ACCELERATED DISTRIBUTION DEMONSTRATION SYSTEM

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:9103050379 DOC.DATE: 90/12/31 NOTARIZED: NO DOCKET #
FACIL:50-331 Duane Arnold Energy Center, Iowa Electric Light & Pow 05000331
AUTH.NAME AUTHOR AFFILIATION
MINECK,D.L. Iowa Electric Light & Power Co.
RECIP.NAME RECIPIENT AFFILIATION

SUBJECT: "1990 Annual Rept of Facility Changes,Tests,Experiments & Safety & Relief Valve Failures & Challenges." W/910228 ltr.

DISTRIBUTION CODE: IE47D COPIES RECEIVED:LTR 1 ENCL 1 SIZE: 70
TITLE: 50.59 Annual Report of Changes,Tests or Experiments Made W/out Approv

NOTES: See Reports

	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL
	PD3-3 LA	1	0	PD3-3 PD	5	5
	HALL,J.R.	1	0			
INTERNAL:	ACRS	6	6	AEOD/DOA	1	1
	AEOD/DSP/TPAB	1	1	NRR/DLPQ/LHFB11	1	1
	NRR/DOEA/OEAB11	1	1	REG FILE 02	1	1
	RGN3 FILE 01	1	1			
EXTERNAL:	NRC PDR	1	1	NSIC	1	1

R I D S / A D D S

R I D S / A D D S

NOTE TO ALL "RIDS" RECIPIENTS:

PLEASE HELP US TO REDUCE WASTE! CONTACT THE DOCUMENT CONTROL DESK, ROOM P1-37 (EXT. 20079) TO ELIMINATE YOUR NAME FROM DISTRIBUTION LISTS FOR DOCUMENTS YOU DON'T NEED!

TOTAL NUMBER OF COPIES REQUIRED: LTTR 21 ENCL 19

10 CFR 50.59(b)

Iowa Electric Light and Power Company

February 28, 1991
NG-91-0374

Dr. Thomas E. Murley, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-137
Washington, DC 20555

Subject: Duane Arnold Energy Center
Docket No: 50-331
Op. License No: DPR-49
1990 Annual Report of Facility Changes, Tests, Experiments, and Safety and Relief Valve Failures and Challenges
File: A-118e

Dear Dr. Murley:

In accordance with the requirements of Appendix A to Operating License DPR-49, 10 CFR Part 50.59(b), and NUREG-0737 (Item II.K.3.3), please find enclosed the subject report covering the calendar year 1990. In addition, please note that we made no changes to the DAEC Fire Plan in calendar year 1990.

Please contact this office if you have any questions regarding this matter.

Very truly yours,

Daniel L. Mineck
Manager, Nuclear Division

DLM/CJR/pjv+

cc: C. Rushworth
L. Liu
L. Root
R. McGaughy
S. Sands (NRC-NRR)
A. Bert Davis (Region III)
NRC Resident Office
Commitment Control 900045, 900046

IE47
11

50-331 DUANE ARNOLD

1990 ANNUAL REPORT OF FACILITY CHANGES, TEST , EXPERIMENTS, & SAFETY & RELIEF VALVE FAILURES & CHALLENGES.

REC'D W/LTR DTD.02/28/91....9103050379

SECTION A - PLANT DESIGN CHANGES

This section contains brief descriptions of and reasons for plant design changes completed during the calendar year 1990 and summaries of the safety evaluations for those changes, pursuant to the requirements of 10 CFR Part 50.59(b).

The basis for inclusion of a Design Change Package (DCP) in this report is site closure of the package at the Duane Arnold Energy Center (DAEC) in the calendar year 1990. It is noted that portions of some DCPs listed were partially closed in previous years.

DCP 1072 Radwaste Conveyor Sump Modification

Description and Basis for Change

The Radwaste Conveyor Sump System had a history of fluid transport problems. Although the original sump pumps were not designed for slurry service, the pumps were required to handle a mixture of resin and water due to the requirement to solidify resin. These conditions resulted in the rapid deterioration of the pumps. Insufficient slurry velocities, associated resin plugging problems and increased radiological exposure to operating personnel resulted.

In order to resolve these problems, DCP 1072 installed two sump pumps, automatic condensate bearing flush water to each pump, and an automatic sparger system initiated by high sump level and terminated by a timer or high-high level. This DCP also modified existing piping in the conveyor pit to prevent plugging and replaced the existing pump discharge piping and valves.

Summary of Safety Evaluation

This modification involved the replacement of the original radwaste conveyor sump pumps with pumps having greater head and capacity to increase discharge piping velocities in order to prevent plugging. The installation of the sump sparging system within the sump did not change the function of the sump discharge piping. The sparging system was provided to prevent plugging of the discharge piping by mixing the sump prior to discharging, thus increasing the sump's overall reliability. The addition of automatic condensate bearing water will prevent bearing failure and thus increase pump overall reliability.

This design change increased the reliability of the conveyor sump system. System function remained the same, although system capabilities were enhanced.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1309 Install Neutron Shielding on Drywell Equipment Hatch

Description and Basis for Change

The shield door for the drywell equipment hatch was a steel shell filled with lead shot. This provided good shielding for the gamma component of the drywell radiation field, but was a poor neutron shield. The area outside this door was occupied by a supplemental shield of concrete blocks and still required posting as a neutron radiation area. This design change installed a neutron shielding sheet on the outside of the existing door, so that the area could be used for general activities without being posted as a neutron area. The neutron shielding is a silicone foam sheet filled with boron carbide attached to the outside of the door. The high neutron cross section of the boron provides an efficient attenuation of the neutrons that are streaming out of the door.

Summary of Safety Evaluation

The material is not relied upon nor will it affect the performance of any action under accident conditions. The material did not increase the fire hazard loading in the area. Any structural failure of the material or its adhesive would result in its falling harmlessly to the floor. Any seismic effects due to the increased mass are insignificant compared to the previously evaluated mass of the lead shield doors. The shielding is not addressed in Technical Specifications.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1312 Cardox Fire Panel Modification

Description and Basis for Change

This package installed a switch in the Zone Indicating Unit (ZIU-2), just outside the Cable Spreading Room, in order to eliminate a lifted lead operation during the performance of a surveillance test procedure (STP). The switch accomplishes the same function as lifting the lead in the Fire Detector Location Panel.

This modification also installed a voltmeter at control panel 1C428 to check the CO_2 System DC power. The existing voltmeter had been mounted on the CO_2 System battery charger which was replaced by a 125 VDC system.

Summary of Safety Evaluation

This modification ensured personnel safety and provided a means for checking the CO_2 System DC power. Checking the CO_2 System for DC power will help to ensure that the CO_2 System is operational.

This modification corrected a relay timing problem within the Cardox System control panel. This restored the system's function as it was originally designed.

Any malfunction of equipment installed in this package would only cause a loss of indication from the system. The switch malfunctioning would mean that no indication would be given of exactly which detector tripped inside the Cable Spreading Room. The detector would still give the alarm. The malfunctioning of the meter would cause no problem to the CO_2 system.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1317 <u>Replace River Water Pump Bowls</u>

<u>Description and Basis for Change</u>

The existing River Water Supply (RWS) pump bowls and impellers had deteriorated to the point where they would soon have needed to be replaced. The manufacturer of the existing pump bowl assemblies, Aurora, is no longer a qualified vendor for nuclear code parts.

This modification involved the replacement of the RWS pump bowl assemblies with assemblies manufactured by a pump manufacturer other than the original vendor. A run-time meter was also installed on each pump, and pressure and flow test instrumentation was added to the screen wash pumps. Additional modifications included installation of vibration probes, new type stuffing box packing seals, and stuffing box packing replacement.

<u>Summary of Safety Evaluation</u>

These modifications allowed the pumps to perform their intended function to at least the original degree of reliability. The modification did not introduce any new failure modes to the system and allowed the system to provide the required amounts of water to the RHRSW and ESW Systems.

The new pumps meet or exceed all requirements of the original pumps as outlined in the design specifications. All materials were equivalent to those used on the original pumps with the exception of the impellers and bowls. These new pumps are stainless steel, instead of the original bronze and carbon steel, since stainless steel is more suitable for the abrasive environment the pumps experience.

Addition of the run-time meters had no significant impact on the seismic qualification of the 480V load center in which they were mounted. Electrical isolation was achieved by using an independent power supply and circuit breaker auxiliary contacts. Addition of the pressure and flow test instrumentation on the screen wash pumps had no impact on plant safety.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1340 HVAC Ductwork Penetration Modification

Description and Basis for Change

In October 1983, the NRC issued Information Notice 83-69, "Improperly Installed Fire Dampers at Nuclear Power Plants." In response to this notice, field inspections were performed on DAEC fire dampers. Fire damper evaluations were subsequently generated for all penetrations at the DAEC. The evaluations determined that physical modifications were required for several penetrations.

DCP 1340 involved work on fifty existing HVAC penetrations containing fire dampers. There were four types of modifications: retention of dampers; closure of penetrations; addition of duct access doors; and, disabling of dampers. Five new fire dampers were installed. Also, a domestic water line was relocated to avoid interference with damper modifications.

Summary of Safety Evaluation

Modifications were within the same design criteria requirements used in the original plant design and considered the seismic impact, effect of reduced air flow due to additional air pressure drop through new fire dampers, thermal environment, and fire protection requirements. This modification corrected damper installation deficiencies and therefore ensured that ductwork fire barrier penetrations protecting safety-related areas can be expected to remain intact during design basis fires of standard duration and perform their proper function.

Installation of fire dampers and access doors did not alter the function or method of operation of any safe shutdown system.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1344 Replacement of Radwaste Floor Drain Demineralizer 1T-94 and Waste Demineralizer 1T-215, 1T-68 Resin Tank Bypass

Description and Basis for Change

An inspection of radwaste demineralizer tank 1T-94 revealed that the tank's rubber lining was deteriorating below the resin fill level. The rubber was separating from the tank wall in strips and there was evidence of corrosion on the carbon steel tank. This design change replaced the old radwaste demineralizers 1T-94 and 1T-215 with new stainless steel demineralizers.

The design change also provided a new cross-tie path that allows spent resin tank 1T-68 influent to be sent to waste sludge tank 1T-62A. The spent resin tank influent is received from the floor drain and waste demineralizers. This waste stream can now be

directed by a remotely-operated valve to the waste sludge tank. The new cross-tie piping tees into an existing 8 inch inlet line (fuel pool demineralizer filter backwash) to the waste sludge tank.

Summary of Safety Evaluations

The change-out of tanks 1T-94 and 1T-215 was a "like-for-like" modification in regards to tank geometry, function, and location. The new tanks are stainless steel which enhances operability and reduces maintenance and the chance for malfunction. The new tanks have welded attachments instead of flanges, which poses no new possibility of an accident. Modifications performed by this DCP did not affect safety-related equipment and did not affect the function or operability of safety-related systems or components. This modification enhanced our ability to collect, process and package solid wastes in a safe manner. This will reduce the amount of radiation exposure during the life of the plant, thus improving the ALARA program.

No anticipated malfunction of the cross-tie valve or piping such as a failure in valve operation or a valve/piping pressure boundary breach can be expected to affect any of the design basis accident events as listed in UFSAR Chapter 15. No anticipated modification malfunction can lead to a radioactive release from a subsystem or component in excess of the requirements of 10 CFR Part 20 or lead to the loss of habitability of the control room.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1382B Chemical Addition to the RHR SW System

Description and Basis for Change

During refuel outages when Residual Heat Removal (RHR) heat exchanger maintenance is performed, corrosion of the carbon steel channel and channel heads has been observed. The corrosion was of a general nature and had likely been occurring since the heat exchangers were put into service. The heat exchangers remain idle for long periods of time except for periodic testing and RHR operation during reactor shutdown, allowing water to stagnate in the tube side of the exchanger. Mud and slime deposits have been observed in the exchanger head that indicate the corrosion is caused by biological growth and sedimentation in the stagnant water.

It was recommended that a sodium hypochlorite system be installed for the RHR Service Water (RHRSW) system to prevent biofouling and a corrosion inhibitor be added to the RHRSW to reduce heat exchanger corrosion. DCP 1382A installed the corrosion inhibitor injection system and the outage portion of the sodium hypochlorite system. DCP 1382B installed mechanical and electrical components necessary to complete the RHRSW chlorination system.

A new injection pump was installed in the sodium hypochlorite tank room to provide sodium hypochlorite injection for the RHRSW and Emergency Service Water (ESW) systems. The suction for the new pump ties into the hypochlorite feed line from tank 1T-255 downstream from the General Service Water (GSW) hypochlorite pump. The new pump discharges into a mixing tee with dilution flow provided from the GSW system. Controls for the new pump and valves were added to a new pumphouse panel located in the 'B' RHR pump room. Additionally, 1T-256 was modified with tank baffles and a relocated mixer. A sample valve was added to GSW piping and the impellers for the booster pumps 1P-121A/B were decreased in size.

The RHRSW chlorination system is manually started, and manually stopped when not required. An interlock is provided to stop the sodium hypochlorite injection pump and close all valves when a high chlorine level exists in the circulating water blowdown. The RHRSW chlorination system must be manually restarted after the high chlorine condition is cleared. An additional interlock is provided to prevent operation of sodium hypochlorite injection pump 1P-280 if dilution water flow is not available.

Summary of Safety Evaluation

This modification did not affect the method of operation or safety function of the RHRSW and ESW systems. No new failure modes of the RHRSW and ESW systems were introduced. The injection system utilizes the existing sodium hypochlorite supply. The new piping does not physically tie into the RHRSW and ESW systems at any point. The new piping was seismically supported to maintain pipe integrity, and thus prevent any impact on the pumps.

The increase in the chloride concentration is not large enough to cause a significant increase in the probability of stress corrosion cracking. In addition, the use of sodium hypochlorite will result in a slight increase in pH which will reduce the corrosive environment. Therefore, the addition of the hypochlorite will not degrade the stainless steel RHR heat exchanger tubing or other ESW components which contain copper alloy tubes. The chemical injection system will decrease the amount of biological fouling on the tube side of the heat exchangers. This eliminates an existing mechanism for potential failure of the RHR heat exchanger tubing. If a tube did fail, Technical Specifications regulate the chemistry of the reactor coolant water. Any leakage of chemicals through the RHR heat exchanger tubing which affects reactor coolant water chemistry would be detected and the appropriate Technical Specification action would be taken.

The new control valves fail closed upon loss of air. Thus, a failure of the air supply will not result in loss of isolation capability. Loss of power will terminate chlorination because the pump and control valves share the same power supply.

Chlorination will be performed during normal surveillance testing of the RHRSW system; thus, chemical injection will not provide an additional challenge on the safety system.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1418 <u>480 Volt Breaker Replacement</u>

<u>Description and Basis for Change</u>

DCP 1418 replaced five 480 volt breakers in each of the Essential Load Centers 1B3 and 1B4 with an upgraded model of the same breaker. Each of these ten breakers had been equipped with a mechanical overcurrent trip device which had become worn due to age, repeated rebuilding and testing. This DCP replaced these breakers with new "state-of-the-art" breakers having solid state trip devices in place of the mechanical ones.

This modification also removed the instantaneous trips from breakers 1B-302, 1B-304, 1B-402, and 1B-404. The instantaneous trips of breakers 1B-301, 1B-303, 1B-401, and 1B-403 had been removed during the 10 CFR Part 50, Appendix R required modifications. It was necessary to remove these trips in order to achieve proper breaker coordination.

<u>Summary of Safety Evaluation</u>

The solid state trip units perform the same function as the mechanical trip units, but are more reliable. The solid state trip unit did not change the form, fit, or function of the breaker. The solid state trip units have been tested and qualified to the latest standards. Upgrading these breakers ensures that these breakers will continue to function as originally intended.

No failure modes of the circuit breaker or any other equipment were changed by upgrading the trip units of these circuit breakers. The probability of occurrence of a malfunction was not increased because the solid state trip units are more reliable and have better repeatability. The solid state trip units do not have moving parts that are subject to wear. Also, the solid state trip units can be set up for a broader range and more defined trip curves which greatly enhances breaker coordination efforts.

Removing the instantaneous overcurrent trips from the load center breakers allows the motor control center breaker time to clear a short circuit fault before a trip is initiated on the load center breaker. This prevents unnecessary trips to the load center breaker on downstream faults. The short-time trip is as reliable as the instantaneous trip and will clear a short circuit fault in time to prevent equipment damage.

