 valves opened for inspection.
October 13, 1988 at 0300 PDT:	RT of RHR-1-8740A & B commences. MT of Unit 2 studs showed no cracking.
October 15, 1988 at 1800 PDT:	Mockup testing showed RT with a linear accelerator can detect a broken stud.
October 17, 1988 at 1600 PDT:	Failure mechanism confirmed to be IGSCC.
October 19, 1988 at 1400 PDT:	A possible crack was identified in RHR-1-8740B retaining block stud.

D. Other systems or secondary functions affected:

None.

E. Method of discovery:

During a routine outage inspection, the maintenance crew observed unusual motion in the retaining block of check valve RHR-2-8740A after a few manual valve cycles.

INPO SOER 86-03 identified and listed various past failures in check valves in many operating nuclear plants. As a result of the concerns identified in SOER 86-03, EPRI undertook various studies and experiments which resulted in an EPRI application guideline for various check valve designs. Among the reasons for failure identified in the EPRI guideline were location in the piping system and the operating conditions to which they are subjected.

On the basis of this guideline, PG&E Nuclear Engineering and Construction Services (NECS) reviewed all 3-inch and larger safety-related check valves plus certain Main Steam and Feedwater check valves in Unit 2 and issued a report to Plant Maintenance requesting an inspection of 26 check valves in Unit 2 in accordance with MP M-51.14. Valve RHR-2-8740A was selected as part of this inspection sample. The scope of the inspection was to open the selected valves and visually inspect for any broken items, excessive wear, proper alignment, and security of retaining devices.

Check valve RHR-2-8740A is in the RHR recirculation line to the RCS hot leg. In accordance with the inspection program, the cover of this valve was removed and a visual inspection was made of the internal configuration.

During the initial inspection of the valve internals, no abnormalities were noted. The disc was rotated to check if it was free and nothing unusual was noted at that time. As the inspection progressed the disc arm was manually operated by swinging it to observe if any binding existed. During this phase of the inspection the mechanic noted unusual play in the retaining block studs and the retaining block. At this point a closer inspection of the retaining block and studs was performed.

The valve internals were again cycled by hand with emphasis placed on inspection of the retaining block and block studs reaction to valve manipulation. The block was loose and the studs showed signs of movement. Upon examination, the studs were found to be broken; the left stud was sheared in the location of the block to valve body connection, and the right stud was broken off inside the retaining block assembly with approximately 1-9/16 inches protruding from the valve body.

The only abnormalities noted were in the 10 to 12 o'clock position (facing the valve seat from downstream) outside the in-body seat area, and consisted of wear marks 3/8 inches wide and estimated to be 1/32 to 1/16 of an inch deep (see drawing: Attachment 1). Precise measurements were not possible due to radiological clothing interference and difficult accessibility. The wear marks could have been caused by disc-to-body contact. The mechanic noted that the retaining block studs had significant corrosion product buildup.

F. Operator actions:

None.

G. Safety system responses:

None.

III. <u>Cause of Event</u>

A. Immediate cause:

IGSCC caused retaining block studs to fail in service.

B. Root cause:

The manufacturer's incorrect heat treatment of the check valve retaining block studs caused susceptibility to IGSCC. This was determined by material analysis, hardness testing, and microscopic section examination of the studs in a materials laboratory.

IV. Analysis of Event

A. Computer Assisted Drafting Valve Geometry Analysis:

The Anchor Darling swing check valves involved in this evaluation are designed with very close tolerances. This design provides a valve which is hydraulically similar to a straight piece of pipe. A large diameter bonnet is placed over the body to house the disc when it is lifted by the flow. The disc diameter is the same as the pipe OD, while the seat ID is equal to the pipe ID. The valve body is enlarged only enough to allow the disc to swing down into the flow and cover the seat.

The effects of degraded hardware were evaluated by use of a computer assisted drafting (CAD) model developed from the manufacturer's original shop fabrication drawings. The resulting model shows that since the stud nuts are tack welded to the retaining block, there is a low probability that loose parts could exist in the valve body which could potentially affect other system components. Study of this model showed that should only one stud fail, the operation of the valve will be unaffected since the two guide pins in each retaining block will prevent any movement or misalignment.

The CAD model was developed to evaluate the consequence of the worst case failure of both studs holding the retaining blocks in place. The results show that the most likely effect would be no detectable change in the performance of the valve. This results from the close fabrication tolerances which create a guide to direct the disc to travel in its normal design path. The four guide pins prevent lateral movement. The disc swing arm geometry provides for little uplift force until the disk is well up out of the flow path. The guide design combined with the weight of the disc is sufficient to maintain the location of the assembly. The physical evidence confirms this evaluation since the disc assembly in RHR-2-8740A remained in its design location and apparently functioned properly even though both retaining block studs failed.

