U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Facility:	Monticello Nuclear Generating Station
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EXECUTIVE SUMMARY

Monticello Nuclear Generating Station, Unit 1
NRC Inspection Report 50-263/96009(DRS)

The inspection was a system operational performance team inspection and included aspects of licensee operations, engineering, and maintenance.

Operations

- Technical Specification (TS) interpretations did not violate TS, did not allow less conservative operation than the TS, and did not change the intent of the associated TS.

- The operators exhibited excellent adherence to procedures during performance of surveillances. Operating procedures were of good quality and provided acceptable instructions for operating the residual heat removal (RHR) system.

- Auxiliary operators appeared very knowledgeable about the RHR system and procedures. Performance during walk throughs of RHR procedures, including simulated performance of a procedure never actually used at the plant, was very good.

Maintenance

- Maintenance for the RHR system and components was performed well and maintenance personnel appeared knowledgeable and experienced. However, maintenance procedures and work instructions appeared to be limited, with many details left to maintenance personnel. The lack of detailed work instructions was considered a weakness.

- Poor practices in data recording and insufficient knowledge of test equipment during an instrument calibration created a potential for problems. However, system engineering involvement was very good and two-way communications were clear and precise.

- Based on the results of the walkdown, the review of open work orders, and discussions with licensee personnel, the material condition of the RHR system appeared good.

- The licensee appeared to maintain adequate awareness of performance trends and to take appropriate actions, although trending of RHR component failures and performance appeared to be limited to listing the inservice test data for the pump and valve tests required by the ASME code.

Engineering

- Calculations were found to contain questionable and undocumented assumptions as well as incorrect engineering data. Design verification activities appeared to lack sufficient rigor to identify errors and did not have the appropriate attention to detail.

Additionally, the licensee was placing increasing reliance on containment overpressure to ensure that adequate net positive suction head to the emergency core cooling system pumps existed.

- The use of the GOTHIC code for high energy line break analyses without prior NRC review and approval was questioned. The question will be forwarded to NRR for resolution.

- Licensee actions to resolve motor-operated valve voltage drop concerns appeared fairly thorough and comprehensive although considerations of the different current loadings of the RHR pumps appeared to be necessary.

- Weaknesses existed in the safety evaluation process. In two cases, insufficient information was provided to support the conclusion that an unreviewed safety question (USQ) did not exist, and, in a third case, an apparent USQ was identified by the inspectors.

- The design and test control limits exercised over surveillance 1136 were flawed in that an incorrect design limit was used and an error in a calculation, supporting the test, was not recognized and corrected prior to declaring the equipment operable. These issues appeared to be reflective of other test control problems discussed in Inspection Reports 50-263/96005, 96006 and 96008.

- The licensee's rationale for designating the Containment Spray and Shutdown Cooling subsystems as "non-safety related" in the Design Basis Document was unclear. The licensee's written arguments did not appear to focus on safety and minimized the significance of previous commitments to the NRC.

Report Details

I. Operations

O1 Conduct of Operations

O1.1 Witnessing of Initiation of Shutdown Cooling

During the inspection, on December 6, 1996, licensee operators brought the unit to cold shutdown to repair a safety relief valve exhibiting high tailpipe temperatures. The inspectors witnessed initiation of the shutdown cooling system. The shutdown cooling system was started in accordance with procedures and no problems were observed. The inspectors had no concerns regarding the system initiation. Further details on the safety relief valve repair are provided in Inspection Report 50-263/96012.

O3 Operational Procedures and Documentation

O3.1 Review of Monticello Technical Specification Interpretations (TSIs)

a. Inspection Scope

Because of recent findings at other facilities involving the inappropriate use of TSIs, the inspectors reviewed Monticello's TSIs to determine which TSIs affected the operation of the Residual Heat Removal (RHR) system and to determine if any TSIs violated the technical specifications (TS), allowed less conservative operation than the TS, changed the intent of the associated TS, or otherwise should have resulted in a change to the TS.

b. Observations and Findings

The inspectors found that Monticello had 19 TSIs in the approved TSI Manual. Of those 19 TSIs, 4 had subsequently been deleted, resulting in 15 active TSIs. None of the TSIs for at power operation directly involved the RHR system. One of the TSIs, TSI 3.5.E.1 & 2-1, dealt directly with RHR operation with the reactor in shutdown in that the associated TS provided the conditions for allowing all low pressure core and containment cooling subsystems to be inoperable and for allowing the suppression chamber to be drained.

The inspectors performed a cursory review of all of the TSIs and a detailed review of a sampling of six of the TSIs, including TSI 3.5.E.1 and 2-1. None of these six were found to violate the TS, allow less conservative operation than the TS, or change the intent of the TS. These were in contrast to the TSI discussed in Inspection Report 50-263/96008 which inappropriately changed the intent of its associated TS. Several of the TSIs were presented in the form of questions and answers about the usage of the particular TS. The associated answers were appropriately conservative and repeated positions consistent with NRC guidance such as Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Condition and on Operability."