The short-time overcurrent trip increased the fault current clearing time of the breaker from 0.05 seconds to a maximum of 0.5

seconds. This maximum clearing time is fast enough to prevent overheating of cabling due to a short circuit fault, and is also below the time delay settings of any associated 480 volt undervoltage devices. This is necessary to prevent unwanted undervoltage trips.

Increasing the short-circuit clearing time of the circuit breaker decreased the maximum instantaneous current interrupting capacity of the breaker from 30,000 amps to 22,000 amps. This was not a concern because the maximum fault current expected at 1B3 or 1B4 is 20,781 amps based upon a bolted short at 1B3 or 1B4 with all equipment running to support 100% power operation, which are higher loads than during accident conditions.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1438 Sprinkler/Deluge System Test and Inspector Test Drain Modification

Description and Basis for Change

This change was initiated to reduce the volume of water discharged to Radwaste and to prevent overfilling floor drains during sprinkler/deluge surveillance testing. Modifications to inspector test connections will facilitate future incorporation into the surveillance testing program as recommended by Authorized Nuclear Insurers.

The modification was mechanical in nature and involved installation of drain piping for several sprinkler/deluge systems.

Summary of Safety Evaluation

This modification only affected drain piping for sprinkler/deluge system testing. Safety-related systems were not modified. There were no changes to the method of operation or function of equipment important to safety.

New piping was routed in areas that already contained drain piping and was supported as required to prevent adverse impact on equipment during a seismic event. Because drain piping is normally depressurized, it did not represent a new source of flooding that could affect important-to-safety equipment. Drain lines are only pressurized during system testing when personnel will be present to notice any failures.

Because the amount of water discharged to radwaste during testing was reduced, this DCP decreased the challenges to the Radwaste system.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1443 Cable Upgrade for MO-2312

Description and Basis for Change

Information Notice 89-11 identified potential problems resulting from DC MOVs not developing rated torque because of the failure of the original cable sizing calculations to include the proper current values and cable resistances. An earlier NRC Bulletin, 85-03, identified potential problems of MOVs failing to open or close as required due to improper torque switch settings.

Evaluations showed that DC motor-operated valve MO-2312 (HPCI Isolation Valve) may not have operated properly under degraded voltage conditions because of excessive voltage drop in the power cables routed from the DC motor control center (MCC) to the valve operator. This design change installed 2 #4 AWG power cables to the DC MOV MO-2312. The 4 existing #8 AWG power cables were paralleled and utilized with the 2 #4 AWG cable to supply power to MO-2312. This design change increased motor terminal voltage by reducing voltage drop, thus increasing motor torque by increasing current to the motor.

Summary of Safety Evaluation

The function and method of operation of this valve were not affected by the modification. Valve initiating signal and valve opening/closing time were not adversely affected by these modifications. The modifications performed by this DCP improved the capability of the existing MOV by increasing the available voltage at the motor terminals. The modifications performed by this DCP did not affect the use of the HPCI system to mitigate the consequences of analyzed accidents. Rather, the new cables enhanced valve response under degraded voltage conditions.

The replacement of the power cables was performed using criteria as stringent or more stringent than the original installation criteria and considered seismic impact, environmental conditions, fire protection requirements, and the effect of cable additions on existing cables routed in the tray.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1447 Residual Heat Removal Valve Interlocks

Description and Basis for Change

Inadvertent draining of the reactor vessel to the suppression pool has occurred on several occasions at Boiling Water Reactors (BWRs). These events occurred during improper valve line-ups in the Residual Heat Removal (RHR) system, during the refueling and shutdown modes of reactor operation. Rapid draining of the reactor vessel then occurred.

Rapid and uncontrolled draining of the reactor vessel has the potential to uncover fuel in the reactor vessel. If this type of event occurred while the reactor vessel head and gate between the reactor cavity and the spent fuel storage pool were removed, extremely high radiation dose rates could occur on the refueling floor due to loss of water in the spent fuel storage pool. If a vessel draining occurred during a refuel outage when irradiated fuel was being moved between the vessel and the fuel storage pool, it would be possible to uncover a fuel bundle being transported by the bridge. Fuel cladding failure and fission product release due to overheating can occur within one to two hours, depending upon decay heat generation rate.

This design change provided interlocks between the suppression pool suction valve and the shutdown cooling suction valve on each pump such that neither valve can be opened if the other is not fully closed. It also provided an interlock between the shutdown cooling suction valve on each pump and the full-flow test return valve to the torus. The addition of these interlocks eliminated the possibility of both valves being open at the same time. Thus the possibility of an inadvertent draining of the reactor vessel was reduced with this modification.

Summary of Safety Evaluation

The RHR valve interlocks were designed to reduce the possibility of an inadvertent draining of the reactor vessel. An inadvertent draining of the reactor vessel to the torus is a loss-of-coolant accident (LOCA). An accident analysis of a loss-of-coolant accident is contained in Chapter 15 of the UFSAR. The possibility of an inadvertent draining was reduced with the installation of the RHR valve interlocks. If a vessel draining occurred during a refuel outage when irradiated fuel was being moved between the vessel and the fuel storage pool, it would be possible to uncover a fuel bundle being transported by the bridge. A fuel assembly drop is analyzed in the UFSAR. The radiological exposure to the general population of this accident bounds the potential of uncovering fuel if a vessel draining occurred. With the installation of the RHR valve interlocks, the possibility of the vessel draining during the moving of fuel bundles was reduced.

The installation of interlocks did not change the design intent of any modes of the RHR system. When an RHR automatic initiation signal is received, the interlocks will not prevent safety systems from functioning. The valve interlocks allow both valves to be closed at the same time but neither valve can be opened with the other open. No major or minor modes of the RHR system procedures use both valves open at the same time. The addition of the interlocks did not affect any automatic initiation signals received from these modes. If a LPCI initiation occurs in shutdown cooling, the system does not automatically realign itself. The operator is required to close the shutdown cooling suction valves and then open the torus suction valves. This modification ensures

procedural compliance such that the operator closes the shutdown cooling suction valves prior to opening the torus suction valves.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1448 Long-Term DCRDR Modifications to 1C-06

Description and Basis for Change

This design change package performed design modifications to Control Room Panels 1C-06 and 1C-04 to correct human engineering deficiencies identified in the DCRDR summary report for this panel.

The Emergency Service Water (ESW) flow indicating controllers were replaced. The River Water makeup flow indicators, radwaste dilution flow indicator and the General Service Water discharge header pressure indicator were relocated. Also, the non-functional lights for the River Water supply pumps were removed.

The ranges of the Condensate Circulating Water, ESW, and Reactor Water Cleanup (RWCU) pump ammeters were modified to allow indication of the long term trip setpoints. The scale for the Recirculation pump voltage indicators was replaced to be consistent with actual design characteristics and acceptable human engineering scale markings.

Control panel label and documentation for handswitch control for Reactor Building Closed Cooling Water (RBCCW) valves MO-4841A and MO-4841B were changed to improve functional descriptions and correct component identification numbers. A conductivity recorder was replaced with a new recorder. Well Water pumps A, B, and C HI/LO Flow alarms were interlocked with the associated pump run logic to activate the alarm only during alarm conditions.

Summary of Safety Evaluation

The modifications did not change the original design intent or function of the instruments, handswitches, or controls. In fact, these modifications reduced the probability of human error and inadvertent operation associated with the use of control indications.

Where used, replacement components were those widely applied in the utility and control industries, with appropriate equipment qualifications criteria applied. Existing design criteria for electrical and physical isolation and separation was adhered to and modifications acceptance testing was performed as required to ensure proper installation and operation.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1449 DCRDR Replacement of Multi-point Recorders and 1C-34 Annunciator "Blackboard" Modifications

Description and Basis for Change

This design change package performed modifications to panels 1C-02, 1C-20, 1C-21, 1C-31, and 1C-34 related to replacement and relocation of multi-point recorders and interlocking annunciator inputs to ensure alarms are only actuated during conditions indicative of actual component or system off-normal conditions. All alarm and switch functions continue to be provided by the new recorders. The modifications corrected human engineering deficiencies identified in the DCRDR summary report, the annunciator study, and other identified problems.

The replacements were necessary as some of the existing multi-point recorders were obsolete, and their recorder traces had become almost unreadable. One recorder was inoperable with no available repair parts. The replacement recorders are more accurate, reliable and versatile. Alarms on 1C-34 were interlocked with the appropriate system or component conditions so that the alarm will be energized only during actual alarm conditions.

Summary of Safety Evaluation

This modification replaced obsolete recorders whose recorded traces had become almost unreadable. The new recorders are state-of-the-art and enable the operator to determine the instantaneous value of a recorded parameter via an LCD digital readout which scans through the operating channels. This, coupled with the increased accuracy of the new recorders, results in a better implementation of the recorder's intended function. Alarm and switch functions continue to be provided by the recorders with increased accuracy.

No system functions or characteristics were changed. The new recorders presented no new failure modes. All structural modifications associated with recorder installation were determined to have no effect on the seismic integrity of the associated panel.

This modification interlocked annunciators to system or component conditions so that the alarm function will be energized only during actual alarm conditions. This did not affect the system functions or characteristics. The annunciator logic was reviewed to assure that the modified logic is consistent with its original intent. The modification improved operator interaction with the annunciator system by providing the alarm function only during conditions when it is applicable.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1450 Long-Term DCRDR Enhancements for 1C-04

Description and Basis for Change

This design change package consisted of design modifications to the Reactor Support System panel, 1C-04. Minor changes to other panels were performed in the plant and control room. These modifications were designed to correct Human Engineering Deficiencies (HEDs) identified in the DCRDR Summary Report and identified Engineering Work Requests (EWRs).

The following modifications were accomplished with this package:

- Fuel Pool water level indication was added to panel 1C-04 and panel 1C-65.
- Skimmer Surge Tank level indication was provided adjacent to the new Fuel Pool level indicator on panel 1C-04. Local indication and an input to the computer of skimmer surge tank level were also provided.
- Recirculation Pump Mini-Purge valve controls were relocated above their respective Recirculation pump controls on the 1C-04 benchboard.
- Annunciator Acknowledge and Test pushbuttons on Panel 1C-04 were relocated. The previous location was awkward and inconvenient because the pushbuttons were located across the benchboard and in the corner of the vertical panel.
- The square root converter for RCIC pump discharge flow and the power supply for RCIC turbine test were relocated to panel 1C-19.
- New deviation meters were added to the Recirculation Speed Controllers to provide scoop tube position deviation for use when unlocking the scoop tubes.
- MSIV drain valve controls were rearranged on panels 1C-03 and 1C-04 to be consistent with MSIV handswitch arrangement.
- RCIC Turbine Stop Valve indicating lights using valve stem position limit switches were added to panel 1C-04.
- Recirculation Lube Oil Pumps had their control circuit modified to deenergize their indicating lights when their respective supply breaker is open.
- Heat-up and Cool-down rate displays were implemented on the existing PPC Computer. The heat-up/cool-down screens are an aid for the operator/STA during all heat-ups and cool-downs.
- Existing spare contacts of override switches were used to provide two sets of parallel contacts to override their respective functions.

- RHR Steam Condensing controls and indications on panel 1C-04 were removed.

- A time delay was added to the HPCI/RCIC suction swap on low Condensate Storage Tank level.

- Fuel zone level indicators have transmitters from the same reference leg which is misleading to operators since these are the only two fuel zone level indicators. This DCP used the signal from LT-4565C which is recorded on LR-4565A pen 2 and used it to indicate as LI-4565C vice LI-4565A. LI-4565A ceased to exist. The signals from LT-4565A and LT-4565C continue to be recorded on LR-4565A pen 1 and pen 2 respectively. In addition, Condensing Chamber numbers were added to all control room RPV level indicators.

- The scram indicating lights on panels 1C-15 and 1C-17 were physically moved approximately two inches directly above their current location.

- Various overrides were installed for use as required by Revision 4 of the Emergency Operating Procedures (EOPs). These pertain to the following ten modifications:

  - HPCI High Torus Water Level Transfer Defeat.
  - RPS Auto Scram Logic Trip Defeats.
  - Drywell Cooling Isolation Defeats.
  - MSIV and Main Steam Line Drain Isolation (Group 1) Defeats.
  - Reactor Feed Pumps (RFPs) High RPV Level Trip Defeat.
  - HPCI Steam Line Isolation Defeat.
  - RCIC Steam Line Isolation Defeat.
  - Drywell/Torus Vent and Purge Isolation Defeat.
  - RHR Discharge to Radwaste Isolation Defeat.
  - RWCU Low RPV Level, RWCU Area Temperature Isolation and SBLC override Defeat.

Summary of Safety Evaluation

The addition of Fuel Pool water indication to panels 1C-04 and 1C-65 required the installation of an ultrasonic sensing element mounted in a stilling well in the Fuel Pool. No conceivable event can occur as a result of the introduction of a stainless steel stilling well into the fuel pool which is not bounded by the analysis of refueling accidents described in the UFSAR.

Skimmer Surge Tank level provides one of the first indications that Fuel Pool water level is trending in one direction or another.

Providing this indication to the Control Room Operators will inform them of developing conditions.

The relocation of the mini-purge valve controls closer to their associated components should improve operator performance.

Moving the Annunciator Acknowledge and Test switches placed them in a position which is much more accessible to the operator than their previous location. This will reduce the need to lean over the panel to reach the controls.

The relocation of the square root converter for the RCIC pump discharge flow and the power supply for the RCIC turbine governor test from 1C-04 to 1C-19 will not affect operator actions.

The addition of deviation meters reduces the probability of inadvertent recirculation pump speed changes when unlocking the scoop tube. Operators now have direct indication of the deviation between the demanded position of the positioner and its actual position. In addition, the MG sets will lock-up if a large positive signal is sent to the scoop tube positioner except during generator startup. This modification will reduce the possibility of a recirculation pump runaway as described in UFSAR Chapter 15. The potential speed changes resulting from unlocking the scoop tube are of a lesser magnitude than those described in UFSAR Chapter 15. The addition of the amber light adjacent to the controls provides direct visual indication to the operator that the scoop tube is locked.

The relocation of the MSIV drain valve controls is consistent with the arrangement of the PCIS Mimic panel and the existing MSIV valve control handswitch arrangement on panel 1C03 and 1C04. Existing design criteria for electrical and physical isolation and separation were adhered to and post installation/modification testing was performed as required to ensure proper installation and operation.

Direct RCIC Turbine Stop Valve position indication in the control room reduces the possibility of erroneous operations by providing actual valve status information instead of just motor position.

The deenergization of the indicating lights for Recirculation Lube Oil Pumps when their respective motor breaker opens conforms with the control room standard. This modification corrected an observed error.

The heat-up and cool-down information which is provided on the computer screen utilizes the same signals as panel instrumentation. This information provides the operator all calculated data in one convenient location.

The addition of parallel contacts for the override switches improved each switches' reliability.

The Steam Condensing mode of RHR is no longer used at the DAEC. This DCP de-energized valves in their isolation positions and removed controls to prevent inadvertent movement.

The time delay added to the HPCI/RCIC suction swap on low CST level was set at 2 seconds or less. With this time delay, an actual low level condition would remove an additional 115 gallons (maximum) from the CST with both systems pumping at rated flows prior to the start of the suction transfer. The low CST transfer setpoint corresponds to 10,000 gallons in the CST. The additional 115 gallons drawn from the CST during the time delay will not result in a noticeable decrease in suction pressure.

The display of Fuel Zone level from different condensing chambers by changing the inputs to existing Fuel Zone indicator LI-4565A and re-identifying this indicator as LI-4565C did not affect the probability or the consequences of an accident or malfunction of any equipment important to safety.

The scram lights on 1C-15 and 1C-17 were physically moved. The new placement of the lights meets all physical and electrical separation requirements.

The addition of keylock switches and indicating lights for EOP overrides provides for operator actions which are required procedurally during an emergency. Use of keylock switches prevents inadvertent operation having the potential to override automatic isolations. Lights provide indication that the associated switch is in the override position. The only time the switches will be placed in the override position, other than testing, will be in the unlikely event that plant conditions would degrade beyond the specific conditions analyzed as part of the UFSAR. These actions were generically examined by the NRC staff as part of the BWR Owners' Group Emergency Procedure Guidelines review and were found appropriate for the extreme situations required by their use.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1451 <u>DCRDR Annunciator Modifications</u>

<u>Description and Basis for Change</u>

The following modifications were accomplished with this package:

- The existing annunciator horns mounted inside panels 1C-05 and 1C-07 were replaced with horns which have both volume and frequency adjustments.