The worst case failure of the valve would be the disc rotating normally from the bottom out of the flow stream. Detachment, if postulated, would probably occur at two-thirds of full disk rotation up out of the flow stream. The model shows that the swing arm would prevent the top of the disc from rotating back into the flow and the bottom could not move downstream without becoming wedged in the valve body up out of the flow stream. No significant flow restriction would result, although the valve may not reseat.

An evaluation of the flow effects was performed on the RHR Hot Leg Recirculation line. With one of the RHR check valves postulated to be blocked and the other valve with only a 20% free flow area, the flow reduction is only 10 to 15% of normal flow. The RHR flow rate is adjusted through the Flow Control Valves (FCV). With increased friction, due to valve blockage in the system, the FCV's would open wider to allow more flow to compensate for the friction increase. The actual flow reduction would be insignificant. This shows that the reduced transient condition and the full flow test conditions are comparable, and that the full flow tests are indicative of valve functionality for the reduced transient.

B. Hydraulic Analysis

Even though it has been demonstrated that the valves remain operable with broken studs, it is worth noting that the LOCA analysis is suitably conservative to accommodate some degree of flow blockage (although that is not postulated in this case).

Based on the existing margins to the peak clad temperature limit of 10 CFR 50.46 that exist in the FSAR Update, Westinghouse judges that if a small break LOCA analyses were performed using the best estimate technique, for lines six inches in diameter and smaller, with the assumption of a failure of one accumulator to discharge, the resulting peak clad temperatures would not exceed the limit. The assumption of no discharge from one accumulator is conservative as this results in discharge of only two accumulators into the RCS, since one accumulator is already assumed to be lost due to the initiating pipe break event.

Based on analysis performed for many plants and accepted by the NRC, leak-before-break (LBB) has been demonstrated for the reactor coolant loop piping and large branch lines attached to the loop (down to and including 8-inch lines). Therefore, the LOCA assumed for this evaluation is the rupture of a line six inches or smaller attached to the loop, although evaluations show that even for smaller lines, the mode of failure would still be LLB. For this case, the accumulators would still be required to operate, but at a reduced flow, and with lower loads on the check valves in the discharge line.

The flow conditions which check valves 8948A-D and 8956A-D would experience during the above assumed best estimated LOCA case has been calculated by Westinghouse to be a peak flow of approximately 7,300 gpm. The analysis of the hydraulic forces acting on the valve internals shows that the disc will lift to its full flow position with the flow used in the flow test (2000 gpm through 8948) and that additional flow does not result in increased lifting of the valve disc. The disc floats above the flow. Consequently, the valve disc and arm force balance during flow testing and are representative of valve forces during the maximum expected LOCA flows.

Based on an evaluation by Westinghouse, it is believed that the guide pins are sufficient to assure proper operation of the valve disc. An analysis of the hydraulic forces acting on the valve internals confirms the capability of these pins (two per block, four per valve) to withstand the loads imposed during opening of the valve and during full flow operation. This demonstrates that the capability of the retaining block studs is not required to maintain the valve disc in the open position. The disc assembly is not expected to lift off of the guide pins and proper seat/disc orientation is maintained. The worst failed condition of the studs has been assumed in the analysis, i.e. both retaining block studs were assumed to be broken at the retaining block/valve body interface. Inspection data obtained to date indicate stud failure locations which vary from the block/body interface to points higher up inside the retaining block. A failure of the stud inside the retaining block leaves a stub portion of the stud which would assist in maintaining disc orientation and which could provide additional load carrying capacity.

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Based on the analysis of this event, operation of DCPP Units 1 and 2 did not and does not now create an unreviewed safety question and will not adversely affect the health and safety of the public.

V. Corrective Actions

A. Immediate Corrective Action:

A search was made to locate all valves having the potential for a similar stud failure. Ten Anchor Darling valves of this model were identified in each Unit: 8740A & B in the RHR hot leg injection, 8956A through D (BP) (V) for the accumulators, and 8948A through D (BP) (V) for the SI to the cold leg injection. In addition to the inspection performed on RHR-2-8740A, the other nine Unit 2 Anchor Darling check valves were also inspected. The studs of the other RHR valve 8740B, the 8948A through D, and the 8956A through D SI valve studs showed no cracking in MT inspection. No wear marks or disc binding were observed in these valves.

A review of maintenance records for Anchor Darling check valves showed that in November 1984 an inspection of valve SI-2-8948B following a failed leak check test revealed one of the two retaining block studs was broken. The cause of this failure was determined to be IGSCC.