Review of the TSIs, however, pointed out Monticello's lack of TS explicitly addressing electrical power source requirements for conditions other than run mode (operating at power). TSI 1.L-1 was written partly to address this issue of electrical power requirements during shutdown. The inspectors reviewed this TSI and determined it to be a reasonable application of the Improved BWR TS (NUREG-1433 "Standard Technical Specifications, General Electric Plant, BWR/4," Revision 1) which was an improvement on the existing TS. However, the inspectors were concerned that electrical power requirements for other than power operation had not yet been incorporated into the actual TS. This issue was discussed with the licensee and licensee representatives indicated that plans for conversion to Standard TS in a step-wise fashion were underway. However, no dates for completion of this activity were available and projections indicated it was at least a year away. The inspectors considered the issue of TS for electrical power requirements for other than power operation to be an inspection follow up item (50-263/96009-01(DRS)) pending discussion with the Office of Nuclear Reactor Regulation (NRR).

c. Conclusions

Based on the sample reviewed, the inspectors concluded the TSIs did not violate TS, did not allow less conservative operation than the TS, and did not change the intent of the associated TS. One item involving electrical power requirements in other than power operation was identified that may warrant a TS change.

O3.2 Review of Operating Procedures

a. Inspection Scope

The inspectors reviewed the operating procedures and alarm response procedures for the RHR system, as listed in Attachment Q, and walked through the procedures using a system drawing.

b. Observations and Findings

The inspectors observed that modifications, reviewed by the engineering team members, were incorporated into the operations procedures. The inspectors noted that the procedure had a note informing the operators that a level change could be expected when going on shutdown cooling. The inspectors discussed the note with the shift supervisor, and the system engineer. Based on the discussions, the intent of the note appeared to be good; this was to warn the operators that a level change could occur and to take appropriate actions. However, the inspectors considered that the note could be misread to imply that the level change was normal and to be expected. Following the discussions, the system engineer stated that he planned to revise the procedure to better reflect the intent of the note, as well as to make several other minor corrections.

The inspectors also noted that the procedure required isolating and blocking closed the minimum flow valves whenever the plant was in cold shutdown. The inspectors were informed that the valves were blocked closed to prevent recurrence of a valve misalignment which resulted in a partial vessel drain down. The

inspectors noted that the procedure contained appropriate steps to remove the blocks and ensure the valves were capable of opening prior to restarting the unit; however, they were concerned about the consequences if a block was not removed. This concern was discussed with the system engineer who acknowledged the adverse consequences should a block remain in place during power operation and the pump be required to operate. The engineer stated that the consequences of the block remaining in place were evaluated prior to making the procedure modification, and it was determined that sufficient procedure controls existed to prevent that from happening. The inspectors acknowledged the system engineer's reasoning, as the procedure did contain multiple steps and warning regarding removal of the blocks.

The inspectors also noted an inconsistency between operations manual Sections B4.1 "Primary Containment" and C.5-3403 concerning the torus water level instrument zero. The first document stated instrument zero was at elevation 910 feet while the second document claimed instrument zero to be elevation 910.7 feet. This inconsistency was identified to the system engineer.

c. Conclusions

The inspectors concluded that the operating procedures were of good quality and provided acceptable instructions for operating the RHR system.

O3.3 Review of Emergency Operating Procedures

a. Inspection Scope

The inspectors reviewed the emergency operating procedures (EOPs), including those steps which detailed operation of the RHR system in the shutdown cooling mode following an event which required full injection of the standby liquid control system to ensure subcriticality.

b. Observations and Findings

The inspectors noted that the EOPs cautioned the operators to watch for an increase in power when initiating a cool down, and to terminate the cooldown if a power increase occurred. The licensee stated that any increase in power would be momentary, occurring as the unborated water in the shutdown cooling lines first entered the downcomer and mixed with the borated water already present. The licensee noted that the NRC had reviewed the mixing issue in great detail during review of Revision 4 of the boiling water reactor EOPs and referred to the NRC safety evaluation report (SER). Although the mixing issue reviewed in the SER had to do with going from hot standby to hot shutdown, the inspectors observed that the actions to be taken would also apply to initiating cold shutdown through the shutdown cooling portion of the RHR.

c. Conclusions

The inspectors concluded that the EOPs contained sufficient guidance to handle going to cold shutdown with core subcriticality being maintained by boron.