- Annunciator windows were "prioritized" via a color coding scheme using red and blue color film inserts behind the annunciator windows.

- Annunciator window engravings were modified, as necessary, to be consistent with the actual annunciator signals.
- Annunciators were rearranged on panels 1C-03, 1C-04, and 1C-05.
- Two new annunciator light boxes were installed on panel 1C-14 to hold the MSIV-LCS alarms currently on 1C-35 and the alarms associated with the EOP overrides.
- The 30% power turbine stop valve closure and turbine control valve fast closure SCRAM bypass logic was modified to annunciate only when all channels of RPS are bypassed.
- Separate PUMP MOTOR OVERLOAD and PUMP TRIP alarms for the following pumps were combined into one overload/trip alarm per pump:

  Circulating Water Pumps

  Condensate Pumps

  General Service Water Pumps

  Reactor Recirc Pumps

  Control Rod Drive Pumps

  Core Spray Pumps

  Residual Heat Removal Pumps

  RHR Service Water Pumps
- The start logic for the Emergency Bearing Oil Pump was modified to provide power to the green light for HS-3151 on 1C-07 when the handswitch is in the STOP or PULL-TO-LOCK position.
- The REACTOR VESSEL HI PRESSURE RECORDER ALARM window was removed from 1C-05.
- A bypass switch was provided on 1C-06 to allow operators to conditionally inhibit the audible and visual alarms arising from feedwater heater levels. A bypass switch was provided on 1C-07 to allow operators to conditionally inhibit the audible and visual alarms arising from the moisture separator reheater drain tank levels and differential pressure. These inhibits are interlocked to function only when a full scram signal is detected and/or the turbine stop valves are closed and the handswitch is in BYPASS.
- At 1C-23, the TURBINE BLDG AUX HTG PUMP 1V-HP-20A/B LO FLOW alarm, the REACTOR BLDG AUX HTG PUMP 1V-HP-10A/B LO FLOW alarm, and the MAIN HOT WTR LOOP CIRC PUMPS 1P-52A/B LO FLOW alarm were interlocked with the respective handswitches such that the alarm will not activate when both pump handswitches are in the STOP position. A time-delay relay was used for the

interlock such that the alarm will not be active until the pump is up to speed.

- At 1C-23, the PLANT HEATING HX 1E-17 LO TUBE/SHELL ΔP ISOLATION alarms were interlocked with the Auxiliary Heating Circulating Water pumps and heat exchanger 1E-17 inlet and outlet valve position to override the alarm when both pump handswitches are in the STOP position and both inlet and outlet valves are closed.

- At 1C-23, the AUX BOILER FEED PUMPS 1P-54A/B LEAD PUMP OUT OF SERVICE and AUX BOILER 1S-61 TROUBLE alarms were interlocked with the handswitches such that the alarms will not activate when the Auxiliary Heating System is not in service.

- The MAIN INTAKE HEATING CIRC PUMPS 1V-HP-12A/B LEAD PUMP TROUBLE alarm was interlocked with the handswitches such that the alarm will not actuate when both pump handswitches are in the STOP position.

- At 1C-24, the DRYWELL INSTR N2 SUPPLY CV-4371A IN BYPASS alarm was removed.

- The annunciator horns for 1C-40 and 1C-40A were consolidated.

Summary of Safety Evaluation

The existing annunciator horns were single frequency, fixed volume horns. These modifications allow the horn frequencies to be adjusted to make each sound unique. A volume adjustment is provided to allow the horn volume to be changed with changing ambient noise levels as suggested by human factors principles. These adjustments enhance the operator's ability to more quickly identify and locate the source of an alarm.

Prioritization of annunciator windows with color did not change the annunciator system function or characteristics. Use of colored alarm windows allows the operator to more quickly discern which alarm conditions in a multi-alarm situation should be given "priority." These changes enhanced the operator's ability to respond to multi-alarm situations.

Providing annunciator window engravings that are consistent with the actual signals did not change the annunciator system function or characteristics. Accurate window engravings enhance the operator's ability to characterize off-normal conditions and respond in a timely manner.

Rearrangement of the annunciator windows on 1C-03, 1C-04, and 1C-05 did not change the annunciator system function or characteristics. Moving annunciators to the panels which house the associated indications and controls was an inherent location aid and enhanced the operator's ability to respond to the alarms in a timely manner.

The addition of annunciator light boxes on 1C-14 did not change annunciator system function or characteristics. The new light boxes did not degrade the seismic integrity of the panel or mounted components. The vacated windows will be available for future annunciator expansion.

Modifying the 30% power SCRAM bypass logic to alarm only when all channels of the associated RPS signal are bypassed improved the information provided the operator. When the alarm is activated, the bypass is complete. In the old configuration, with the alarm contacts in parallel, only one channel of RPS was necessary to activate the alarm. In such a state, the alarm could signal that the SCRAM signal is bypassed, yet two of the remaining three channels of RPS could give an unexpected SCRAM on either turbine stop valve closure or turbine control valve fast closure. This logic modification provided the operator with unambiguous indication that such a SCRAM is bypassed, and therefore decreased the probability of an inadvertent SCRAM.

The combination of pump overload and trip alarms did not adversely affect the operation of either the pumps or their respective systems. Although the alarms are consolidated, adequate information is available for the operator to quickly determine whether the pump has tripped or is in a pre-trip overload condition via the individual pump ammeters.

The Emergency Bearing Oil Pump logic modification did not affect the function or operative characteristics of the pump or turbine lube oil system. The logic modification will make the indication consistent with other control room handswitches. This will aid the operator in monitoring pump status.

The REACTOR VESSEL HI PRESSURE RECORDER ALARM window was redundant to a neighboring alarm. Removing this redundant alarm did not affect the function or characteristics of any reactor pressure indication or recording device.

During startup, heater levels and drain tank levels fluctuate wildly, producing alarms which must be acknowledged both when they come in and when they clear soon after. These nuisance alarms divert the operator's attention from more important activities in order to maintain relative quiet in the control room. Interlocking the bypass to the turbine stop valve closure and a full SCRAM signal ensures these annunciator signals will be available when needed, while reducing operator distraction and work load during the periods when these alarms do not provide the operator with any significant information.

Interlocking the Turbine Building Aux Heating Pump, Reactor Building Aux Heating Pump, and Main Hot Water Loop Circ Pump, low flow alarms to the pump handswitches did not affect the system functions or characteristics. Having an alarm window lit when the pumps are shut down dilutes the effectiveness of the alarm when

one or both of the pumps are running. The alarm logic was analyzed and no adverse impact from this interlocking was found. It was further determined that this modification would be "transparent" to the operator, in that it makes the alarm function as designed, drawing attention to a situation where flow is expected, but inadequate flow is detected.

Interlocking the Plant Heating Heat Exchanger low differential pressure alarm to the heat exchanger inlet and outlet isolation valves and the circ pump handswitches did not affect the system function or characteristics. Low differential pressure warns that a potential radiation release path exists in the event of a heat exchanger tube leak. If the shell side of the heat exchanger is not at a higher pressure than the tube side, a tube leak would allow reactor cooling water into the plant heating loop. Low differential pressure sensed by either of two comparators results in the heat exchanger tube side being isolated. Low differential pressure is a normal condition when the main circulating pumps are not running. Therefore, if the circulating pumps are shut down and the heat exchanger is isolated, the alarm provides no meaningful information.

Interlocking the Aux Boiler alarms to the burner handswitch and the Main Intake Heating Circ Pump low flow alarm with the associated handswitches did not affect the systems' functions. Having an alarm window lit when the system is shut down dilutes the effectiveness of the alarm when the system is operating. The alarm logic was analyzed and no adverse impact from this interlocking was found. It was further determined that this modification will be "transparent" to the operator, in that it makes the alarm function as designed.

Removing the Drywell Instrument Nitrogen CV-4371A in Bypass alarm from 1C-24 did not affect the Nitrogen System function or characteristics. Consistent with the indication provided for other front-panel-mounted overrides and bypasses, the existing amber indicating light above the handswitch provides adequate indication of this off-normal condition.

Consolidating the alarm horns for the Fire Protection Panels reduced the number of unique tones which the operator must recognize, and did not affect Fire Protection System function or characteristics. The audible alert and revert signals for either Fire Protection panel required that the operator acknowledge the alarm in the same area.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1454 Degraded Voltage Modification

Description and Basis for Change

Essential Bus 1A3 and 1A4 are protected from low voltages by the Degraded Voltage Relays. Previously these undervoltage sensing relays operated to de-energize an intermediate relay, which then tripped the source circuit breakers for the essential bus. This action removed the source of degraded voltage from the essential bus and also started the Standby Diesel Generator (SBDG) to provide a source of power to that essential bus. This Degraded Voltage circuitry and the SBDG start circuit are powered from 125 VDC Control Power.

Two events could cause an essential bus to be de-energized - loss of all 125 VDC control power and inadvertent de-energization of Degraded Voltage circuitry.

To eliminate the occurrence of these two events the circuit was redesigned. The redesign changed the circuit logic from "de-energize to trip" to "energize to trip" logic. The modification retained the original characteristics that were used to describe these circuits to the NRC when they were installed by DCR 759. The normally open contacts of the undervoltage relays were changed to normally closed. A time delay relay was added to prevent a race condition between the undervoltage relays and the trip relay. The lens of the circuit status indicating light was changed from white to amber to indicate the condition of the trip relay. Auxiliary contacts from the circuit breakers still are used to monitor the position of the circuit breakers and to prevent load shedding from reoccurring once the circuit breakers have been tripped.

Summary of Safety Evaluation

The system still uses one-out-of-two-taken-twice for degraded voltage logic. The protective action trips the bus supply circuit breakers from the Start-up and Standby transformers and still starts the SBDG for the affected essential bus. The addition of a time delay relay was necessary to prevent a race condition between the voltage sensing relays and the trip relays when resetting the system, thus preventing an unwanted trip.

The auxiliary contacts are still used to ensure the trip relay remains sealed-in after the undervoltage relays signal a degraded voltage condition. The failure of the time delay relay is the same as a failure of any other component except the undervoltage relay.

The time delay relay will not fail more than the other components in the existing circuit. If the time delay relay were to fail, an annunciator would alarm on panel 1C08. If both auxiliary contacts on the circuit breakers fail open, then the undervoltage relays will not signal a degraded voltage condition. However, this is not a single element failure. If only one auxiliary contact

fails open, the undervoltage relays will still function as required.

The Degraded Voltage circuitry performs the same function as before. Adequate power is still available to operate the emergency safeguards equipment. The addition of the time delay relay only increases the load on the 125 VDC control voltage by 180 watts, which is insignificant.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1455 ARM Cable Replacement

Description and Basis for Change

This DCP installed a new cable, IR0025-A, from 1C011 to Area Radiation Monitor (ARM), RT-9179. The existing cable had failed and ran through a cable tray in the heater bay marked "DO NOT DISTURB". To prevent further damaging the existing cables in the heater bay, cable IR0025-A was routed to avoid the heater bay. A new conduit was run from cable tray C9A01 to a penetration in the second floor of the Turbine Building to RT-9179. Avoidance of the heater bay should reduce maintenance problems in the future. The existing cable and conduit were removed as much as possible without interfering with or damaging other existing cables.

Summary of Safety Evaluation

This project merely rerouted the cable run to Area Radiation Monitor RT-9179. A new penetration was added; however, it was sealed to meet the fire protection requirements. RT-9179 performs the same function it did prior to the conduit re-routing. Divisional cable separation was maintained, as were fire protection requirements.

The cable does not provide any accident initiating or mitigating signals to equipment important-to-safety. It is electrically isolated from any equipment important-to-safety.

This modification did not involve an unreviewed safety question or a Technical Specification change

DCP 1460 HPCI/RCIC Valve Motor Operator Upgrade

Description and Basis for Change

Information Notice 89-11 identified potential problems resulting from DC MOVs not developing rated torque because of the failure of the original cable sizing calculations to include the proper current values and cable resistances. An earlier NRC Bulletin, 85-03, identified potential problems of MOVs failing to open or close as required due to improper torque switch settings.

Engineering's evaluation of these NRC Documents identified three MOVs requiring design changes to ensure that they were able to develop required thrust during accident conditions. These were MO-2516 and MO-2400 (isolation valves in the RCIC System) and MO-2238 (an isolation valve in the HPCI System).

Motor-operated valves MO-2238, MO-2400, and MO-2516 were modified to increase the available thrust to ensure that adequate thrust is developed by the valves in order to operate as required under degraded voltage conditions. The existing power cables to MO-2516 were replaced with larger cables. This cable replacement increased motor terminal voltage by reducing voltage drop; thereby, increasing motor torque by increasing current to the motor. This design change also replaced the motors on MO-2238 and MO-2400 with larger motors, thereby increasing the available motor torque to close each of these valves. The thermal overloads for MO-2238 and MO-2400 were replaced with overloads sized in accordance with the manufacturer's standards. The cables, circuit breakers, and starters for these motors were not required to be changed.

Summary of Safety Evaluation

The modifications performed by this DCP were designed and installed using design criteria that were the same or more stringent than the design criteria used in the original plant design. Various requirements were considered, including seismic impact, fire protection requirements, environmental qualification requirements, and the effect of cable additions on existing cables routed in the same cable tray (ampacity considerations).

The function and method of operation of these valves were not affected by these modifications. Valve initiating signal and valve opening/closing time were not adversely affected by these modifications. The modifications performed by this DCP did not affect the use of the RCIC or HPCI systems to mitigate the consequences of accidents. The modifications improved the capability of the existing MOVs by increasing the available voltage at the motor terminals of MOV MO-2516 and increasing the torque capability of the motors on MOVs MO-2238 and MO-2400, thus enhancing the existing systems.

The cable modifications and motor replacements performed by this DCP did not affect the operation of any plant system. Because the new cables replaced existing cables and were routed in the same area, and met the requirements for fire protection and environmental qualification, they did not introduce any new failure modes. Because the new motors replaced existing motors and were mounted in the location of the motors being replaced, and met the requirements for environmental qualification and seismic considerations, they did not introduce any new failure modes. The larger conductor size enhanced system performance by reducing voltage drop. The replacement motors enhanced system performance by increasing the torque available to operate the valves.

The limiting conditions for operation for the HPCI and RCIC systems as described in Technical Specifications were unaffected by these changes. These valves have Technical Specification maximum operating times for their containment isolation functions. This modification did not increase valve closure time, thus the basis for containment isolation technical specification is not reduced.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1461 HPCI and RCIC Steam Trap Drain Lines

Description and Basis for Change

The HPCI and RCIC systems have steam-turbine-driven pumps to assure adequate core cooling. Steam supply line drain pots collect condensate which forms in the lines during the time the systems are in a standby/readiness mode. This condensate is piped through steam traps to the main condenser. Several valves are in these lines for isolation, bypass, and testing purposes.

The valves in the steam condensate drain lines had a history of packing and bonnet leaks which discharged steam into the HPCI and RCIC rooms. The steam trap bypass valves had controller problems and seat leakage problems. The isolation valves downstream of the steam traps had seat leakage problems. Erosion had occurred in the downstream piping and caused steam leaks.

This project upgraded the steam drain trap system by improving the piping and valve arrangement and by selecting improved valves. On each system, a single line with two manual isolation valves replaced the existing test line upstream of the steam trap and steam line downstream of the steam trap. The new drain line systems consist of six valves, a steam trap, and a thermal dispersion level sensor. All valves are of a design to minimize packing and seat leakage problems. The isolation valves are upstream of the steam trap. The steam trap consists of a bi-metal bar assembly that pulls a ball into an orifice when steam is present. Water in the trap conducts heat away from the bi-metal, releasing tension on the ball, and discharging the water. A manual bypass valve for each steam trap was provided to facilitate draining the system during the refueling outage for leakage rate testing.

Summary of Safety Evaluation

The modified configuration of the drain lines did not affect the operation of the HPCI or RCIC systems. The drain lines are isolated during operation of their respective systems. The steam traps function in the same way as before the modification when the systems are in the standby/readiness mode.