Microscopic examination of a 410 SS stud from valve RHR-2-8740B, after sectioning and polishing, showed no cracking present. Hardness testing of this stud indicated it had correct heat treatment. The hardness of SI-2-8948A and SI-2-8956A studs indicated they were susceptible to IGSCC, but microscopic examination showed no cracking had occurred in three years of service in borated water.

B. Corrective Action to Prevent Recurrence:

All Unit 2 Anchor Darling check valve retaining block studs have been replaced with studs made of vendor recommended ASTM A564 type 630-1100 material.

All Unit 1 Anchor Darling check valve retaining block studs will be replaced with studs made of vendor recommended ASTM A564 type 630-1100 material before the end of the next refueling outage.

VI. Additional Information

A. Failed components:

Check valve RHR-2-8740A, an Anchor Darling S350W 8-inch swing check valve.

B. Previous LERs on similar events:

None.

C. Similar designs by other manufacturers:

Nineteen Velan check valves were identified (11 in Unit 1 and 8 in Unit 2) that use 410 SS material for the retaining block studs. These valves are in the Auxiliary Feedwater (AFW) System and Main Steam (MS) to the turbine driven AFW pump. Records show that nine of these valves have been inspected or replaced since 1985. The MS valves are full flow tested on a monthly basis and the valves in the AFW system are tested at each cold shutdown. Based on the testing results and on the difference in chemistry for these valve applications, these valves are not considered to have the same stress corrosion cracking failure mechanism potential as the ECCS check valves. There are no entries in NPRDS for retaining block stud breakage for Velan check valves and the manufacturer was unaware of any failures of this type.

D. Related documents:

SOER 86-3, issued by INPO on October 15, 1986, provides recommendations for a check valve preventative maintenance program which are being implemented in a change to MP M-51.14.

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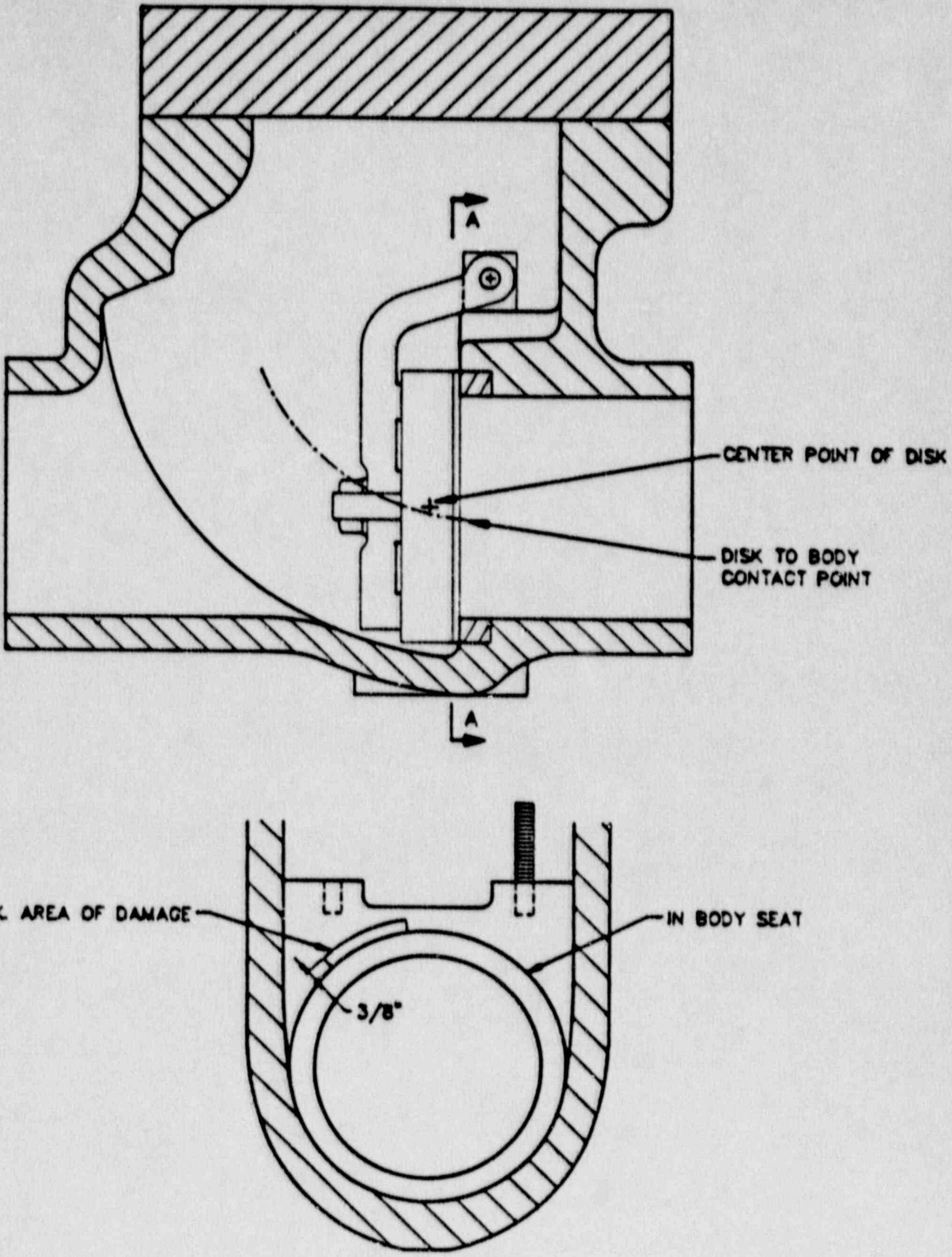