O4 Operations Staff Knowledge and Performance

O4.1 Witnessing of Emergency Core Cooling System (ECCS) Pump Motor Cooler Flush Surveillance

a. Inspection Scope

The inspectors witnessed auxiliary operators perform surveillance 1339 "ECCS Pump Motor Cooler Flush" on the A train ECCS pumps and the B train core spray pump.

b. Observations and Findings

The inspectors observed that the auxiliary operators read through the procedure prior to start and had obtained all necessary equipment to perform the surveillance. The inspectors noted that the operators followed the required radiation work permits (RWP) both during performance of the procedure and during disposal of the water collected during performance of the procedure. The inspectors noted that the operators duly checked the motor cooling service water lines to the 13 RHR pump motor, although this motor was not water-cooled, and the service water lines were not connected. The operators marked the actual flushing steps as "N/A" for this motor. The inspectors discussed with the operators why the procedure was not revised to reflect that an air-cooled motor was installed. The operators believed that it was due to the possibility that the air-cooled motor could be replaced again with a water-cooled one. As the operators performed what portions of the procedure they could, and it was obvious that service water was not connected to the pump, the inspectors did not have a concern with the adequacy of the procedure.

During testing of the 12 core spray pump motor cooler, the operators were unable to obtain the required flow. The cooler was back flushed, in accordance with the procedure, but was still unable to meet the acceptance criteria. The auxiliary operator immediately reported the nonconforming condition to the shift supervisor, who initiated a condition report. The shift supervisor discussed operability of the core spray pump with the service water system engineer. The engineer referred to a previous operability review, where the reduced flow was determined to be acceptable, based on reduced river temperature.

The inspectors reviewed the condition report, 96002956, and noticed that the disposition was "use-as-is." The inspectors considered this acceptable, based on the river temperatures and the fact that the test was performed on a quarterly basis. However, the inspectors questioned the long-term acceptability, once river temperatures approached the design maximum. The inspectors noted that safety review item (SRI) 95-002 discussed long-term core spray pump operation with reduced motor cooling. This SRI was reviewed by the NRC in Inspection Report 50-263/96005 and concerns were raised about the adequacy of the testing performed to justify the conclusions in the SRI, especially for operation of the core spray pump during a design basis accident. These questions were discussed with the licensee during the exit for the above inspection report, and, in the reply to the Notice of Violation associated with this inspection report, the licensee stated "In

addition, the NRC staff requested that Monticello provide additional information to the staff prior to isolating service water cooling to the Core Spray pump motors. The test results supporting this isolation of service water cooling to the Core Spray pump motors are to be re-evaluated and safety evaluation SRI 95-002 is to be revised as appropriate prior to isolating service water cooling to the pump motors. The results of this re-evaluation will be communicated to the staff."

c. Conclusions

The inspectors concluded that the operators performance of the surveillance was skilled and that the failure of the 12 core spray pump motor cooler flush was appropriately handled. However, the inspectors were concerned regarding long-term disposition of the nonconforming condition, given the licensee's response to previous NRC concerns on isolation of the core spray motor cooling.

O4.2 Walk-through of Special Procedures with Auxiliary Operator

a. Inspection Scope

The inspectors walked through performance of two RHR special procedures with an auxiliary operator in order to determine the operators' familiarity with RHR components and location of special equipment. Accessibility of the components and adequacy of emergency lighting along the operators' path were also evaluated. The special procedures chosen for the walk-throughs were: "Venting RHR System Discharge Piping-With S/D Cooling in Service" and "Emergency Fuel Pool Cooling." The first procedure was performed on a routine basis, while, according to the operator, the second procedure had never been performed at the plant.

b. Observations and Findings

The inspectors observed that the operator was very familiar with the first procedure. The operator stated that it was performed routinely, as part of putting the RHR system into the shutdown cooling mode. The operator explained to the inspectors where controlled copies of the procedures were kept and verified that the inspectors' copy was the latest revision prior to beginning the walk-through. The operator explained which RWP was to be used and followed the requirements of the RWPs. In some cases, in lieu of actually entering a contaminated area, the operator was able to point to the valves and satisfactorily describe exactly where the valves were located and how they would be reached, including the required protective clothing and what the significant radiation hazards were in the room. While most of the valves could be reached without climbing on pipes or equipment, one set was difficult to reach. The operator demonstrated how he could perform the task without use of special equipment, but noted that a moveable ladder was staged to aid the operators in performing the venting. The operator located the ladder, as well as identifying to the inspectors its normal storage space. Emergency lighting appeared to be acceptable to light the operators' path for all the vent valves.

The operator was not familiar with the second procedure, as it was not routinely performed. Nevertheless, he was able to walk through the procedure quite capably.