Replacing the automatic controls on the steam trap bypass valve with manual controls did not degrade the function of the drain

lines. The steam trap will only fail in an open position which will still perform the intended function of removing water from the system.

The electronic level sensor operates on a thermal dispersion design eliminating the need for a ball float level switch. This reduces the possibility of the level switch indicating a "HI" level due to a stuck ball float. The electronic level sensor has a higher degree of overall reliability than the ball float level switch. In the unlikely event that condensate would form in the line, the level indication in the Control Room would alert Operations to open the bypass valve.

Failure of the new drain system design to perform their function of keeping the steam supply lines free of condensation or to isolate upon system initiation has the same consequences as failure of the current design to perform these functions.

The modification improved the reliability of the steam trap systems and availability of the HPCI and RCIC systems.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1462 <u>Essential AC Enhancements</u>

<u>Description and Basis for Change</u>

The Instrument and Uninterruptible AC systems were modified by DCP 1411. The modifications included installation of an inverter/regulating transformer combination to supply power to 1Y11/1Y21 (instrument power distribution panels) and 1Y23 (uninterruptible power distribution panel).

As a result of the installation of the instrument panel inverters, the maintenance cross-tie between the panels was removed. DCP 1462 re-configured the DC source to the inverters to ensure the instrument panels remain operating during MCC maintenance.

DCP 1462 also provided for the removal of the Uninterruptible Power Motor Generator (UPSMG) set which was no longer connected.

Panel 1Y23 was extremely difficult to work in due to the quantity of cable present. This modification provided for cleaning up 1Y23.

<u>Summary of Safety Evaluation</u>

This modification did not affect the existing function of the involved equipment. The addition of the alternate AC feed to battery charger 1D120 did not reduce the function of the charger to maintain the bus and charge the batteries. The common enclosure that provides for selection of feeds for 1D120 is a Class 1E seismically-qualified cabinet. Divisional separation was maintained at all times including internal separation in the enclosure. 1Y22 was seismically qualified to the extent that it

will remain intact during a seismic event. The qualification cannot ensure that an inadvertent transfer will not occur during the event. This is acceptable since the alternate source is as reliable as the normal source. 1Y22 remains to supply 1Y23 as originally evaluated. The reworking of 1Y23 was a housekeeping item only and did not affect the function.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1463 <u>Core Spray Test/Bypass Valves and Chiller Well Water Bypass Valve Logic Modification</u>

<u>Description and Basis for Change</u>

<u>Core Spray Test/Bypass Valves Logic Modification</u>

Motor-operated valves MO-2112 and MO-2132 are utilized in the Core Spray System to provide for full flow system testing. These valves are normally closed in the Core Spray Standby/Readiness lineup and are not required to be opened during initiation of Core Spray. If a Core Spray Initiation Signal is generated while testing is in progress, a "close" signal is sent to MO-2112 and MO-2132 to prevent diversion of the water and ensure the required flow is delivered to the reactor.

During manual closure of MO-2112 and MO-2132, the closure signal was removed when a predetermined torque setting was reached and a torque switch opened. During automatic closure, the closure signal was removed when the valve reached the closed position, as determined by a limit switch. This deenergized the closing coils and the valve motor would coast down. This should have been sufficient to ensure valve closure but, unfortunately, the motor coast down period was insufficient to ensure complete valve seating. This could have resulted in the Core Spray System becoming depressurized. To prevent this from happening, the Operator was required to give the valves a manual close signal until the torque switch was actuated and its associated contacts opened. This situation was unacceptable because automatic valve closure should not require any type of Operator action.

This design change utilized auxiliary contacts on the motor starters of Core Spray valves MO-2112 and MO-2132 to seal in the automatic closure signal until it is removed by the torque switch. This caused automatic closure to be terminated in the same manner as manual closure thus ensuring that the valves would seat upon receipt of an automatic closure signal. Furthermore, the modifications were accomplished in such a manner as to preclude hammering of the valves into their seats as a result of a repeated closure signal.

Chiller Well Water Bypass Valve Logic Modification

The Chiller Well Water Bypass Valve MO-2039C is interlocked with well water isolation valves MO-2039A and MO-2039B to prevent MO-2039C from opening when either (or both) MO-2039A and MO-2039B are open. Motor-operated valve MO-2039C could experience a hammering effect if either MO-2039A or MO-2039B were open and the torque switch for MO-2039C were to relax. For this reason the valve closing logic associated with MO-2039C was revised so as to prevent the hammering effect.

This modification utilized the limit switch and auxiliary motor contacts in the valve closing logic of MO-2039C to seal in the closure signal so that valve closure continues to be terminated by a torque switch. The limit switch is placed in series with the torque switch. The limit switch is set to open when the valve is approximately 95% closed, and is bypassed by the auxiliary contacts. This configuration prevents any hammering effect should the torque switch relax after the valve is closed with an automatic closure signal present.

Summary of Safety Evaluation

Core Spray Test/Bypass Valves Logic Modification

The operating characteristics of the Core Spray Test/Bypass Valves were not degraded. The change increased the probability of valves MO-2112 and MO-2132 closing upon a Core Spray Initiation Signal, thus ensuring the ability of the Core Spray System to supply the required flow and discharge pressure to the vessel if needed.

The only effect on the Core Spray System was to cause the automatic closure signal sent to the Test/Bypass Valves to be removed by a torque switch instead of a limit switch. Automatic closure and manual closure are now terminated in the same manner. Upon receipt of an automatic closure signal, the Core Spray Test/Bypass Valves begin to close. These valves continue to move in the close direction until the valves are closed and the proper torque has been applied. Having the valve closure signal terminated by the torque switch rather than the limit switch ensures that the valves are seated. This prevents the Core Spray System from becoming depressurized and eliminates the potential for valve damage due to excessive water hammer should the Core Spray System be initiated in the event of an accident.

The torque switch is no more likely to fail than the limit switch. Should the torque switch fail to open when the valves are closing, the valve motor starters would trip on overload. The overloads should trip in sufficient time to preclude damage to the valve motors. However, since MO-2112 and MO-2132 are required to be closed and need not be opened during Core Spray Initiation, even if damage to the valve motors were to occur, the safety function of the Core Spray System would not be compromised. Failure of the

torque switch to reset when these valves are opened for testing would cause the closing coil to deenergize once the valve reaches the intermediate position, should the Core Spray System be initiated. This would require the valve to be closed locally. However, this situation is not new. This was the case even prior to this design change.

The Core Spray System is designed to mitigate the consequences of an accident. Overall system performance was not adversely affected.

The net result of this modification was to increase the probability of complete closure of MO-2112 and MO-2132, thereby increasing the probability that the Core Spray System will perform its design function. The change did not create the possibility of any new accidents or malfunctions. This design change decreased the possibility of valve damage due to hammering.

Chiller Well Water Bypass Valve Logic Modification

The Chiller Well Water Bypass Valve MO-2039C is not a safety-related valve. It is a part of the Well Water System and is not required to operate to mitigate the consequences of an accident or a malfunction of equipment important to safety. The potential for valve MO-2039C to experience the hammering effect was eliminated by this modification.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1464 RWCU Pipe Replacement

Description and Basis for Change

Generic Letter 88-01 required that licensees inspect all susceptible stainless steel piping four inches in diameter or larger and containing reactor coolant over 200°F. This requirement dictated that we include the applicable non-safety-related RWCU piping outside the ISI boundaries in our inspection program.

Inspecting the welds as-is would have required the weld crowns to be ground down before they could be ultrasonically tested. This would have been costly in time and radiation dose. Engineering investigation revealed that replacement of the affected pipe with IGSCC resistant materials to be more cost effective due to decreased inspection requirements in the future. The piping layout remained the same with the exception that three valves were removed. Valves V-27-126, V-27-127 and V-27-128 were removed so there is no longer the possibility to switch from hot to cold lineup to the pumps.

Summary of Safety Evaluation

This modification installed IGSCC-resistant piping in areas where there was a possibility of IGSCC occurring. The intent of the modification did not affect the function of the RWCU system. The RWCU piping and equipment altered in this DCP were constructed in accordance with the design, material, and construction standards associated with the RWCU system. This design change did not adversely affect the overall system performance and reliability of the RWCU system. The RWCU operating conditions were not altered as a result of this design change.

The consequences of a pipe break outside of the primary containment valves was not increased as a result of this modification. The piping material will be less susceptible to IGSCC-induced cracking. This modification did not alter the design of any equipment important-to-safety.

Removal of the three valves did not change the functional design characteristics of the RWCU system. These valves were installed in 1983 to insure adequate net positive suction head for the RWCU pumps over the entire operating range of the system. However, operating experience has shown that these valves remained in their normal positions (two closed and one open) throughout the full range of operations. Net positive suction head requirements were met without rearranging the flowpath. Therefore, they were no longer necessary and were removed.

The Primary Containment Isolation System (PCIS) Group 5 high differential flow, high ambient temperature, and high differential temperature setpoints were not altered as a result of this modification. Therefore, the margin of safety for the PCIS Group 5 isolation was not reduced. Flow orifice FE-2747 was replaced as a part of this piping replacement. The new orifice housing and plate have been evaluated as not altering the flow output signal from the flow orifice.

The heat transfer area of the piping and valves will be slightly reduced as a part of this modification and the heat addition into the RWCU Heat Exchanger Room will not be significantly altered. Therefore, the existing setpoints of the instruments for the PCIS Group 5 high ambient temperature and high differential temperature switches are acceptable.

This modification did not involve an unreviewed safety question or a Technical Specification change.

DCP 1467 MSIV Valve Solenoid Failure Detection

Description and Basis for Change

On March 5, 1989, with the reactor operating at 100% power, calibration of the main steam line radiation monitors was in progress when the B outboard main steam line isolation valve (MSIV)

unexpectedly closed due to a failed DC solenoid. The isolation of main steam line B resulted in flow in the remaining three main steam lines exceeding the high flow limit of 140%. In accordance with design this resulted in an isolation of all main steam lines. When MSIVs reached the less than 90% open position, an automatic reactor scram occurred.

The cause of the unexpected closure of main steam line B isolation valve was a failure of SV-4416B, a DC solenoid coil. Solenoid SV-4416B worked in combination with an AC coil SV-4416A, to control a three-way valve that supplies nitrogen to the MSIV actuator to hold it open. Both solenoids must be deenergized for the MSIV to close. In this event, the DC coil was failed open, and when testing deenergized the AC coil, the MSIV closed. Failure of the DC coil was not readily detectable because no direct indication of solenoid status existed.

This design change installed indicators in the existing power circuit. This modification provided direct monitoring of MSIV solenoid status, thereby reducing inadvertent scrams caused by indeterminate solenoid status.

Summary of Safety Evaluation

The circuit modifications performed by this DCP improved the means for direct monitoring of the energization status of MSIV solenoids. This should reduce the number of inadvertent MSIV closures during associated logic surveillance testing and therefore, reduce the number of challenges to the MSIV system.

The circuit modifications were internal to Control Room panels 1C41 and 1C42. The cables were in the same area and they did not introduce any new failure modes. The components added are for monitoring only, and are passive in operation. The failure modes of the components are an open or short circuit. Either failure mode of the components will allow the MSIV to operate properly. Both monitoring circuits on each MSIV would have to fail to result in a closure of the MSIV. A single component failure will not result in an unexpected closure of the MSIV.

The function and method of operation of these valves were not affected by these modifications. Valve opening/closing time was not adversely affected by these modifications.

This DCP did not affect valve operation, initiating signal or closure time; thus, the margin of safety defined in the basis of Technical Specifications was not reduced. The modifications performed by this DCP did not adversely affect the operation of any plant system, but rather enhanced system performance by reducing potential for accidental closure of an MSIV during surveillance testing.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1470 Phase II LPCI Swing Bus Modifications

Description and Basis for Change

The Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal (RHR) System requires that the output of all available RHR pumps be directed to a single injection point. The BWR 3/4 design accomplishes this by powering the Division I and Division II LPCI inject valves from a common power source or "swing bus." At the DAEC, the swing bus is comprised of Motor Control Centers (MCC) 1B34A and 1B44A. These MCCs are solidly tied together via cable. The swing bus is equipped with a power seeking logic which will transfer the bus to the alternate power supply in the event of a failure of the normal power supply.

Both swing bus feeders are equipped with an electrically-operated, air circuit breaker (ACB) and a molded case type isolation/maintenance breaker (MCB). The swing bus can be fed from either division, but is normally fed from Division I power.

The LPCI swing bus power supply design senses power at the bus of load centers 1B3 and 1B4. In letter NG-88-3787 to the NRC, we committed to investigate methods to directly monitor LPCI swing bus voltage. It is desirable to monitor as close to the swing bus as possible because any open circuit between the point being monitored and the swing bus could cause an undetected loss of swing bus voltage.

The upstream or line side of the isolation/maintenance breakers was chosen as the best monitoring location for the following reasons: 1) it is close to the swing bus, 2) an overcurrent fault on the swing bus will cause a trip of 1B3402, but the system will "think" voltage is still available thereby preventing a transfer of the faulted bus to the other emergency diesel generator, 3) the sensing point is upstream of the transfer breaker; therefore, a check can be made to determine if voltage is available from the other supply before transferring to that supply.

The modification relocated the existing AC undervoltage relays previously located at 480 V load centers 1B3 and 1B4, to MCC 1B34A and 1B44A. The relays monitor the availability of incoming power on the line side of the isolation/maintenance breakers. This modification allows the swing bus transfer logic to monitor incoming swing bus supplying voltage as close as possible to the swing bus without sacrificing the capabilities of the existing transfer logics. In addition, a voltmeter was added to provide local indication of voltage availability.

In the event of a loss of incoming power to the Division I normally-closed swing bus feeder breaker, the undervoltage relay would initiate swing bus transfer provided 1) the normally-closed swing bus feeder breaker did not trip due to a swing bus fault and 2) the alternate swing bus power supply was available. This

criteria is unchanged from the existing logic. The breaker control logic was not changed or modified.

Summary of Safety Evaluation

The probability of accidents that are analyzed in the DAEC UFSAR is based on the initial conditions and assumptions for each event. The LPCI system and supporting subsystems (including the swing bus) does not affect any of these initial conditions or assumptions. No failure or malfunction of the LPCI swing bus can initiate any of the accidents previously analyzed. The modifications performed by DCP 1470 do not affect the operation of any other plant system.

The relocation of the undervoltage relays changed the location where LPCI swing bus supply voltage is monitored. Because the LPCI swing bus continues to perform the same safety function, operate in the same manner and have the same time response to a loss of power, the function and operation of the LPCI swing bus system is unchanged.

In accordance with the UFSAR, the LPCI swing bus may be required to perform safety functions for the following identified accidents:

a. LOCA (pipe break) inside and outside of primary containment
b. Control rod drop accident

The function and operation of the LPCI swing bus was not adversely affected by these modifications. In fact, the transfer capability of the swing bus was improved by removing potential failure mechanisms.

The modifications performed by DCP 1470 improved the reliability of the swing bus operation. Relocating the undervoltage relays did not change the probability of relay failure. Moving the undervoltage relays from load centers 1B3 and 1B4 to MCCs 1B34A and 1B44A allows monitoring of the supply voltage as close to the swing bus as possible which improves load transfer capability. No other equipment important to safety was affected by this modification.

The relocation of the undervoltage relays was performed using criteria that were the same as or more stringent than the original installation criteria and considered the following requirements:

1. Seismic impact of the MCC 1B34A/1B44A and load center 1B3/1B4 modifications

2. Fire protection impact due to increased combustible loadings

3. Effect of LPCI swing bus system operation on other systems

4. Effect of cable additions on the existing raceway system and the effect of the cable addition on existing cables routed in the tray

The surveillance requirements and limiting conditions for operation of the LPCI subsystem as described in the basis for Technical Specification 3.5 were unaffected by these changes. The modifications performed by this DCP did not adversely affect the operation of any plant system, but enhanced the LPCI system by eliminating potential failure mechanisms on the swing bus.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1473 <u>MSIV-LCS Steam Tunnel Cable Replacement</u>

<u>Description and Basis for Change</u>

The cables routed to the Leakage Control System within the Steam Tunnel were suspected of being cracked and embrittled. Maintenance on the MSIV-LCS valves was scheduled for the 1990 Refuel Outage, and it was expected that the embrittled cable insulation would be damaged and the cables would need replacement. A section of cables going to the MSIV-LCS and RCIC motor-operated valves and the MSIV-LCS heaters were replaced. Terminal boxes were installed above the CRD Repair Room and the MG Set Room to facilitate any needed future replacement of cables under the maintenance program.