SECTION A-A

SCALE: 3/8" = 1"

ANCHOR DARLING CHECK VALVE

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/972-7000
TWX 910 372-6587

James D. Shiffer
Vice President
Nuclear Power Generation

November 18, 1988

PG&E Letter No. DCL-88-281

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

Re: Docket No. 50-323, OL-DPR-82 Docket No. 50-275, OL-DPR-80
Diablo Canyon Units 1 and 2
Licensee Event Report 2-88-014-00 - Voluntary
Anchor Darling Check Valve Retaining Block Stud Breakage Due To
Intergranular Stress Corrosion Cracking

Gentlemen:

PG&E is submitting the enclosed voluntary Licensee Event Report (LER) regarding Anchor Darling check valve retaining block stud breakage due to intergranular stress corrosion cracking. This report is being submitted for information purposes only, as described in item 19 of Supplement Number 1 to NUREG 1022.

This event has in no way affected the public's health and safety.

Kindly acknowledge receipt of this material on the enclosed copy of this letter and return it in the enclosed addressed envelope.

Sincerely,

J. D. Shiffer

cc: J. B. Martin
M. M. Mendonca
P. P. Narbut
B. Norton
H. Rood
B. H. Vogler
CPUC
Diablo Distribution
INPO

Enclosure

DC2-88-MM-N111

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Indiana Michigan
Power Company
P.O. Box 16631
Columbus, OH 43216

INDIANA
MICHIGAN
POWER

AEP:NRC:1054

Donald C. Cook Nuclear Plant Unit Nos. 1 and 2
Docket Nos. 50-315 and 50-316
License Nos. DPR-58 and DPR-74
VOLUNTARY REPORT: DEGRADATION OF RETAINING BLOCK
STUDS IN DARLING VALVE AND MANUFACTURING COMPANY
CLEAR WATERWAY CHECK VALVES

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

Attn: A. B. Davis

October 28, 1988

Dear Mr. Davis:

The purpose of this letter is to provide you with information concerning recently observed degradation of A-193 Grade B6 Type 410 stainless steel retaining block studs in Darling Valve and Manufacturing Company Clear Waterway check valves installed at the Cook Nuclear Plant. The observed condition did not result in any check valve failures, and we have determined that the condition was not reportable under Title 10 CFR or our technical specifications (T/Ss). However, because degradation of the type observed at the Cook Nuclear Plant has been of general industry interest in the past (e.g., INPO Significant Operating Experience Report [SOER] 86-03), we have elected to submit this voluntary report. A summary of the observed condition and actions we have taken is provided below.

Background

In conjunction with the performance of other maintenance on 8" Darling Clear Waterway swing check valve (2-SI-151W) installed in the low pressure emergency core cooling system (ECCS), an inspection of the valve internals was performed in accordance with the maintenance program that we established in response to INPO SOER 86-03. During this inspection, one of the two retaining block studs was found broken and the other cracked. A diagram of the valve type in question is provided in Figure 1. The retaining block studs (Part No. 11542-61-5) retain the blocks (Part Nos. 11542-60/60-1) that hold the valve disc assembly in place. As a result of this finding, the corresponding check valve (2-SI-151E) in the redundant low pressure ECCS train was

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8pp.

inspected. Again, one of the two retaining block studs was found broken and the other cracked. Discovery of this second instance prompted the expansion of the inspection to all Unit 2 Darling check valves of the same design as those in which the degraded studs were found. There are 12 valves of this design installed in the ECCS and RHR systems in each unit at Cook Nuclear Plant. All of these valves are classified as pressure isolation valves (PIVs) and leak tested in accordance with our IST valve program. They are:

- (4) 10" check valves at the accumulator outlet (SI-166L1, L2, L3, L4)
- (4) 10" check valves ECCS injection to cold legs (SI-170L1, L2, L3, L4)
- (2) 8" check valves low pressure ECCS (SI-151E & W)
- (2) 8" check valves normal RHR (RH-133, -134)

Figure 2 provides a simplified flow diagram which identifies the locations of these check valves in either unit at Cook Nuclear Plant.