The first step required removal of some sluice gates from the spent fuel pool. Although access to the pool area was extremely limited, due to work on the reactor building roof, the operator described, as best he could, how the gates would be removed, both normally, and while the repair work was underway. The operator noted that there would be sufficient time to allow items to be moved out of the way, and access to the sluice gates provided. The operator was able to follow the procedure, although on one occasion, he called another auxiliary operator for directions to a particular valve after he failed to locate it.

c. Conclusions

The inspectors deemed that the auxiliary operator was very knowledgeable about the RHR system and procedures. His performance on the walk throughs, including performance of a procedure not normally used at the plant, was very good. The inspectors had no concerns in this area.

O4.3 Witnessing of RHR Pump and Valve Operability Surveillance

The inspectors witnessed performance of portions of surveillance 0255-04-IA-1, "RHR Pump and Valve Tests," from both the control room and the RHR room. The inspectors noted good two-way communication, including use of repeat-backs, and careful adherence to the procedure. The system engineer was present in the control room for the test. The inspectors had no concerns regarding performance of the surveillance.

O5 Operations Staff Training and Qualification

O5.1 Operator Training on RHR

The inspectors reviewed several training procedures and interviewed a training and simulator instructor. Based on statements made by the instructors, training on the RHR system, and all its modes, was taught fairly infrequently; the last time being approximately five years ago. However, training on specific portions, such as engaging shutdown cooling and implementation of EOPs were taught more frequently in both class room and simulator. During review of the RHR training lesson plan, the inspectors noted one step, requiring closure of two valves, that did not agree with the system operating procedure. This discrepancy was discussed with the system engineer as well as the training instructors and it was determined that the lesson plan was in error and did not reflect a modification made several years ago. The instructors noted that the lesson plan would be revised to remove the step. The inspectors had no further concerns regarding training.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Review of Maintenance Work Orders

a. Inspection Scope

The inspectors reviewed lists of maintenance work orders (WOs) and maintenance work request authorizations (WRAs) for RHR maintenance work either to be worked or completed during the last three years. The inspectors selected and reviewed a number of the WO and WRA packages from the lists. Questions and noted issues were discussed with licensee personnel.

b. Observations and Findings

During the review of closed maintenance WO packages, the inspectors noted that many packages contained limited instructions for performing the required maintenance. The maintenance appeared to have been performed properly, as evidenced by satisfactory post maintenance test reports. Discussions with licensee personnel indicated that the satisfactory completion of work was due to experienced maintenance personnel and involvement and assistance by the RHR systems engineer. The inspectors also determined that maintenance personnel did little or no trending of equipment or component failures; this was performed almost entirely by the system engineers on an informal basis. However, the maintenance department did trend maintenance related performance indicators.

c. Conclusions

The inspectors concluded that maintenance for the RHR system and components was performed well and maintenance personnel appeared knowledgeable and experienced. Maintenance procedures and work instructions appeared to be limited, with many details left to maintenance personnel. The lack of detailed work instructions was considered a weakness. However, post maintenance testing records, included in the work package, indicated that equipment was properly repaired and that the equipment would perform its intended function.

M1.2 Witnessing of Safeguard Bus Degraded Voltage Surveillance

a. Inspection Scope

The inspectors observed the Safeguard Bus Degraded Voltage Protection-Relay Unit Calibration and reviewed the completed procedure.

b. Observations and Findings

The inspectors observed some minor difficulties. The technician initially had difficulty in resetting a relay unit that was found slightly outside specifications. Because another person, now retired, had usually performed the calibrations, the remaining technicians had only infrequently performed this procedure. This resulted

in inadequate skill of the craft knowledge to supplement the procedural deficiencies. In this case, the test procedure did not provide guidance on what input ranges were necessary for the calibration such that the test equipment was not dialed down to a sensitive enough input until it became clear proper results could not be reached. Additionally, the technician did not exhibit good practices in recording information as evidenced by test jumper numbers not being recorded when the jumpers were installed. Fortunately, just before the test jumpers were to be removed, the technician observed the missing information and completed the entry.

However, the inspectors noted that the system engineer was very involved with the in-plant calibration and two-way communications were clear and precise when steps of the procedure were performed.

c. Conclusions

The inspectors concluded that poor practices in data recording and insufficient knowledge of test equipment during an instrument calibration created a potential for problems. However, system engineering involvement was very good and two-way communications were clear and precise.

M2 Maintenance of Facilities and Equipment

M2.1 Material Condition of the RHR System

a. Inspection Scope

The inspectors walked down selected portions of the RHR system and reviewed open maintenance work requests written on system or component deficiencies.

b. Observations and Findings

The inspectors generally noted a good material condition during the walkdowns. No liquid leaks were observed either during the walkdowns or during witnessing of RHR system surveillances. A minor problem was noted where a ladder, accessing a contaminated area, was not properly marked. This was brought to the attention of the radiation protection department, and was promptly corrected. Additionally, during a walkdown of the B RHR room, the inspectors observed that the strut paddles for both minimum flow valves appeared to be touching the clamps at both ends. This condition was brought to the attention of the system engineer. The condition was analyzed, the supports determined to be operable, and a condition report and work order to restore the struts were generated.