<u>Summary of Safety Evaluation</u>

The materials and installation met the qualifications for use in these areas of the power block (Divisional separation, seismic mounting of equipment, and use of EQ qualified terminal strips). The terminations made within the junction boxes were on EQ qualified terminal blocks. This project did not change any of the circuits. The junction boxes installed above the CRD Repair Room and in the MG Set Room were seismically mounted and did not affect the operation of any other piece of equipment.

This modification did not change the function or operation of the MSIV-LCS motor-operated valves, heaters, or the RCIC motor-operated valves. All of the applicable equipment used in this modification was EQ qualified and did not reduce the margin of safety.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1475 SRM/IRM Drive-in Light Logic, Auto-Dispatch Disconnect and Auto-Depressurization Control Room Modifications

SRM/IRM Drive-in Light Logic Modification

Description and Basis for Change

This DCP addressed concerns identified in various Engineering Work Requests.

- The back-lighting lamp for the SRM/IRM Drive-in switch was modified to keep the light energized when the switch is engaged.

- Separate controls were provided on 1C-07 for Steam Packing Exhauster throttle valves MO-1178 and MO-1180. In addition, a new instrument loop was added to provide Steam Packing Exhauster pressure on 1C-07.

- The Feedwater Control Lockout Relay indicator lights were changed to "DIM-BRIGHT" lamps which are bright when the lockout initiation signal is present and the lockout relay is tripped, but dim when the initiation signal is reset.

- The Demineralizer System Bypass handswitch was relocated on panel 1C-06 to be aligned with the low pressure feedwater heater bypass controls and to reduce the possibility of inadvertent actuation of the control for Condensate Pump 1P-8B.

- Reactor vessel water level inputs from LI-4539 and LI-4540 were added to the Plant Process Computer.

- The scales for Condenser Back Pressure indicators were annotated to indicate the Group 1 isolation and Turbine Bypass Valve Closure setpoints.

- Miscellaneous Control room labels were changed to more correctly reflect the functional description of the associated components.

Summary of Safety Evaluation

The SRM/IRM Drive-in switch indicating light does not interact with any equipment important to safety. It provides an indicating function only, giving the operator local feedback of the position of the associated switch. Other lights are available in the same light matrix to indicate when the selected detector is in the FULL-IN or FULL-OUT position.

The previous design of the Steam Packing Exhauster System coupled blower status and blower outlet valve position. The valves were fully open when the associated blower was operating and closed when the blower was not operating. The outlet valves could not be throttled in response to changing system conditions. This DCP provided separate controls for outlet valves MO-1178 and MO-1180

to allow these valves to be throttled. Providing throttle control of the discharge valves and pressure indication allows the operator to maintain better control of the Steam Packing Exhauster system. This enhanced control will result in better operator response to condenser backpressure anomalies.

Modification of the Feedwater Control Lockout Relay indicating lights provides the operator with indication that the lockout relay may be reset without possible damage to the relay coil. This modification did not affect the function of the Feedwater Control System. No new failure mode for the Feedwater Control System was created.

Relocating the Demineralizer System Bypass handswitch did not affect the function or operation of the Demineralizer System and did not affect any other equipment considered important to safety.

The signals displayed on LI-4539 and LI-4540 were placed into the Plant Process Computer (PPC) via the Safety Parameter Display System divisional data acquisition subsystems. These subsystems contain optical isolation devices which isolate the PPC from its inputs. Failure of the PPC will not propagate into its input circuitry. The loop for LI-4539 provides indication only. The loop for LI-4540 provides indication as well as the reactor vessel level inputs to HPCI and RCIC when control is transferred to 1C-388, the remote shutdown panel. However, when control is transferred to 1C-388, the Plant Process Computer input is "disconnected" by the transfer switch. The loop's control function will not be active at the same time as the PPC input.

Providing setpoint information on PI-1476 and PI-1477 did not affect the operation of the Condenser Backpressure trips. This indication is not relied upon to mitigate the consequences of any accident analyzed in Chapter 15 of the UFSAR.

Changing Control Room labels to more accurately reflect the functional description of the associated equipment will enhance the operator's ability to operate that equipment.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

Auto-Dispatch Disconnect and Auto-Depressurization Control Room Modifications

Description and Basis for Change

- Automatic Depressurization Timers

  Automatic Depressurization System (ADS) timers were supplied without the expected indicator lights. This made it difficult for operators to perform required Emergency Operating Procedure (EOP) actions based upon when the timers initiated. For this

reason, amber indicator lights were installed directly above the ADS timers in Panel 1C-03.

- RHRSW LOCA Override Switches

  The RHRSW LOCA override switches were not located near their associated RHRSW pump controls. This DCP relocated the RHRSW LOCA override switches to a more obvious position above the RHRSW pump controls.

- Auto-Dispatch Disconnect

  During the October 23, 1989 start-up, attempts to synchronize the Generator to the grid were prevented due to the inadvertent energization of the Auto Dispatch System. The Auto-Dispatch System was originally installed at the DAEC to allow the central load dispatcher to make small changes in Generator output to match system load. As its use was never licensed at the DAEC, the system was "abandoned in-place". This DCP disconnected the Automatic Dispatch System from its 24V power supply to prevent inadvertent energization of the circuit in the future.

Summary of Safety Evaluation

- Automatic Depressurization Timers

  Revised EOPs require operators to perform actions based on when the Automatic Depressurization System timers initiate. These timers were expected to have indicating lights on the face of the timer, but due to internal wiring of the timers, the manufacturer was unable to include face lights. An annunciator is activated upon timer initiation, but it is difficult to locate quickly. The installation of amber indicator lights above the timers performs the same function as the expected face lights and does not affect the operation of the timers. The lights will allow operators to perform in a timely manner if events require initiation of the Automatic Depressurization System.

- RHRSW LOCA Override Switches

  The RHRSW LOCA override switches were relocated to a position above their respective RHRSW pump controls. This was done to make them easier to locate in an emergency situation requiring their use. This relocation did not affect the operation of the switches or the operation of the associated RHRSW pump controls.

- Auto-Dispatch Disconnect

  The Automatic Dispatch System had been disabled by the installation of a jumper. Inadvertent energization of the Automatic Dispatch System could hinder attempts to synchronize

the Generator to the grid. Disconnecting the system from its 24V supply prevents inadvertent energization of the circuit.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1476 Main Steam Isolation Valve Upgrade Project

Description and Basis for Change

The Main Steam Isolation Valves (MSIVs) required modification to improve their capability to pass Local Leak Rate Tests (LLRTs) in accordance with the requirements of the Technical Specifications; to correct known problems encountered at other plants; and, to simplify and shorten maintenance activities in order to reduce personnel radiation exposure.

The function of the MSIVs is to close and isolate the four main steam lines when primary containment isolation is required to limit the release of radioactive materials or to limit the loss of reactor coolant following postulated accidents. In order to be able to perform their intended function, the MSIV are designed to close within time limits established by the design basis accident analyses, and to limit the leakage rate as specified in the Technical Specifications. The MSIV's ability to perform their safety-related function is demonstrated by passing a stringent pneumatic leak test at each refueling outage.

The first of several tasks under DCP 1476 was to modify the MSIVs to enhance their capability to perform their safety-related function without reducing their reliability or availability. This task involved replacement of the two piece Main Disk/Piston assembly with a one piece assembly, installation of additional disk guide pads, installation of larger actuators, installation of stiffer topworks and stronger springs, installation of new bonnets and installation of improved stems and couplings.

The second task under OCP 1476 involved modifying the MSIV nitrogen supply piping to avoid interferences with removal and installation paths required to perform the above.

The third and fourth tasks under DCP 1476 involved modifying 1" main steam instrument lines and drain lines which were previously connected to feedwater valves V14-0002 and V14-0004, respectively. These modifications were also being performed to avoid interferences with Task 1 work.

The fifth task was installation of new rigging lugs on overhead steel in the drywell to assist in moving of the old and new MSIV actuator and topworks.

Summary of Safety Evaluation

The modifications were intended to improve the function of the MSIVs. For example, the one piece main disk and piston design reduces the probability of inadvertent MSIV closure which could be caused by component separation that is possible with the previous threaded design. Therefore, the modifications did not increase the probability of a nuclear system pressure increase already evaluated in Section 15.2 of the UFSAR. The effect of the increased MSIV topworks and operator weight on the main steam line valve body and valve bonnet stress analyses was evaluated to demonstrate that the resultant stresses were within the allowable limits. Therefore, the probability of the main steam line break accident postulated in UFSAR Section 15.6.5 is not increased.

The modifications did not affect the MSIV's principals of operation, did not add any new functional requirements and did improve their capability to close and their leak tightness. The design characteristics of the MSIV control and instrumentation were unchanged by the modification such that the MSIVs will respond to events, such as main steam line pressure decrease, high steam flow and high radiation in the main steam lines in the same manner as previously evaluated in the UFSAR.

The actuator, topworks and valve disc and body modifications were performed to increase valve reliability, improve performance and reduce the possibility of stem galling and disc misalignment. Therefore, no malfunction should be postulated to occur.

The other minor tasks were performed to facilitate the MSIV modifications by re-routing piping to eliminate physical interferences and installing new rigging lugs.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1479 Scram Frequency Reduction Committee Recommended Modifications

Description and Basis for Change

The turbine trip bus was designed to trip on input from any single trip sensor. This meant that the turbine was subject to trip for any single component failure in the trip bus. This DCP was performed in order to reduce the plant vulnerability to a scram due to a component failure in the turbine trip bus. Performed under the auspices of the Scram Frequency Reduction Committee, this modification changed the following trips to two-out-of-three logic.

- Low Main Shaft Oil Pump Discharge Pressure

  This turbine trip occurs when the discharge pressure from the turbine main shaft drops below 105 psig and if the turbine is operating above 1300 rpm. By increasing the number of pressure

switches from one to three and interconnecting the switches in a two-out-of-three logic arrangement, the susceptibility to a single pressure switch failure was eliminated. When two of the three pressure switches contacts close, operation of the trip will proceed as originally designed with the single pressure switch.

- Low EHC Hydraulic Fluid Pressure

  This turbine trip occurs when the EHC oil pressure drops below 1100 psig. By increasing the number of pressure switches from one to three and interconnecting the switches in a two-out-of-three logic arrangement, the susceptibility to a single pressure switch failure was eliminated. When two of the three pressure switches contacts close, operation of the trip will proceed as originally designed with the single pressure switch.

- Loss of Stator Cooling

  The stator cooling trip monitors the temperature and pressure of the stator cooling water return line. When the design limits of either of these two parameters are not met, a turbine runback is initiated. This occurs when flow is less than 239 gpm or the water temperature is greater than 86 degrees C. Runback of the turbine is designed to protect the main generator from damage due to overheating. If the generator load is not reduced to 79.5% within 2 minutes or 25% within 3.5 minutes, the turbine is tripped. By increasing the number of temperature and pressure switches from one to three and interconnecting the switches in a two-out-of-three arrangement, the susceptibility to a single component failure, was eliminated. When two of the three switches contacts close, operation of the trip will proceed as originally designed with the single switch design.

This modification also installed a current meter in 1C-49 to provide an indication of master trip solenoid status to aid during weekly testing. The meter indicates the solenoid current. In the event that the solenoid and the logic to the indicator were to fail, the current meter can be used to determine solenoid status before testing it. This indication can be used to prevent an inadvertent turbine trip during testing.

Summary of Safety Evaluations

The existing turbine trip system design allowed a single sensor to initiate a trip. The new design requires two-out-of-three components to activate to initiate a turbine trip. By adding redundant pressure and temperature switches, the probability of sensing a valid turbine trip was increased and the probability of generating a spurious turbine trip due to a single component failure was eliminated. Addition of the new temperature and

pressure switches did not change the set points of the turbine trip signals.

These changes decreased the probability of occurrence of an accident or equipment malfunction by increasing the reliability of the logic that initiates turbine trips. The consequences of the new logic failing to provide a trip signal when needed are the same as for the existing single sensor design.

The current meters that were added provide an indication of the state of the master trip solenoids. The master trip solenoid retained its operational, trip and test functions. Addition of the current meters allows personnel to verify solenoid position before proceeding with a test. Failure modes for the current meter are a short or open circuit. In the case of a short circuit, the operation of the solenoid will remain the same. In the event of an open circuit, the solenoid will deenergize, but the indicator on panel 1C-07 will go out and indicate that the solenoid is deenergized. If both current meters were to open circuit, a turbine trip would be initiated since power would be removed from the solenoids. The resulting transient has been analyzed in the FSAR. This modification decreased the probability of a master trip solenoid malfunction causing a spurious scram. It does not prevent the master trip solenoid from actuating when a turbine trip is needed.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1483 PS-2024B Replacement

Description and Basis for Change

Pressure switch PS2024B is the RHR pump discharge pressure switch which provides a permissive signal for ADS. While a routine STP was being performed, the switch would not trip at the correct pressure. The STP was run again and it did trip at the correct pressure. This switch was a Static-O-Ring (SOR) pressure switch which did not have a direct replacement. However, SOR had a newer model which would replace the existing switch. This DCP replaced the existing pressure switch with the newer model.

Summary of Safety Evaluation

The replacement switch had basically the same mechanical and electrical characteristics as the existing pressure switch and had no new failure modes. Operation of the RHR or ADS will not be affected. The ADS and RHR systems will continue to perform as designed. The pressure switch and circuit will continue to perform the same function, but will be less susceptible to failure.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1486 Steam Leak Detection System Enhancements

Description and Basis for Change

The Steam Leak Detection (SLD) system provides isolations of the High Pressure Coolant Injection (HPCI) and the Reactor Core Isolation Cooling (RCIC) systems based on temperature, pressure, and flow sensors with associated instrumentation. The leak detection system for the Reactor Water Cleanup (RWCU) system utilizes temperature, flow, and level sensors.

The isolation logics are such that the HPCI and RCIC systems will immediately isolate upon detection of low steam supply pressure or high steam flow, which are indicative of a major steam line rupture. The RWCU system immediately isolates upon detection of low reactor vessel level which also is indicative of a major line rupture. These three systems also have local temperature detectors which combine to provide system isolations on either high equipment area temperatures or high area differential temperatures in the event of a small line break. It is this portion of the steam leak detection system that this design change affected.

This design change replaced and/or repaired the shielding around the thermocouple extension wires as well as tested this shielding to ensure that it is properly grounded, thereby reducing or eliminating the potential for noise signals to be imposed on these circuits. Temperature elements that were determined to be improperly positioned were relocated to improve overall system performance and reliability.

Contacts on the currently-installed test switches, which are connected between the thermocouple elements and the temperature switches and are used to disconnect these sensors from their associated temperature switches, were removed from this portion of the steam leak detection circuitry. These contacts were replaced by sliding link disconnects. This eliminates the potential for thermocouple junctions to be formed due to dissimilar metals being placed in contact with each other.

This DCP replaced Riley temperature switches which did not have burnout protection with an upgraded version of this temperature switch which has a burnout protection feature.

This design change also replaced the timers associated with the RWCU high differential flow isolation signal with timers that have a more suitable range for this application. Keylock test switches were installed on the Control Room panels that contain these relays and will be used to bypass these relays during surveillance testing. In addition, the time delay associated with this isolation signal was increased to 45 seconds.

Summary of Safety Evaluation

Repairing and/or replacing the shielding around the thermocouple extension wires and relocating any sensors which are found to be improperly positioned improved the overall system performance. The use of sliding link disconnects to open the circuit between the temperature sensors and the temperature switches allows the temperature switches to be tested and calibrated and also provides a good conducting path for this circuit. The high resistance problems associated with the contacts on the currently-installed test switches are eliminated, thereby improving system reliability. These sliding link disconnects will have a higher degree of reliability than the presently-installed test switches. The sliding link disconnects could only malfunction if they were to inadvertently open when they were required to be closed. The construction of these disconnects makes this possibility extremely unlikely to occur. In addition, even if any or all of the sliding link disconnects were to open, the burnout protection feature of the temperature switches would respond by sounding an alarm and initiating an isolation of the affected system or systems.