Soon after the decision was made to initiate the inspection of Unit 2 check valves however, Unit 1 went from power operation to hot shutdown (Mode 4) due to an unrelated event. As a result, a decision was made to immediately inspect all Unit 1 check valves of this design accessible in Mode 4. In Unit 1, the only check valves accessible for inspection during the Mode 4 forced outage were 1-SI-151E, 1-SI-151W, 1-SI-166L1, and 1-SI-166L4. The Unit 1 inspections found one broken stud in each of the check valves installed in the low pressure ECCS (1-SI-151E & W) and stud material with an appearance not typical of Type 410 stainless steel in each of the two accessible accumulator outlet valves (1-SI-166L1, & L4).

The continuing Unit 2 inspections identified one additional check valve with one cracked stud (2-SI-166L4), and one valve (2-SI-166 L1) in which, although the studs were intact, the stud material did not have the appearance typical of Type 410 stainless steel, the material specified on the valve drawing for the retaining block studs. Both valves are located on the accumulator outlet. A summary of inspection results for the valves inspected in both Unit 1 and Unit 2 is provided in Table 1.

Actions Resulting from Check Valve Inspections

In each of the cases discussed above, the cracked or broken studs, or studs of a material having an appearance not typical of

Type 410 stainless steel were replaced with A-193 Grade B8 stud material. This new stud material is recommended by the valve manufacturer for this application. In addition, maintenance job orders were initiated to replace all A-193 Grade B6 Type 410 stainless steel studs with the new A-193 Grade B8 material regardless of whether any degradation is currently evident. This action is also in accordance with the valve manufacturer's recommendation. To date, retaining block studs in 10 of the 12 Unit 2 check valves and 4 of the 12 Unit 1 check valves have been replaced with the new A-193 Grade B8 stud material. The studs in the remaining Unit 2 check valves will be replaced during the current steam generator repair project outage. The studs in the remaining Unit 1 check valves are to be replaced during the next scheduled outage, with the possible exception of those installed in the low pressure injection lines to the cold legs (1-SI-170L1, L2, L3 and L4). Service conditions for these valves may not be conducive to the type of stud degradation observed in the other systems inspected. Westinghouse, who supplied the check valves under the original NSSS contract, and Darling, the valve manufacturer, were advised of the inspection findings discussed above. Westinghouse is conducting metallurgical evaluations to determine the root cause of the stud degradation.

Evaluation of Safety Significance

With regard to the evaluation of the safety significance of our valve inspection findings, the following key factors were considered:

1) The check valves in their as-found condition had not failed, nor was valve operability impaired.

2) Inadvertent pressurization of a low pressure ECCS system is precluded since in each case where a check valve with potentially degraded studs was found, at least two valves were available to prevent back leakage from the reactor coolant system.

3) The check valves would have performed their intended function (i.e., opened) in the event of a LOCA regardless of whether the retaining block studs had completely failed.

4) Of the 10 valves inspected on Unit 2, three showed degradation of the retaining block studs and one was found to have questionable stud material. The corresponding Unit 1 valves which see the same service conditions as Unit 2 were inspected and studs replaced with the new stud material. No anomalies were observed in the remaining Unit 2 check valves inspected.

5) The Unit 2 valves in the degraded condition had functioned successfully in passing the required flow during Mode 5 or 6 operation at the beginning of the steam generator repair outage. Successful operation of these valves during this evolution is equivalent to passing the full flow test normally performed to confirm valve operability.

Unit 1 was returned to service on September 15, 1988, and the actions discussed above to replace retaining block studs on both units have commenced.

This document has been prepared following Corporate procedures which incorporate a reasonable set of controls to ensure its accuracy and completeness prior to signature by the undersigned.

Sincerely,

M. P. Alexich
Vice President

ldp

cc: D. H. Williams, Jr.
W. G. Smith, Jr. - Bridgman
R. C. Callen
G. Charnoff
A. B. Davis
NRC Resident Inspector - Bridgman
G. Bruchmann