As the licensee does not tag components requiring repair in the field, the inspectors reviewed a list of the open WOs on the RHR system. The list contained four WOs requiring minor maintenance. Two of these WOs were selected and reviewed; the minor classification appeared to be proper. Discussions with licensee personnel confirmed the inspectors' general impression regarding good material condition of the RHR system.

c. Conclusions

Based on the results of the walkdown, the review of open work orders, and discussions with licensee personnel, the inspectors concluded that the material condition of the RHR system was good.

M2.2 Trending of RHR Component Performance

a. Inspection Scope

The inspectors reviewed equipment and component trending information provided by the RHR system engineer. This information was limited to the trending of inservice testing information of pumps and vaives required by the ASME code. Trending in accordance with the Maintenance Rule was not evaluated.

b. Observations and Findings

The inspectors noted the records consisted of lists of pump and valve test data for several years. Trends were not documented or discussed in the information provided; and, according to the system engineer, trending was performed by visual comparison of the lists. The inspectors discussed the results with the system engineer, who was extremely knowledgeable about the pump performance. The engineer noted that a pump was recently refurbished due to its declining performance trend. The inspectors verified that the pump acceptance criteria took both the TS and ASME Code limits into consideration. Licensee personnel stated that no valve trends had been noted in recent years. The inspectors reviewed the last four tests, covering the last year, and confirmed that no adverse trends existed. However, the inspectors noted that as of the end of the inspection, neither the system engineer or the inservice testing (IST) engineer had reviewed and signed the September 1996 RHR Pump and Valve Test 0255-04-1A-1, Revision 40, which was completed September 21, 1996. Additionally, the inspectors noted that the December 1995 test results had not been reviewed by the IST engineer, although the results were reviewed by the RHR engineer and were archived with the missing signature.

c. Conclusions

Although trending of RHR component failures and performance was limited to listing the inservice test data for the pump and valve tests required by the ASME code, the licensee was maintaining awareness of performance trends and taking appropriate actions.

M3 Maintenance Procedures and Documentation

M3.1 Maintenance work Instructions

a. Inspection Scope

The inspectors reviewed a number of maintenance procedures and WO packages involving maintenance on the RHR system. Questions and noted issues were discussed with licensee personnel.

b. Observations and Findings

During review of the procedures, the inspectors noted that the term "should" was used extensively. The inspectors noted that administrative procedure 4AWI-01.01.01, "Administrative Controls Program" stated that the term 'should' was used to state recommendations. Based on this definition, the inspectors were concerned that many Monticello maintenance procedures were only recommendations rather than required work methods. This concern was relayed to maintenance management, who stated that the term indicated methods that management required to be used.

The inspectors noted that some maintenance WOs did not appear to contain adequate instructions to perform the work. A number of WOs contained the statement "Investigate and Repair." Other WOs indicated what needed to be done but provided no instructions for doing it. For example work order number 94-05486 for repair of a motor-operated valve only contained the work instructions "Replace limit switch," without providing any steps to ensure proper limit switch alignment and calibration. Additionally, several instructions and procedures contained the statement "steps can be performed in any order;" although it was apparent that some steps could not be performed out of ordar.

Discussions with licensee personnel indicated that additional work instructions were considered unnecessary because of knowledgeable craftspeople performing the work or the written instructions were supplemented by verbal instructions from the cognizant system engineer. However, the calibration effort discussed in Section M1.2 indicated to the inspectors the potential problems that could occur should the workers retire or leave.

c. Conclusions

The inspectors concluded that overall maintenance work instructions and records were weak. The utilization of experienced personnel and the involvement of knowledgeable system engineers prevented this weakness from becoming a serious problem.

M3.2 Rev' w of RHR Pump Vendor Manual

a. Inspection Scope

The inspectors reviewed vendor manual NX-7905-18, "RHR Centrifugal Pumps 12X14X14-1/2 CVDS."

b. Observations and Findings

The controlled copy of the vendor manual for the RHR pumps was obtained from the system engineer. The inspectors noted that the vendor manual binder contained three loose vendor supplied changes which were not formally incorporated into the manual. The system engineer stated that he received and reviewed changes to the vendor manuals for components in the RHR system. Significant changes would be incorporated promptly but minor changes might be held until two or three changes accumulated before the manual was formally updated. The engineer stated that, since the systems engineers prepared most of the maintenance work orders for their assigned systems, the engineers were aware of work to be performed on the assigned system. Based on this, there was little chance that an outdated vendor manual would be used for component repair.

c. Conclusions

Based on the review of one vendor manual and discussions with licensee personnel, the inspectors considered the control of vendor manuals to be acceptable due to the extensive involvement of system engineers in system maintenance activities.