The burnout feature provides immediate indication of a failed temperature element. This feature improves the ability to detect failures in the SLD system over the previous design which depended on periodic surveillances and instrument checks for failure detection. Automatic detection of a burned out thermocouple will initiate an isolation or an alarm signal to its respective system. The burnout protection feature will not affect the ability of the Steam Leak Detection System to provide isolation or alarm signals to the RWCU system in the event of a small leak.

Increasing the time delay for isolation for high differential flow in the RWCU system to 45 seconds from the current 15 second setting did not increase the probability of a leak developing in the system. System reliability will be improved by this design change as spurious isolations during filling of the system should be eliminated. Should the replacement timers fail, the consequences will be the same as if the currently-installed timers had failed. Increasing the time delay for the high differential flow isolation signal did not increase the magnitude of the consequences of a leak in the RWCU system. The effect of the increased time delay is restricted to the leak detection isolation function of the RWCU system and does not affect any other safety-related systems.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1487 Flex Hose Upgrade/Evaluation

Description and Basis for Change

Flexonics, Inc. corrugated metal flexible hoses were installed on the EHC Oil System. These hoses replaced hard piping that was

prone to leakage at threaded fittings. Due to a failure of the Flexonics hose on the EHC supply to a main turbine control valve, the Flexonics hoses on all EHC high pressure lines, and two low pressure lines were replaced. DCP/EDCP 1444 replaced the Flexonic hoses with Aeroquip Corporation hydraulic hoses. This DCP provided for the replacement of the remaining EHC low pressure hoses to preclude additional flex hoses failures.

The 16 remaining Flexonics hoses on the EHC drain lines from the Control Valves, Main Stop Valves, Bypass Valves, and Combined Intermediate Valves were replaced with Aeroquip hydraulic hoses. The flex hoses for the instrument air supply to Feedwater Regulating Valves CV-1579 and CV-1621 were also replaced with Aeroquip hoses.

Summary of Safety Evaluation

EHC System

The EHC System provides hydraulic fluid to operate the main turbine valves and also provides rapid closure of these valves under certain emergency conditions. Installation of the Aeroquip hydraulic hoses decreased the probability of occurrence of a hose failure because Aeroquip hoses are less susceptible to torsional loads than are corrugated metal hoses.

The worst-case failure of the flexible hoses would be a leak or rupture, resulting in a loss of the EHC fluid. Rupture of the EHC drain hoses is unlikely, however, because the hoses were installed on the low pressure side of the EHC System. Rupture of an EHC drain hose would not result in an immediate loss of turbine valve control, but rather would result in a gradual lowering of the fluid level. Control of the valves would be maintained until reservoir levels were significantly reduced. Fluid could be added to the reservoir during operation to retain valve control.

Assuming the ruptured hose results in a total loss of EHC fluid, the loss of fluid and decrease in EHC oil pressure would eventually result in an automatic closure of the main turbine stop valves, control valves, and combined intermediate valves. These valves are designed to close on a loss of system pressure (bypass valves fail as-is). Chapter 15 of the UFSAR analyzes the consequences of turbine control valve fast closure (without bypass) and turbine stop valve closure (without bypass). Failure of the EHC hoses does not increase the probability of occurrence of these accidents, nor does it result in a more severe transient than previously analyzed.

The technical specification margins for fuel cladding integrity will not be reduced due to a worst-case failure of the turbine EHC oil system. The Technical Specification requirements for Reactor Protection System actuation for turbine control valve fast closure and stop valve closure are not affected by the addition of EHC

hydraulic hoses. Also, there is no impact on the Recirculation Pump Trip actuation as defined in Technical Specifications.

Instrument Air System

The Aeroquip hoses are less susceptible than the corrugated metal flex hoses to problems caused by 3-dimensional movements. The use of Aeroquip hydraulic hoses therefore reduces the probability of occurrence of a hose failure.

The worst case failure of these hoses would be a loss of instrument air to the operators of the feedwater regulating valves. Loss of instrument air would cause the feedwater regulating valve actuators to fail "as is". Failure of the feedwater regulating valves is addressed by existing plant procedures. Reactor water level may be controlled by valves MO-1592/1636 and by adjusting reactor recirculation flow as necessary. Loss of instrument air to the valves will not increase the probability of occurrence of an accident previously analyzed, nor would it result in a more severe transient than previously analyzed in the UFSAR.

Because reactor water level may be controlled by means other than the feedwater regulating valves, the margin of safety as defined in the Technical Specifications bases will not be reduced due to replacement of the corrugated metal instrument air hoses with Aeroquip hydraulic hoses.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1490 Control Rod Replacement

Description and Basis for Change

General Electric upgraded their control blade design. The improved design, the Duralife D-230, provides several enhancements over the original design. Hafnium was added to certain areas to increase blade lifetime. The overall blade thickness was increased which increased the total amount of absorber material used. The velocity limiter was redesigned to lower the rod drop velocities while maintaining the same resistance in the scram direction. Other changes include improved manufacturing techniques and improved boron carbide absorber tube material to eliminate cracking.

Four of these Duralife D-230 control blades were installed in the reactor vessel during the 1990 refuel outage. This DCP approved the use of the Duralife D-230 as a direct replacement for the original-design control rod.

Summary of Safety Evaluation

Control rods function to control the overall reactivity of the reactor core and as such, the only transients which can be initiated by control rods would be reactivity addition/removal

events. These types of events are analyzed in Section 15.4 of the UFSAR. The Control Rod Drop Design Bases Accident analysis is the most limiting event for reactivity-related events. The Control Rod Drop Accident (CRDA) analysis assumes that a fully inserted control rod becomes disconnected from its drive mechanism and sticks in the full-in position while the control rod drive mechanism is fully withdrawn. Sometime later, the rod falls from the fully inserted position to the fully withdrawn position. The rod drop results in a significant amount of reactivity being added to a small, localized area of the core. The initial prompt power excursion is turned by the Doppler coefficient and the event is terminated when the reactor scrams on APRM high flux.

In order to ensure that the original CRDA analysis was still bounding, the improved design Duralife D-230 was evaluated against the original all boron carbide rod. Since the velocity limiter had been redesigned, extensive tests were conducted on the D-230 to verify that the rod drop velocity would be less than or equal to that of the original design. Tests confirmed that rod drop velocities and scram performance were within the original design limits. Since the D-230 is thicker than the original control rod, a study was performed which showed that the D-230 will operate with no increase in probability of fuel channel interference.

The D-230 features a hafnium plate in the top 6 inches of the blade as well as a hafnium strip down the length of each wing. The blade is thicker overall, so there is more hafnium as well as boron carbide absorber material present. Overall, this increase in absorber material results in a slight increase in the reactivity worth of the blade. Calculations showed that the slight increase in rod worth was within the statistical uncertainties of the calculations. Therefore, it was concluded that the D-230 is interchangeable with the original design and that the reactivity addition caused by the D-230 blade during the postulated CRDA will not result in exceeding any design bases.

Scram times, rod drop velocities and reactivity worths were all within the design limits of the original all boron carbide rods. The use of the D-230 control rod in the core of the DAEC is completely acceptable and is bounded by the original CRDA analysis.

The reduced boron carbide absorber tube wall thickness was evaluated to ensure that the effect of boron carbide swelling and helium gas build-up would not exceed the material stress limits. Results showed that the helium gas build-up at the end of the rod lifetime will produce tube wall stress levels of approximately 77% of the ASME code allowable stresses. The effect of boron carbide swelling was also analyzed and it was shown that the absorber tube cladding will not experience a significant difference in the strain levels from that of the original design and that the high purity stainless steel will meet the cladding strain requirements at the end of the nuclear life of the rod.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1495 Addition of Revision 4 EOP Graphs to the DAEC SPDS

Description and Basis for Change

The Safety Parameter Display System (SPDS) provides a concise display of critical plant information to the control room operators to aid them in rapidly and reliably determining the safety status of the plant. This information consists of the status of selected safety parameters and the associated plant variables. These variables are derived from existing plant instrumentation systems.

In their Inspection Report (IR-86-20), the NRC recommended improvements to emergency preparedness. As a result, eleven Emergency Operating Procedure (EOP) graphs were implemented on the existing DAEC Safety Parameter Display System (SPDS). The graphs were implemented in the form of touch-screen displays. Software was integrated with the existing SPDS software including the addition of touch points to access the EOP displays. Existing SPDS displays were revised to show the status of the EOP pages.

This project involved modifying the software on the Plant Process Computer (PPC) only; there were no hardware modifications necessary to implement the software changes.

Summary of Safety Evaluation

The purpose of the changes to the SPDS was to aid the operator in the assessment of plant conditions during an emergency. This will help the operator to reduce the consequences of a malfunction of equipment important-to-safety.

The new displays will be used in addition to the Emergency Operating Procedures. No actions will be taken by the operators in response to these displays alone. This design change did not alter the interface between the SPDS and the plant and cannot cause an accident. The software cannot cause equipment important to safety to malfunction. The operating characteristics of the plant and monitored equipment were not affected and no new failure modes were created.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1498 Modifications to the Containment H_2/O_2 Analyzers

Description and Basis for Change

The A-side H_2/O_2 analyzer (1C218A) had previously been declared inoperable due to excessive fluctuations in the percent oxygen indication. Initial troubleshooting revealed a failed pressure regulating valve on the sample bypass line and this valve was replaced. Excessive instrument fluctuations were still present,

however. Further analysis led to the installation of an accumulator volume in the sample pump suction tubing to dampen out pressure fluctuations within the system caused by the pump.

An additional modification was performed. Previously, if the analyzer was in operation and an isolation occurred, the pumps would remain running even though the sample inlet and outlet isolation valves had closed. To protect the pump from deadheading during such isolated conditions, a relief check valve was added to the pump discharge tubing. This valve relieves to the pump suction tubing. A manual valve was added to this line so that the relief can be isolated in case it were to fail open. The addition of the accumulator and check/shutoff valves were performed to H_2/O_2 Analyzer 1C218A under EDCP 1498. DCP 1498 provided for similar modifications to the B-side H_2/O_2 Analyzer (1C218B), with the addition of a drain valve on the accumulator.

Summary of Safety Evaluation

The containment hydrogen and oxygen analyzers provide indication of containment conditions during both normal operation and accident conditions. After a Loss-of-Coolant Accident (LOCA) the operators would use the containment hydrogen and oxygen concentrations to direct the use of the Containment Atmosphere Dilution (CAD) system to maintain the hydrogen and oxygen gas concentrations below combustible levels. The improvements made by this DCP made the H_2/O_2 analyzer system more reliable, thus ensuring that the analyzers will be functional when required to notify control room personnel of high hydrogen or oxygen conditions after a LOCA.

Installing the relief check valve introduced the possibility of the valve failing open, which would allow the sampled gasses to recirculate through the analyzer. If this happened, the situation would not go undetected since the indicated concentrations of both hydrogen and oxygen would increase steadily due to the reagent gas being recirculated through the analyzer. (The reagent gas is 100 percent hydrogen for the oxygen analyzer and 100 percent oxygen gas for the hydrogen analyzer.) Once the high hydrogen or oxygen concentration alarm was received in the control room, the operators could either take the analyzer out of service or close a manual valve in the bypass line to prevent the sample and reagent gasses from recirculating through the analyzer.

UFSAR Section 15 discusses accident analyses and the assumptions that were made for each scenario. The modification did not affect any of the design basis accident analyses, nor did it create an accident of a different type. The hydrogen and oxygen analyzers are only required to function after a design basis accident as an indication of potential containment degradation.

This modification did not involve an unreviewed safety question or change to Technical Specifications.

DCP 1503 SV7605 A&B Replacement

Description and Basis for Change

Solenoid valves SV7605 A&B are pilot valves that operate valves that isolate the air vent from the Off-Gas Carbon-Bed Vault Room to the Standby Gas Treatment System on receipt of a Secondary Containment Isolation (Group 3) signal.

SV7605A and SV7605B were located near the ceiling of the HPCI room. This location placed them in the highest temperature region of the HPCI room which shortened their qualified life. These valves were at the end of their qualified EQ life and needed to be replaced. The replacement solenoid valves were EQ qualified class 1E solenoid valves.

The replacement solenoid valves were located at a lower elevation to place them in a lower temperature region and to make them more easily accessible for maintenance and inspections. Previously, scaffolding was required to perform maintenance on these valves.

Summary of Safety Evaluation

The Standby Gas Treatment System is designed to filter and exhaust the Reactor Building atmosphere to the offgas stack during Secondary containment isolation conditions, with a minimum release of radioactive materials to the environs. This system mitigates the consequences of the accidents which have been previously evaluated in the UFSAR.

The replacement solenoid valves and the previous solenoid valves were mechanically and electrically equivalent with the exception of the elastomer used for internal diaphragms and seals. The elastomer used in the replacement solenoid valves is especially resistant to deterioration effects caused by hydrocarbons. In addition, this elastomer has the advantage of being more resistant to "dryheat". Replacing the solenoid valves improved the Standby Gas Treatment System's reliability in the event of an accident.

The solenoid valves and associated air lines were seismically mounted at a lower elevation which placed them in a lower temperature region thereby reducing the effects of heat degradation. The replacement solenoid valves and associated air lines have the same modes of failure as the previous solenoid valves and air lines. The replacement solenoid valves are no more likely to fail than the existing valves. However, should the replacement valves fail, the consequences would be the same as if the previous solenoid valves had failed.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

DCP 1504 Feedwater Check Valves - Soft Seat Removal

The feedwater check valves V-14-01 and V-14-03 serve as the in-board isolation valves for the feedwater lines which penetrate the primary containment. DCP 1422 was initiated to improve seating problems encountered with the Anchor/Darling tilting disc check valves. One of the modifications performed as part of that change was the installation of soft seats to the valve disc.

As-found Local Leak Rate Tests (LLRTs) performed after one cycle of operation with the soft seats revealed that one of the check valves had leakage greater than that allowed for these valves. Inspection revealed that both valve soft seats exhibited degradation. The soft seat from valve V-14-01 was partially eroded. The soft seat from valve V-14-03 showed little indication of erosion, however the soft seat had been compressed due to the high pressure or temperature the valve seats are normally exposed to. Based on the as-found condition, it was decided to remove the valves' soft seats to prevent any problems which might have resulted from the total or partial failure of the soft seat material.

Summary of Safety Evaluation

The check valves are installed to mitigate the consequences of an accident, and can not initiate an accident. Therefore, a modification to the check valve cannot increase the probability of a previously evaluated accident.

The modification to the check valves will not adversely impact the valves' ability to perform their function of containment isolation. The removal of the soft seats and retaining rings did not adversely effect the operation or performance of the valves. The soft seats were originally installed to assist in valve seating, however due to the erosion and shrinkage of the soft seats, the soft seats were unable to perform their intended function and provided no assistance to the valve operation. The modification did not increase the consequences of an accident previously evaluated because the soft seats were never intended to provide the primary seal upon valve actuation. The metal seat was originally, and still is, the primary seal upon valve closure. Removing the soft seats did not alter the primary metal seal. By removing the soft seats, any chance of the seat dislodging and preventing the valve from closing is eliminated.

The operation of the check valves was not altered. Anchor/Darling Valve Co. provided concurrence that the disc structural integrity will remain unaffected after the removal of the soft seats and retaining rings.

The reactor coolant pressure boundary is not affected by removing the valve soft seats.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

MM 278 Emergency Diesel Generator Air Start System

Description and Basis for Change

Several EWRs had been generated concerning various operational difficulties associated with the air start system for the emergency diesel generators. This modification addressed air filtering problems, cracked fuel lines, leaky valves on the air start system and degradation of the diesel fuel oil.

The modification replaced air bleed valves with valves less likely to leak. The copper fuel lines for the diesel powered compressor were replaced with steel tubing less prone to cracking. The air filter housings were electroless nickel alloy coated and the air filter elements replaced with a noncorroding filter element. Chicago hose connections were added to the air charging lines to facilitate a convenient temporary hose cross connect and the welded end caps on the diesel fuel oil day tank 1-1/2 inch suction line were replaced with threaded hose connection adapters.