TABLE 1

SUMMARY OF ANCHOR/DARLING CHECK VALVE INSPECTIONS

	Valve	Size	Service Location	Retaining Block Stud Condition
Unit 1				
	1-SI-151E	8"	Safety Injection (SI) To Hot Legs	One Broken Stud[1]
	1-SI-151W	8"	SI To Hot Legs	One Broken Stud
	1-SI-166L1	10"	Accumulator Outlet	Questionable Stud Material[2]
	1-SI-166L4	10"	Accumulator Outlet	Questionable Stud Material
Unit 2				
	2-RH-133	8"	Residual Heat Removal (RHR) To Cold Leg	OK
	2-RH-134	8"	RHR To Cold Leg	OK
	2-SI-151E	8"	SI To Hot Legs	One Broken Stud One Cracked Stud[3]
	2-SI-151W	8"	SI To Hot Legs	One Broken Stud One Cracked Stud
	2-SI-166L1	10"	Accumulator Outlet	Questionable Stud Material
	2-SI-166L2	10"	Accumulator Outlet	OK
	2-SI-166L3	10"	Accumulator Outlet	OK
	2-SI-166L4	10"	Accumulator Outlet	One Cracked Stud
	2-SI-170L1	10"	Low Pressure Injection To Cold Leg	OK
	2-SI-170L4	10"	Low Pressure Injection To Cold Leg	OK

Table 1 Notes:

1) A broken stud is a stud that has completely sheared into two parts. In each case where a broken stud is reported, the break occurred at or near the plane of the interface between the valve body and the retaining block.

2) Questionable stud material refers to studs that looked shiny instead of having the black appearance typical of Type 410 stainless steel, the material listed on the valve drawings for the retaining block studs. It appears that the "as-found" material is either Type 304 or 316 stainless steel.

3) A cracked stud is a stud that has partially sheared but has not parted into two pieces.