III. Engineering

E1 Conduct of Engineering

E1.1 Net Positive Suction Head (NPSH) Calculation Review

a. Inspection Scope

The team reviewed calculations pertaining to the NPSH for the RHR pumps to verify technical adequacy, accuracy, and compliance with NRC requirements and licensee commitments. Monticello was not committed to Regulatory Guide (RG) 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps." On that basis, similar to other Mark I designs, the licensee's NPSH calculations used containment overpressure.

b. Observations and Findings

General Electric (GE) Calculation EqDE-34-0687, "Core Spray System Operational Capability Report," July 1987, determined the available NPSH for the Core Spray (CS) pumps under design basis conditions. This was considered a bounding case calculation, since the CS pumps required greater NPSH than the RHR pumps. As Monticello was not committed to RG 1.1, credit for overpressure was taken in performing the calculation. The licensee only took credit for half the overpressure

considered to be available, because the analyses maximized containment pressure rather than minimized it.

In March 1996, the licensee apparently realized that the 1987 NPSH calculation was no longer valid, due to the design change discussed in Section E1.8. Now, however, the peak suppression pool temperature was 19°F higher than the 1987 value, based on additional containment analyses. To address this deficiency, the licensee reviewed the 1987 calculation, and "pencilled-in" the necessary changes on a copy of the 1987 calculation. Although it was initialed by the preparer and verifier on March 14, 1996, this "revision" to the calculation was not performed in accordance with the licensee's QA program requirements and officially did not exist. The team became aware of this document after asking for the basis of the NPSH for the current operating condition. A copy was obtained from the personal files of the engineer involved. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be taken to verify or check the adequacy of the design, and that changes be subject to design control measures commensurate with those applied to the original design. The design changes made in the March 1996 revision to EqDE-34-0687 were not subject to design control measures commensurate with those applied to the original design. This is considered an example of a violation of Criterion III (50-263/96009-02(DRS)).

In response to the team's requests for a NPSH calculation valid for the current design configuration, the licensee provided a contractor's calculation V609.000.00001, "Low Pressure Emergency Core Cooling System (ECCS) Net Positive Suction Head," Revision 1, January 2, 1997. Detailed portions of the calculation were not provided to the team, therefore the inspectors did not review it; however the results of Case 2, the worst case of the four runs provided to the inspectors, did show approximately a three foot margin between the available and required NPSH for the CS pumps.

<u>Northern States Power Calculation CA-96-090, "Evaluation of ECCS Net Positive Suction Head,"</u> Revision 0, June 24, 1996, determined the available NPSH for the proposed increased reactor power condition (License Amendment Request - Supporting the Monticello Nuclear Generating Plant Power Rerate Program, dated July 26, 1996). The team identified several concerns in the calculation. However, since the calculation represented proposed rather than current conditions, the noted discrepancies did not cause immediate operability concerns.

First, the calculation used the wrong input value for the vapor pressure of water at 191°F. The value was non-conservative by approximately 0.5 feet. This was significant since the available margin given in the calculation was only 0.47 feet. This was considered another example of a violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, in that design control measures did not verify the adequacy of the calculation (50-263/96009-03(DRS)).

Second, the calculation showed that required containment overpressure for NPSH had increased. Independent calculations performed by the team indicated that reliance on overpressure had increased from an original design value of about 1.5 pounds per square inch gage (psig) to greater than 5 psig. Although Monticello's original licensing basis for use of containment overpressure was not

clearly documented, except in the TS bases for TS 3.7/4.7 as discussed in Section E1.8, credit for containment overpressure has been the topic of several recent generic communications from the NRC. Because of ongoing questions regarding the amount of overpressure that should be credited for NPSH design, this item will be forwarded to NRR for review. Pending resolution of this issue by NRR, this was considered an unresolved item (50-263/96009-04(DRS)).

c. Conclusions

The inspectors concluded that the licensee exercised poor control over NPSH calculations, both in performing an uncontrolled revision to one calculation following a change to the facility and in verifying the values used in a second calculation. Additionally the inspectors were concerned over the licensee's increased reliance on containment overpressure in order to ensure adequate NPSH to the ECCS pumps.