Summary of Safety Evaluation

These modifications improved the reliability and operability of the affected equipment. The connections on the fuel oil day tanks allow fuel oil to be easily filtered, ensuring that fuel oil stability requirements are met. The coating on the air filter housings will prevent the gross deposit of corrosion products into the air start system. The new drain valves on the air filter units should be more leak tight. The stainless steel tubing should be less prone to cracking than the original copper fuel lines. These various changes should improve the operability and reduce the maintenance of the air start system, while not adversely affecting equipment important to safety.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

MM 281 Instrument Air Logic

Description and Basis for Change

The relay control logic for the instrument air compressors was designed to require a manual start signal from the control panel of each compressor. This meant that any time power was removed from the units, a manual start signal had to be given to each compressor.

Since the capacity of each compressor is more than adequate to handle normal loads only one compressor is required to run with the other two in standby status during normal operation. If power is removed from the running compressor, the air system will

depressurize to a setpoint which will initiate at least one of the standby compressors to restore system pressure. In the unlikely event of loss of power to all three compressors, none of these compressors would have automatically started to restore system pressure. An operator would have to go down to the Compressor Building to manually restart the compressor.

This modification installed a time delay relay and on/off switch on each compressor to bypass the manual start pushbutton. The time delay relay is only active immediately after a loss of power for longer than 20 msec. Once power is restored, a 20 second time delay will begin to allow the compressor time to stop. After 20 seconds, a normally-open contact will close for 5 seconds bypassing the manual start pushbutton, then return to the open position. Operation of the compressor will then proceed as normal. The on/off switch disables the time delay relay to prevent inadvertent starts during maintenance.

Summary of Safety Evaluation

This modification did not interfere with the existing control logic. The manual start feature still exists unchanged. The modification simply allows the compressor to automatically start after power is restored following a loss of power event instead of relying on an operator to manually start the compressor. The worst-case failure of this modification would prevent a single compressor from automatically starting after power is restored following a loss of power event. The compressor still could be manually started by an operator.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

PMP-0002 Honeywell Temperature Transmitter Replacement

Description and Basis for Change

The Honeywell temperature transmitters performed unreliably and required frequent maintenance. Honeywell no longer manufactured these models and spare parts were difficult to obtain. For these reasons, numerous transmitters were replaced by this modification.

Systems affected were General Service Water (GSW), Reactor Building Closed Cooling Water (RBCCW), Residual Heat Removal Service Water (RHRSW), Circulating Water, River Water Supply, Feedwater, and the Nitrogen System. The inputs to the transmitters are temperature readings from pump motors and water temperatures at various points in the systems. The transmitter outputs go to the plant process computer, a temperature indicator, a temperature switch, and temperature recorders. The temperature transmitters for the Nitrogen Make-up and Purge Systems both go to a flow recorder. The output of the Nitrogen Purge temperature transmitter also goes to a control device that regulates the operation of a control valve in the system.

Summary of Safety Evaluation

This modification replaced existing transmitters with transmitters by another manufacturer. The new transmitters perform the same function as the old transmitters by converting a resistance or millivolt signal to a current signal. The new transmitters did not affect the operation of other plant equipment. The Operator response to the instruments remains the same. The new transmitters have an output range of 4-20 milliamps instead of 10-50 milliamps. This required changing the sensing resistors in the loop devices. The 4-20 milliamp output did not affect the function or operation of any equipment. The temperature transmitters send their signals to display and/or recording devices that do not have an active role in their systems. Only the Nitrogen Purge transmitter sends its signal to a control device that has an active role. However, the new transmitters, being more reliable, will not have an adverse effect on this control valve's operation.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

PMP-0004 Power Load Unbalance Test Circuitry

Description and Basis for Change

The Power/Load Unbalance (PLU) circuitry reduces the severity of a turbine overspeed upon the loss of electrical load. A problem was identified with the PLU circuits and relays which resulted in a turbine control valve trip and subsequent reactor scram while performing routine testing. To prevent this from recurring, General Electric recommended that the power load unbalance circuitry be modified by adding a seal-in relay to the PLU test circuit. The specific function of this relay is to seal the logic in the test mode, disabling the PLU control valve trip. This relay stays activated if the 40% unbalance permissive does not clear after the test pushbutton is released. This is indicated by the PLU light remaining lit.

If, at the completion of the PLU test, the PLU light remains on, the seal-in relay remains energized and the PLU circuit is disabled. The disabling of the PLU circuit due to problems encountered during testing will avoid turbine control valve closure and the subsequent reactor scram. With the PLU protection disabled the generator load should be reduced to a point that the PLU circuit is not needed until the circuit is repaired.

Summary of Safety Evaluation

The change did not impact the normal operation of the PLU logic. If a fault is present or occurs during testing, disabling the turbine control valve closure logic prevents a turbine control valve closure and a subsequent reactor scram. Defeating this PLU anticipatory overspeed trip if a fault occurs during testing is a detectable failure. This failure would be handled in the same

manner as existing detectable failures of this logic. A failure of this logic has been analyzed in Section 10.2 of the UFSAR which states, "A single failure of any component will not lead to a destructive overspeed." Section 15.2 of the UFSAR evaluates events which result in a nuclear system pressure increase - specifically, the effects of a turbine control valve fast closure due to a power load unbalance condition. This modification reduced the probability of such an event and had no effect on its severity if it were to occur.

This modification did not involve an unreviewed safety question or a change to Technical Specifications.

PMP-0009 Extraction Steam Line Upgrade

Description and Basis for Change

During the Cycle 9/10 refueling outage, severe Erosion/Corrosion (E/C) referred to as "tiger striping" was discovered in the two, 20-inch extraction steam lines from the low pressure turbines to the 3A and 3B feedwater heaters. Tiger striping is a distinctive swirling pattern of E/C found in piping systems with two-phase flow, low dissolved oxygen content, condensate pH below 9.3, fluid temperature around 350°F, unfavorable piping geometry, and carbon steel piping material. These conditions exist to some extent in the two, 20-inch extraction steam lines with E/C. Pipe wall thickness measurements indicated that this E/C would reduce the wall thickness to below the minimum allowable thickness in the near future.

Changing the material composition of the two, 20-inch extraction steam lines was deemed the best approach for eliminating tiger striping E/C. From a metallurgical and availability standpoint, the best material for partial or complete piping replacement was P22 grade low alloy steel. This modification upgraded the two, 20-inch extraction steam lines from the low pressure turbines to the 3A and 3B feedwater heaters with P22 grade low allow steel piping.

Summary of Safety Evaluation

The only probable analyzed transient or accident that could occur as a result of an extraction steam line failure would be a loss of feedwater heating transient. The upgraded piping material has superior resistance to erosion/corrosion attack, therefore the possibility of a feedwater heater failure resulting from an extraction steam line failure was significantly reduced. The consequences resulting from an extraction steam line failure are enveloped by the existing safety analysis for a loss of feedwater heating transient and a steam line break accident. The extraction steam system is not safety-related, and does not interact with any safety-related systems. There was no effect on systems that are required to perform a safety function.

This modification did not involve and unreviewed safety question or change to Technical Specifications.

Lost Tape in the RPV

During the Cycle 10/11 fuel reload at the DAEC, a partial roll of silver duct tape was inadvertently dropped into the reactor pressure vessel. The tape was observed to drift to the feeder of jet pump #11 and was observed apparently lodged in the suction nozzle. When refuel floor personnel attempted to retrieve the tape, however, it could not be found. A camera search of the area failed to find the tape. It was assumed that the water-logged cardboard core collapsed and the duct tape was driven by the jet pump flow into the reactor vessel lower plenum region. (Shutdown Cooling was operating at approximately 4000 gpm.) Jet pump flow was verified to be normal, so the tape was not lodged within the jet pump itself.

General Electric performed an analysis of the composition and degradation process of the tape. The tape was PVC in cotton fabric with a rubber cement adhesive. The PVC was contained in the polymer backing which also held the reinforcing fabric. For this type of tape, the adhesive makes up about 70% of the tape and the fabric constitutes about 8% of the tape. The roll of tape had a 3 inch inner diameter cardboard core, was 2 inches wide and was thought to have approximately 1/4 inch of tape left on the roll. Analyses conservatively assumed 1/2 inch of tape left, consisting of 22% polymer backing (PVC).

The chemical composition of the tape was such that the tape would begin to disintegrate at temperatures greater than 200°F. Degradation of PVC produces HCl and leaves behind an unsaturated polymer. The remaining polymer is subject to further, ready degradation, especially if oxygen is present, as is the case during startup. Hydrogen and methane would be produced as well as some CO and eventually a little granulated graphite material. The HCl is the only degradation product that would be threatening to the integrity of BWR structural materials. High chloride concentrations catalyze intergranular attack, especially of creviced stainless steel, and promote IGSCC of austenitic materials.

The degradation rate of PVC is much faster at temperatures greater than 390°F. By maintaining the reactor water at a low temperature, the tape was predicted to disintegrate at a rate slow enough such that with the RWCU system operating, chloride concentrations could be kept below the 0.1 ppm limit. During this period, flow through the core region would result in mixing of the chloride and avoidance of localized high concentration areas. Also, the reactor water was tested periodically during this time to ensure the chloride levels were maintained below the limit.

General Electric also performed a loose parts analysis for the duct tape. This analysis determined that there was no potential for fuel bundle flow blockage and subsequent fuel damage because the chemical composition of the tape was such that the tape would start to disintegrate at temperatures above 200°F. If the duct tape was carried by the recirculation flow up toward the core region prior to its complete disintegration, the part could go through the fuel support casting inlet orifice but would be trapped at the lower tie plate. Assuming that the tape migrated to the highest power bundle and the reactor was at rated power conditions, boiling transition would only occur if flow blockage at the lower tie plate was 86% or greater. This degree of blockage could only be achieved if the duct tape was assumed to be intact with its original dimensions and laid out flat against the lower tie plate. This event was unlikely because the dimensions of the fuel support cavity would prevent the duct tape from being fully spread against the lower tie plate surface. In addition, this analysis assumed rated conditions. Since the reactor water temperature was maintained low enough to allow for a slow decomposition of the tape, the temperatures in the high power bundle would also be significantly less than assumed in the analysis.

The lost part analysis also concluded that there was no concern for interference with control rod operation. During the period of deterioration, the cooling flow from the CRD mechanisms upward through the guide tube and design of the inlet orifices and fuel support pieces result in a low probability of tape entering into the guide tube. If, however, the tape were to somehow enter the control rod guide tube, the normal hydraulic forces are large enough to overcome any potential friction caused by the tape. Therefore, the ability to insert, withdraw or scram the control rod would not be adversely affected.

This did not involve an unreviewed safety question or change to Technical Specifications.

<u>Safety Evaluation in Support of Power Operation with 3 Steam Lines in Service</u>

The purpose of this safety evaluation was to address reactor power operation up to a nominal value of 85% with only 3 main steam lines in operation. It also addressed the required surveillance testing of turbine control valves and MSIVs with only 3 steam lines in service.

The design basis accidents for DAEC are LOCA, Steam Line break, refueling accident, and control rod drop. The consequences of these accidents were previously evaluated in terms of offsite dose consequences. It was determined that operation with three steam lines in service at reactor power levels up to 90% would not affect the probability or consequences of the LOCA, refueling accident or control rod drop.

The Steam line break analysis assumes maximum flow through a steam line external to containment, coupled with a maximum MSIV closure time. The flow through this steam line is limited by the flow restriction internal to the steam lines. Operation with three steam lines allowed higher flows in each steam line than normally associated with 100% power operation with four steam lines in service. This did not affect the maximum steam line flow that the main steam line flow restrictions will permit. Therefore, the resultant reactor coolant release external to the containment was not increased, and the offsite consequences not changed as a result of this operating condition. The steam line stresses remained well within allowable values in this operating mode; therefore the likelihood of the steam line break accident was not increased.

The limiting events evaluated during each reload for DAEC constitute the events of interest regarding the consequences of equipment malfunction. The specific events of interest for this operating mode were those that could result in greater or more rapid vessel pressurization or more rapid reactivity feedback - an MSIV closure or a load reject without bypass transient, respectively. An analysis performed by General Electric demonstrated that the MSIV closure event was less limiting at 90% power with 3 steam lines in service than the 100% 4-steam line case. The load reject without bypass event at up to 90% power was also found to be less limiting.

Reactor power was limited during turbine valve testing and MSIV fast closure testing with one main steam line secured to ensure the reactivity and pressure feedback effects would be bounded by the parameter changes normally encountered while testing with all steam lines in service.

Acceptable margin to operating and safety limits was maintained. Reactor dome pressure and turbine pressure were maintained within normal limits. Each steam line was operated with somewhat larger steam flow than the normal 100% operating case. However, this increased flow was not significant and was not limited by the steam line size. A slightly higher pressure differential between reactor dome pressure and turbine inlet pressure existed at 90% power with three steam lines in service compared to a equivalent power level with 4 steam lines in service. However, this was not significant.

This situation did not involve an unreviewed safety question or a change to Technical Specifications.

SECTION B - PROCEDURE CHANGES

During 1990, various procedures as described in the Safety Analysis Report were revised and updated. All changes were reviewed against 10 CFR 50.59 by the DAEC Operations Committee. One safety evaluation was written to support a change to plant procedures during 1990. A summary of this procedure change and its safety evaluation is provided below. No changes were made that involved unreviewed safety questions or changes to Technical Specifications.

All Special Test Procedures (SpTPs) performed in 1990 were reviewed by the DAEC Operations Committee. No unreviewed safety questions were found to exist. Summaries of these special tests and their safety evaluations are also found below.

<u>TEST/PROCEDURE</u> <u>TITLE/DESCRIPTION</u>

GMP-INST-009 <u>Hydrogen Injection Controller Setpoint Change During Coastdown</u>

This procedure outlined the steps necessary to change the hydrogen injection controller feed flow function setpoints. This was required to change the hydrogen injection rate during plant coastdown.

<u>Summary of Safety Evaluation</u>

The hydrogen injection rate can be increased by 0.1 scfm up to a maximum of 5.0 scfm per loop (10 scfm total) with the flow controller via keypad entry. The DAEC is analyzed for operation with an injection rate up to 10 scfm. The activities outlined by this procedure were completely enveloped by the existing evaluation.

The increased injection rate required during end-of-core-life conditions, <u>i.e.</u>, "coastdown" did not modify the function or affect the operability of any safety-related plant systems or equipment. The potential for and consequences of fires or explosions due to uncontrolled releases of hydrogen or oxygen was not greater than previously evaluated because the existing system is designed for operation up to 10 scfm.

The performance of this procedure did not involve an unreviewed safety question or change to Technical Specifications.

SpTP No. 158 <u>HPCI Performance and Improvement</u>

The HPCI System is provided to ensure that the reactor is adequately cooled to meet the design basis in the event of a small break LOCA that does not result in rapid depressurization of the reactor vessel. This Special Test Procedure provided a means of controlling and documenting work, testing and data collection on the HPCI System. In this way, the overall reliability of the HPCI System could be improved.

The Special Test Procedure was divided into three phases. The First Phase was testing performed prior to entering an LCO. This testing collected data in such a manner that the operability of HPCI was not compromised. The Second Phase of testing was performed after the HPCI System was taken out-of-service. The Third Phase performed testing which reverified the operability of the HPCI System prior to return to service.

Summary of Safety Evaluation

The HPCI System is provided to assure the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break and loss-of-coolant which does not result in rapid depressurization of the reactor vessel. The HPCI System permits the reactor to shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The procedure had no effect on this function during the First Phase of the SpTP. The Second Phase placed HPCI out-of-service, and a Technical Specification Limiting Condition for Operation (LCO) was entered. The last phase of the SpTP ensured that HPCI could meet its design intent. During the Second and Third Phase of this Special test, the HPCI System was inoperable and therefore subject to the compensatory measures dictated by the HPCI LCO contained in Technical Specifications. This LCO requires operability of systems designed to back-up HPCI in the event of an accident. Therefore, activities performed during the Second and Third Phase did not decrease the margin of safety as defined in the bases of any Technical Specifications. The lube oil Fill and Drain Down Characteristics testing, as in the First Phase, has no impact on the HPCI System or on any of its associated systems.

This Special Test performed no function relative to system interactions which would have adversely affected any existing accident scenarios or created any new accident scenarios. This special test did not create the possibility of a malfunction of equipment important to safety of a different type than previously evaluated in the FSAR. No new failure modes were created for the HPCI System. The test did not increase the consequences of an accident previously evaluated in the FSAR.

The performance of this Special Test Procedure improved the overall performance of the HPCI system in meeting its design intent and did not involve an unreviewed safety question or a change to Technical Specifications.