FIGURE 1: DARLING CLEAR WATERWAY CHECK VALVE

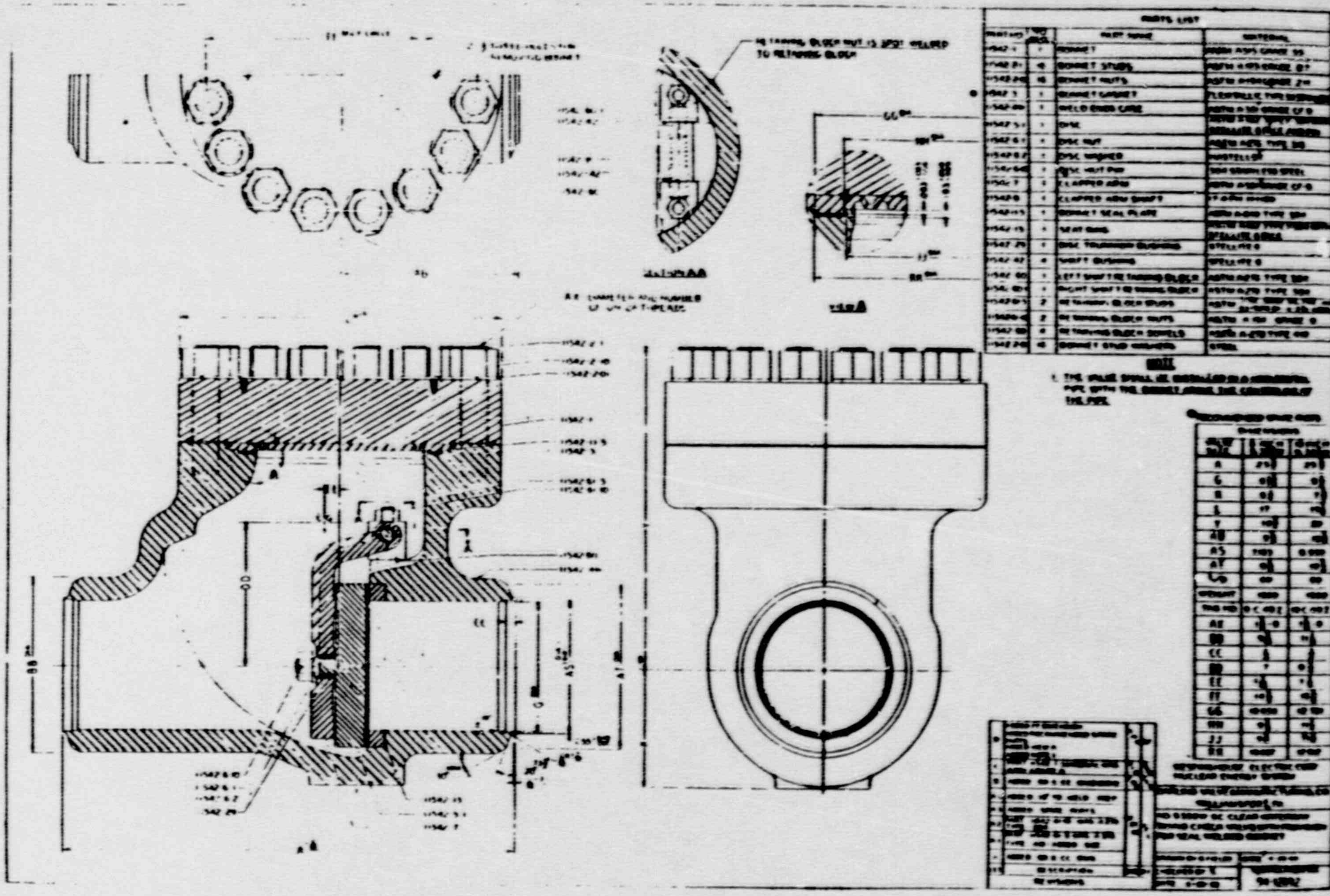
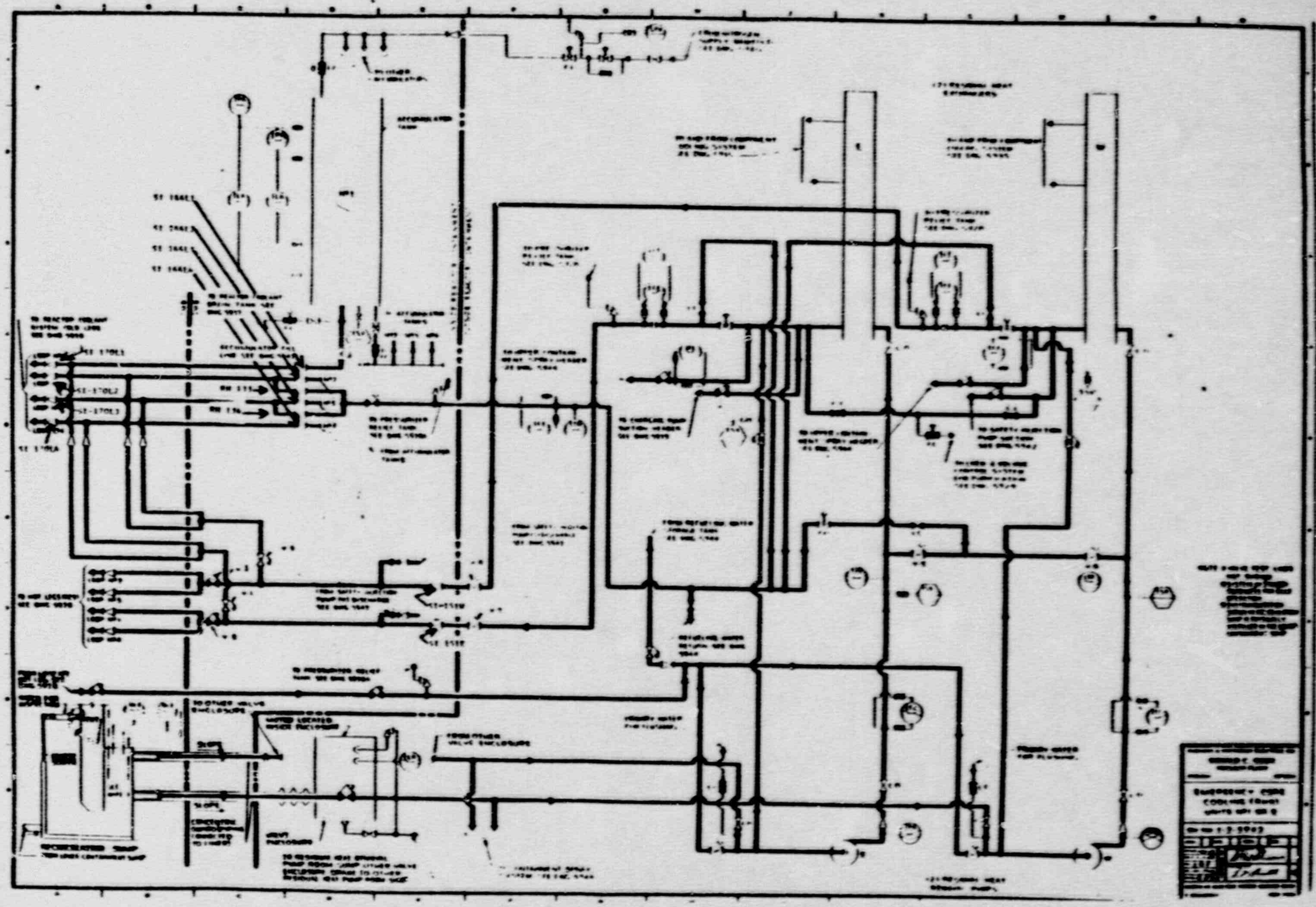


FIGURE 2: EMERGENCY CORE COOLING FLOW DIAGRAM



NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	1 OF 0 3

TITLE (4)