E1.2 Suppression Pool Drawdown Calculation Review

a. Inspection Scope

The team reviewed calculations pertaining to the amount of water that would be retained in the drywell following a design basis accident.

b. Observations and Findings

Calculation CA-93-056, "Suppression Pool Drawdown Calculation," Revision 0, May 17, 1993, determined the volumes within the reactor and containment that needed to be filled with water before it would flow back into the suppression pool. In calculation 96-90, the change in suppression pool level corresponding to this volume was subtracted from the available NPSH to represent potential design basis accident conditions. Previous NPSH calculations neglected this term and assumed that the lowest suppression pool level was the minimum value allowed by the TS. The inspectors noted that several assumptions were not documented or were unverified, and additional discussions with licensee engineers were needed to verify the adequacy of the calculation.

- The assumed pump flow rates were not documented. A portion of the retained fluid was due to dynamic effects, and flow rates were necessary parameters to determine this effect.

- The assumed water height, to account for the dynamic damming effect between the drywell and vent headers, was found to be non-conservative. The inspectors' independent, rough calculation demonstrated that the assumed height of 6 inches did not provide sufficient head to produce the assumed flow.

- The calculation contained a non-conservative undocumented assumption for the relationship between the suppression pool volume and pool height. The calculation assumed a linear relationship, which was incorrect because of the sloped sides of the suppression pool. The inspectors performed an

independent calculation and concluded that the assumption resulted in a three percent error at the calculated drop in level.

- The calculation assumed that the torus "ring header" holdup was "negligible." This assumption was initially confusing in that the calculation probably meant to say "vent header." However, the inspectors' independent calculation determined that the volume of retained water at the vent line and vent header intersections was comparable to other volumes calculated in the analysis. This potentially introduced an additional three percent error; and while the result might not be significant, it could not be considered negligible.

<u>Calculation CA-96-166, "Drywell Flooding Evaluation for Post DBA LOCA,"</u> Revision 0, December 3, 1996, was performed in response to the team's second comment discussed above. The analysis showed that the height of the vent line lip above the drywell floor was actually less than the value assumed in the above calculation, and concluded that the water would not get any deeper than previously assumed. The analysis did demonstrate, however, that the 6 inch assumption discussed above was non-conservative. The inspectors also noted several weaknesses in this calculation.

- The calculation made an undocumented assumption that the flow out of the drywell through the vent line could be determined using a standard weir flow formula. The differences between the weir configurations and the vent line opening in the drywell were not discussed. The inspectors noted that the vent line sloped 20 degrees from the horizontal and might not provide free-fall of the weir's nappe. The inspectors determined that the allowed vent line projection inside the drywell wall and the weld-overlay on the vent line edge would affect the performance characteristics of the weir crest. Also, the inspectors noted that the flow path approaching the vent line had radially oriented deflector mounting plates that disturbed the upstream flow pattern. These differences were inconsistent with the configurations used to empirically determine the weir discharge coefficients.

- The calculation used the nominal drywell radius and did not acknowledge that the construction tolerances for the vent line potentially reduced this dimension by ½ inch. Although this will would have a minimal impact on the results, neglecting this distance was inconsistent with the accuracy the calculation was claiming to achieve.

The inspectors were concerned that the licensee did not appear to recognize or be able to verify the assumptions being used in the calculations. The use of the non-conservative and non-verified assumptions listed above are considered another example of a violation of Criterion III (50-263/96009-05(DRS)).

c. <u>Conclusions</u>

Based on the questionable and undocumented assumptions within the calculations reviewed, the inspectors concluded that design verification activities lacked rigor and did not have the appropriate attention to detail.

E1.3 Different Computer Program Used To Reanalyze Outside Containment Environmental Profiles

a. Inspection Scope

The inspectors reviewed portions of the licensee's high energy line break (HELB) program.

b. Observations and Findings

The inspectors determined that Monticello used the Electric Power Research Institute (EPRI) Generation of Thermal-hydraulic Information for Containments (GOTHIC) computer program to reanalyze the licensee's outside containment HELB/ environmental qualification (EQ) temperature and pressure profiles. The licensee's current HELB/EQ licensing-basis analyses was performed using a modified version of the Reactor Excursion and Leak Analysis Program (RELAP4/MOD5) named "EDSFLOW." Monticello informed the NRC regarding use of the EDSFLOW code in a October 1980 response to Bulletin 79-01B. NRC accepted the licensee's use of the code, based upon the following statement in the June 1981 EQ SER: "The licensee has provided the temperature, pressure, humidity and applicable environment associated with a MSLB outside containment. The following areas outside containment have been addressed: [list of areas]. The staff has verified that the parameters identified by the licensee for the MSLB are acceptable."

The GOTHIC Version 4.0 computer program was developed for EPRI as a general purpose thermal-hydraulics computer program package for the analysis of nuclear power plant containments and other confinement buildings. The licensee used the GOTHIC computer program to generate revised temperature and pressure profiles at various locations in the nuclear power plant outside the containment structure. These revised profiles were used to reanalyze outside containment HELB/EQ evaluations for the licensee's rerate submittal and two plant events described in licensee event reports 96-003 and 96-008. Licensee personnel stated that a contractor had completed a benchline/comparison code verification summary (calculation 091-19407-C-3, "GOTHIC Verification," Revision 0) with satisfactory results for the RELAP4/MOD5 and GOTHIC Version 4.0 computer programs.