SpTP No. 160 Loss of Instrument Air System Tests

This test was performed in response to Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment", to demonstrate that each system would respond to Loss of Instrument Air as designed. To perform these tests, an isolation valve to the component being tested was closed, cutting off the air supply. The air pressure was then reduced.

The test was performed by opening the drain both slowly and rapidly. The component response and any unusual occurrences were noted. Following the test, the drain taps were closed and the isolation valve reopened and verified to be open.

Summary of Safety Evaluation: Total failure of the compressed air system will not affect the operation of safety-related air-operated equipment because these equipment have back-up accumulators, back-up air compressors or are designed to fail in a safe position following a loss of air event. This test simply verified that the component would indeed fail in its designed position when air supply was isolated and air pressure bled off. Any component that failed to respond as designed would have been declared inoperable, and an LCO entered if required by Technical Specifications.

Performance of this Special Test did not involve an unreviewed safety question or a change to Technical Specifications.

SpTP No. 162 Containment Atmosphere Dilution Hydrogen and Oxygen Analyzer Span Gas Concentration Affects on System Sensitivity and Accuracy

The purpose of this test was to determine the effect changes in the CAD analyzer O_2 and H_2 span gas concentrations would have on system sensitivity and accuracy. Changes will eventually be made on a permanent basis to meet Iowa Electric's Reg. Guide 1.97 commitments. Results of this test will also be used to provide guidance for revising the plant Emergency Operating Procedures (EOPs) with regards to H_2 concentration entry conditions and action levels.

Summary of Safety Evaluation: The containment hydrogen and oxygen analyzers are not considered in the analysis of the consequences or probability of the design basis accidents. The system was operated within it's capabilities and specifications as outlined in the UFSAR. In accordance with the Technical Specifications, one train of the H_2-O_2 analyzers was tested at a time and each train was returned to its pretest condition following testing.

Performance of this special test did not involve an unreviewed safety question or a change to Technical Specifications.

SpTP No. 163 Heat Exchanger Performance Monitoring for NRC Generic Letter 89-13

NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment", included in its requirements the need to verify adequate performance of safety-related heat exchangers. Therefore, Special Test Procedure (SpTP) 163 was developed to accomplish this testing. This Special Test Procedure was broken down into subsections A through K for individual components. Each subsection utilizes the similar methodology of measuring component cooling flow and

component inlet and outlet temperatures, or component differential pressure.

Summary of Safety Evaluation

The ESW system and RHRSW system are required to function in support of the ECCS systems during a Loss of Offsite Power (LOOP) and/or a Loss of Coolant Accident (LOCA). The performance of this SpTP did not render either of these systems inoperable, nor did it in any way degrade the system's ability to perform its respective safety-related function.

The successful performance of the ECCS and support systems prevents any unacceptable consequences from occurring. No component's operability was affected, and no other adverse operating conditions were imposed during its performance. This SpTP only verified the heat removal capability and individual flows of ESW and RHRSW components.

The performance of this SpTP did not increase the likelihood of an equipment malfunction. External, non-intrusive instrumentation was utilized as much as possible, and a separate Temporary Modification was issued for any instrumentation which temporarily invaded the systems pressure boundary. The different subsections of this SpTP were performed at different times such that only one component at a time was tested. Therefore, even if a component inoperability should occur during the performance of this test, the consequences of that inoperability would be no different than an inoperability that might occur during routine operations, and the appropriate Limiting Condition for Operation (LCO) would be entered.

The margin of safety defined in the Technical Specifications is based upon a calculated heat removal rate for each component. This SpTP only verified the performance of each component, and did not reduce the component performance or margin of safety.

Performance of this special test did not involve an unreviewed safety question or a change to Technical Specifications.

SpTP No. 164 Reactor Water Cleanup and Reactor Recirculation Systems Chemical Decontamination.

The chemical decontamination of the Reactor Water Cleanup (RWCU) and Reactor Recirculation (RRS) systems used a process which utilized a low-oxidation-state metal ion as a reducing agent to attack iron-rich oxides typical of the BWR crud deposits that contribute to the high radiation fields associated with the primary loops. The RWCU chemical decontamination also included a nitric permanganate (NP) step. This is an oxidizing pre-treatment used for the removal of chromium-rich oxides.

The RWCU and RRS chemical decontaminations were performed when the respective systems were out of service. RWCU was physically isolated by installing temporary flanges. The RRS chemical

decontamination was performed after the core was off-loaded and the RPV level lowered below the recirculation pump suction nozzles to preclude the dilution of the solution. To prevent the chemical decontamination solution from entering the RPV due to human error, automatic isolation of the RRS from the chemical decontamination equipment was provided by air-operated valves and redundant level transmitters set at elevation 782'-0", which is approximately 6" below the bottom of the N1A/N1B nozzles and the attached horizontal runs of RRS suction piping.

The RWCU chemical decontamination was performed prior to the RWCU pipe replacement project as a technique to keep the workers' dose ALARA. The RRS chemical decontamination was performed as early as practical in the refuel outage for the same reason.

Summary of Safety Evaluation

Since the chemical decontaminations were performed during plant shutdown with physical isolations or the core off-loaded, the only remaining concern was the effect on the pressure boundary materials with respect to the probability of a LOCA. Failure of pressure boundary material was previously evaluated for the effects of arbitrary high energy line breaks and the consequences of LOCAs. Nothing in the chemical decontamination process invalidated these analyses or required them to be expanded.

It was determined that the solutions would be removing the oxide (crud) layer from the piping/components, and would probably not reach the base metal. If the solutions were to wet the base metal, there would be no adverse effects on any of the metal based upon a review of reports published by EPRI and GE. It was also determined that the chemical decontamination solutions would not contact any equipment that is important-to-safety or equipment used to mitigate the consequences of any accident. The chemicals were removed by ion exchange prior to disconnecting the chemical decontamination equipment. The chemical decontaminations did not modify any systems or equipment that are important-to-safety.

Performance of this special test did not involve an unreviewed safety question or a change to Technical Specifications.

SpTP No. 165 Secondary Containment Bypass Flow Test Data

The purpose of this test was to quantify the amount of Secondary Containment air flow bypassing the Standby Gas Treatment (SBGT) System during Secondary Containment isolation via the Main Plant Exhaust Stacks. The driving force for this bypass flow is provided by the Main Plant Exhaust Fans. These fans are downstream of the Reactor Building Vent Shaft Isolation Dampers and provide enough differential pressure across the dampers and vent shaft to create bypass flow.

The bypass leakage was quantified by isolating Secondary Containment and testing under two conditions:

1. Main Plant Exhaust Fans on and maintaining normal upstream pressure.
2. Main Plant Exhaust Fans on and equalizing its upstream pressure with the Reactor Building Vent Shaft pressure.

The first condition provided a line up in which bypass flow was present. The second condition prevented bypass flow. The difference in the two SBGT flow rates represented the bypass leakage to the Main Plant Exhaust Stacks.

Summary of Safety Evaluation

This special test involved the Reactor Building, Turbine Building and Radwaste HVAC systems as well as the SBGT System. The test initiated a Group III/Secondary Containment isolation, secured both the Turbine Building and Radwaste HVAC, and adjusted the Main Plant Exhaust Room pressure and SBGT flow rate. A prerequisite for this SpTP was that the plant be placed in cold shutdown, and be able to support a loss of Turbine Building HVAC. This prerequisite assured that neither the Group III isolation nor the loss of Turbine Building HVAC would initiate a transient.

All equipment used in this test was operated within normal means except for the inlet dampers to the Main Plant Exhaust Fans. These dampers were disconnected from their pneumatic controller and reconnected to a pneumatic calibrator to allow manual control of the dampers. These dampers and the Main Plant Exhaust Fans are non-safety-related. The dampers provide a ventilation exhaust path for the Turbine Building, Reactor Building, SBGT general area, and Heat Pump Room. Because the Turbine Building HVAC was secured and the Reactor Building HVAC was isolated during the SpTP, no main plant exhaust path was needed. Both the SBGT general area and Heat Pump Room HVAC systems are non-essential, but because they are supplied by a fan dedicated to the two rooms, adequate air flow was provided. Though the normal exhaust was limited by the manipulation of the Main Plant Exhaust Dampers, exhaust was established through inherent leakage paths (doors, penetrations, etc.). Therefore, manual manipulation of the Main Plant Exhaust Dampers was of no consequence to the plant.

The SpTP required the plant to be in cold shutdown to provide adequate margin in heater bay temperatures and prohibit a spurious Group I Isolation upon securing the Turbine Building HVAC. A Group III Isolation was also initiated by the SpTP but did not increase the probability of an accident. All systems isolated by Group III valves and dampers remained unaffected when the plant was in cold shutdown. SBGT flow rate was manually adjusted during this SpTP, but the required 0.25 inch H_2O Reactor Building to atmosphere differential pressure was maintained

throughout the test. Radwaste HVAC was secured during the test. This was judged non-consequential to safety and did not increase the probability of an accident.

The only safety-related systems operated by this SpTP were the SBGT and PCIS Group III/Secondary Containment Isolation. Both of these systems were placed in the configuration required for accident mitigation. All safety-related equipment used by this SpTP were operated within their normal parameters. No modifications to safety-related equipment took place. All equipment addressed in Technical Specifications were operated within normal parameters. This equipment was placed in the mode of operation required for accident mitigation, which assured performance of its safety function.

Performance of this special test did not involve an unreviewed safety question or a change to Technical Specifications.

SpTP No. 166 Control Building HVAC Wind Correlation Testing

The purpose of the test was to collect data for use in determining wind effects on Control Room differential pressures. Data was collected over a wide range of wind speeds and directions by manipulating the Control Building HVAC System.

Summary of Safety Evaluation

The effects of any temperature increase in the Control Building were evaluated. It was determined that the temperature rise would be small and would not adversely affect any Control Building equipment. The expected temperature rise during the test was within the Control Building HVAC envelope. NUREG-CR-1580 and ASHRAE guidelines were reviewed and it was determined that increased operator physiological stress would not result from the small increase in temperature.

The safety-related equipment in the CBHVAC envelope is qualified for temperatures up to 104°F. Any temperature rise during the short time-frame of the test would be small and have no adverse effect on the safety-related equipment or personnel within the CBHVAC envelope. If a high radiation alarm on the radiation monitors has been received during the test, the operator had been given instructions to return the affected Standby Filter Unit (SFU), Return Fan and Air-Conditioning Unit to service.

If other safety-related equipment had coincidentally failed during performance of the test, there would have been no resultant increased radiological consequences because of the test. The standby SFU train was still available for operation and the Operators could have aborted the test at any time with no resultant adverse effects on safety-related equipment.

The effect of the test on the UFSAR Chapter 15 accident analysis was also evaluated. The Control Building HVAC System does not play a role in the initiation of these accident scenarios. The

test did not alter any assumptions previously made in evaluating the radiological consequences of an accident as described in the UFSAR. There were no new accident scenarios created by performance of this special test.

The performance of this special test did not involve an unreviewed safety question or change to Technical Specifications.

SpTP No. 167 <u>Reactor Water Cleanup System Area Differential Temperature Setpoint Determination</u>

During the Cycle 10/11 Refueling Outage, one of the inputs to RWCU differential-temperature sensor TDS-2743F was relocated to better sense inlet ventilation temperatures and improve reliability of the RWCU area high differential temperature trip. Relocation of this temperature element required resetting the trip setpoint to 10°F above the 100% operation normal ambient differential temperature. The purpose of this special test was to collect operating data on the normal ambient differential temperature between the air entering and exiting the RWCU Heat Exchanger and Pump Rooms, and determine a new trip setpoint for TDS-2743F. No physical changes were made to the RWCU or Steam Leak Detection System other than the change to the setpoint of TDS-2743F.

<u>Summary of Safety Evaluation</u>

This special test did not alter the operation of the plant, RWCU system or steam leak detection system with the exception of setting the high differential temperature setpoint of TDS-2743F to approximately 50°F for the duration of the special test. The TDSs are designed to promptly isolate the RWCU system in the event of system leakage in the RWCU Heat Exchanger area and cannot initiate a LOCA or any other accident previously evaluated in the FSAR. Temporarily raising this setpoint was required to allow restoration of the RWCU system in order to determine the normal RWCU room differential temperature to establish a trip setpoint consistent with the requirements of the Technical Specifications. The new setpoint was within the design range of the instrument and did not affect its accuracy or response.

TDS-2743F is only 1 of 6 RWCU differential temperature sensors in the Steam Leak Detection System. The remaining differential temperature sensors, the RWCU area ambient high temperature trips and the RWCU high differential flow trips were still operable and capable of sensing any leakage from the RWCU system and causing an isolation of the RWCU system during performance of this test.

Performance of this special test did not involve an unreviewed safety question or a change to Technical Specifications.

SpTP No. 168 Core Flow Calibration

On May 25, 1990, the APRM flow-biased setpoints were found to be in the non-conservative direction. This was due to the fact that the amount of recirculation driving flow needed to reach rated core flow has changed over the life of the plant. The corrective action for this deviation (LER 90-005) was to reset the flow units for the current recirculation flow needed to reach 100% core flow (49 Mlb/hr).

In response to this event and other problems experienced at other plants, GE issued SIL's 516 and 517. These SIL's discussed problems within the industry concerning core flow, jet pump flow and recirculation flow and how these indications are inter-related for both single-loop operation and two-loop operation. One recommendation of SIL 516 is to ensure that the core flow calibration procedure is performed as recommended in the GE Station Nuclear Engineer's manual. This procedure is recommended to be completed after each refueling outage, once the plant is at 100% power with rated core flow.

In reviewing plant history, it has become evident that this calibration procedure was performed during initial start-up testing but was never incorporated into the surveillance program and had not been performed since. This SpTP again performed the core flow instrumentation calibration as completed during initial start-up and determined the recirculation flow required to reach rated core flow. STP 41A018 was then performed to adjust the APRM flow units to the proper flow.

Summary of Safety Evaluation

Gathering the recirculation flow data from the APRM flow units was accomplished by connecting a meter to test jacks on the input and output terminals of the flow unit. In connecting and reading these signals, the overall flow unit output to the APRM's was not affected and the ability of the APRM's to initiate a trip was not affected. The flow-biased trip, which serves to lower the APRM trip setpoint during less than rated recirculation flow, remained operable as required by Technical Specifications during the performance of this Special Test. APRM flow-biased scrams do not initiate any accidents as described in the UFSAR, nor are they required to terminate any accident described in the UFSAR. The accidents as described in the UFSAR assume power transients are terminated by the clamped APRM 120% setpoint which is not affected by the flow bias signal. (Flow biasing serves to lower the APRM scram setpoint during conditions when core flow is less than rated. To preclude the APRM trip setpoint from being raised too high if core flow were greater than rated, the APRM trip setpoint is electrically clamped at a core power level of 120%.) In addition, the data was taken from the flow units one at a time to prevent the possibility of a reactor trip from occurring.

Performing this SpTP required that the individual jet pump differential pressure transmitters have the instrument zero reset. This involved isolating the transmitter and opening the equalizing valve. To do this, the instrument was taken out of service. While these instruments are safety-related and important to plant operation, this was acceptable since these instruments do not provide any protective function.

Taking data from the APRM flow units did not affect the ability of the APRMs to perform their safety function. They remained operable as required by Technical Specifications. If one of the APRM trip circuits would have become inoperable, Technical Specification would allow further plant operation as long as the other two APRM's in that division were operable. The APRM trip system has sufficient redundancy to allow one instrument to be inoperable per trip system. Gathering the data did not inhibit the APRMs from providing a trip signal and therefore did not make them inoperable. If for some reason an APRM had become inoperable, the Technical Specification action statement would have been complied with.

Performance of this special test did not involve an unreviewed safety question or a change to Technical Specifications.

SECTION C - EXPERIMENTS

This section has been prepared in accordance with the requirements of 10 CFR Part 50.59(b). No experiments were conducted during calendar year 1990.

SECTION D - SAFETY AND RELIEF VALVE FAILURES AND CHALLENGES

This section has been prepared in accordance with the requirements of Technical Specifications 6.11.1.e. There were no safety/relief valve failures or challenges in calendar year 1990.

SECTION E - FIRE PLAN CHANGES

No changes were made to the DAEC Fire Plan during the calendar year 1990.