HPCI TURBINE THROTTLE VALVE BOLTS BROKEN DUE TO IMPROPER HEAT TREATMENT

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 2	1 9	8 7	8 7	— 0 0 3 —	0 1	0 6	2 4	8 7		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	VOLUNTARY
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
ROBERT BAKER, MAINTENANCE SUPERINTENDENT	3 1 5 342-3840

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	B J	T B E B	T 1 4 7	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) — X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

A maintenance inspection of the High Pressure Coolant Injection (HPCI) (EIIS Code BJ) Terry Turbine during the 1987 refueling outage had discovered broken bolts associated with the turbine throttle valves lifting beam. The broken bolts did not make the turbine inoperable because two dowel pins and two remaining bolts kept the lifting beam intact. Since the two remaining bolts were also cracked, an inoperable HPCI system could have occurred if this condition had not been discovered. The corrective action included replacement of the bolts, consultation with the vendor and metallurgical examination of the bolts which indicated failure by stress corrosion cracking of improperly heat treated bolts.

Failure of HPCI coincident with small loss of coolant accidents is within the range of accidents considered in Final Safety Analysis.

There have not been any similar LERs involving bolting failure due to stress corrosion cracking and improper heat treating.

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NRC Form 366 (9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	8 7	— 0 0 3 —	0 1	0 2 OF 0 3

The High Pressure Coolant Injection (HPCI) (EIIS Code BJ) Terry Steam Turbine received a complete tear down and internal inspection during the 1987 refueling maintenance outage. During this inspection, six (6) of the eight (8) bolts which hold the throttle valve lifting beam together were found broken. The remaining two (2) bolts were badly cracked. Two (2) dowel pins and the two (2) remaining bolts were maintaining the lift beam intact. If the lifting beam had not remained intact, turbine control would have been lost causing the HPCI system to be inoperable.

All beam bolting were replaced with specification conforming material. The vendor was on-site during the overhaul and vendor engineering was informed of the bolting failure. The cracked bolts were analyzed to determine the failure mechanism.

A metallurgical evaluation of three failed ASTM A193, Grade B6 (Type 410 stainless steel) bolts was conducted to establish the most probable cause(s) of the cracking of the bolts. Fractographic and metallographic examinations showed that the bolts failed by an intergranular failure mode, most likely stress-corrosion cracking. Chemical analysis confirmed that the chemical composition of the bolts met the material specification requirements. However, hardness measurements showed that the bolts were much harder than expected. This higher hardness is believed to have been a major contributor to the cause of failure. Laboratory tempering studies conducted at the minimum tempering temperature and time (1100 F for 1 hour) specified for the ASTM A193 Grade B6 bolts resulted in a drop in hardness of over 10 points Rockwell C, from the upper 30's for the as-received bolts to the mid-20s for the laboratory retempered bolts.

Copper was detected by electron dispersive X-ray analysis during examination of the thread root regions in the scanning electron microscope. It is believed that the copper may have come from a copper bearing antiseizure compound used on the bolts. The use of such compounds have been shown to cause localized pitting corrosion, which in turn, may have acted as the origin sites of the stress-corrosion cracks in Type 410 stainless steel. It is recommended that when bolts are heat treated as specified for ASTM A193, Grade B6 bolts the use of a lubricant such as a non-metal bearing petroleum jelly be used as an antiseizure compound. This recommendation for bolt lubricants will be incorporated in the HPCI maintenance procedures.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	8 7	— 0 0 3 —	0 1	0 3 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The Licensee will inspect the lift beam bolts during the next refueling outage scheduled in 1988.

Safety consequences and implications of failure of the HPCI system is within the envelope of accidents and transients considered in the Final Safety Analysis Report. Failure of HPCI coincidence with demand for the system as a result of a small loss of coolant accident when the plant is operating could require operation of the Automatic Depressurization System (EIIS Code AD) to reduce reactor pressure to within the range of Low Pressure Core Spray (EIIS Code BM) and Low Pressure Coolant Injection (EIIS Code BO).

There have not been any similar LERs involving bolting failure due to stress corrosion cracking and improper heat treatment.

James A. FitzPatrick
Nuclear Power Plant

Radford J. Converse

NewYorkPower
Authority

June 24, 1987
JAFP 87-0503

United States Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

REFERENCE: DOCKET NO. 50-333
LICENSEE EVENT REPORT: 87-003-01

Dear Sir:

Enclosed please find referenced Licensee Event Report in accordance with 10CFR50.73.

If there are any questions concerning this report, please contact Mr. Robert Baker at 315-349-6201.

Very truly yours,

RADFORD J. CONVERSE

RJC:RB:nan

CC: USNRC, Region I (1)
INPO Records Center, Atlanta, Ga. (1)
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1/1