The inspectors determined, however, that the RELAP4/GOTHIC computer program benchline/comparison code verification summary was not submitted to the NRC for review and approval prior to the licensee performing in-plant modifications. The licensee stated they were unaware that the NRC expected the licensee to provide a detailed RELAP4/GOTHIC computer program benchline/comparison code verification summary and questioned what regulation required the submittal.

The inspectors informed the licensee about Generic Letter (GL) 83-11, "Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions." The GL's purpose was to inform licensee's about NRC's position regarding licensee qualification for performing safety analyses in support of licensing actions. The GL encouraged utilities to perform their own safety analyses since it significantly improved their understanding of plant behavior. However, the GL stated that the NRC's experience with safety analyses using large, complex thermal-hydraulic

computer codes, such as RELAP, had shown that a large percentage of all errors could be traced to the user rather than to the code itself. Therefore, in addition to providing acceptable QA practices associated with computer code development, the NRC required assurance of the technical competence of the licensees and vendors to set up, execute and properly interpret the results. The NRC did not consider it acceptable for a licensee to perform their own safety analyses without also performing their own code verification. The GL further stated that a licensee or vendor who intended to use a safety analysis computer code to support licensing actions should demonstrate their proficiency in using the code by submitting code verification performed by them, not others.

The licensee stated that, since no response was required, they did not respond to GL 83-11. The licensee further stated that they had interpreted the GL to refer to only reactor core loading.

The inspectors perceived GL 83-11 as requiring licensee's to perform code verification, and to submit that verification to NRC prior to using the code. This position was confirmed through discussions with NRR. However, because GL 83-11 did not specifically state all safety analysis computer code application cases and could support either the inspectors' or the licensee's position, this item is considered unresolved pending further review by the NRC (50-263/96009-06(DRS)).

c. Conclusion

The use of the GOTHIC code for HELB analyses without prior NRC review and approval was questioned. The question will be forwarded to NRR for resolution.

E1.4 Review of Motor-Operated Valve (MOV) Calculations

a. Inspection Scope

The inspectors reviewed calculational tabulations relating to the MOVs. The review included MOV-00 "Motor Operated Valve Program Introduction, References & Definitions" and CA-92-221 "RHR System MOV Performance Analysis."

b. Observations and Findings

While reviewing the MOVs, the inspectors raised a concern regarding conditions when worst case accident scenario conditions would be present when the motor operator for important valves such as the RHR low pressure coolant injection (LPCI) valves would be called upon to operate and may not have sufficient voltage levels to generate torque to move the valve. The worst case condition was the starting of large 4kV motors including the two RHR pumps and the CS pump on each essential bus (15 and 16). The MOV Program Performance analysis had assumed that the lowest voltage at the motor control centers would be 426 Vac. Preliminary analysis showed that under each motor's starting conditions a downward transient spike would dip the voltage for about eight seconds and the last starting CS pump motor, which was also the largest motor, with the compounding effect, could dip the voltage below 426 Vac. The licensee theorized that the MOV start of valve

movement might be delayed until the voltage recovered. This delay in starting could add seconds to the valve stroke time. To assure the valve would stroke within maximum allowed time even if the worst case conditions were present, the present surveillance valve stroke acceptance time would have to be shortened by this delay time to account for the start time delay. The licensee verified that the worst case increase in stroke time was within the affected valves' design limits and adjusted the surveillance tests.

RHR LPCI injection valves MO-2012, MO-2013, MO-2014 and MO-2015 were four of eight valves affected. These particular valves performed safety functions in both the open and closed positions: in the closed direction the valves were required to ensure primary containment integrity and LPCI system operability. In the open direction, these valves fulfilled containment cooling and LPCI functions. The other four affected valves were CS injection valves MO-1751, MO-1752, MO-1753 and MO-1754. The licensee performed preliminary analyses using existing computer modeling for MOV performance, but the inspectors identified limitations and possible nonconservativisms in the assumptions for the 4kV bus profile during these particular possible concurrent activations of large pumps and MOVs during accident scenarios. A large scale computer modeling run with several of the possible sequences would be necessary to verify both the duration and the lowest transient voltage. Among considerations would be different current load for different pumps since RHR pumps 13 and 14 were 600 horsepower (hp) while RHR pumps 11 and 12 were 700 hp. The licensee stated they planned to perform computer modeling and to analyze electrical loading effects under several different possible sequences of equipment operation under accident conditions and will relate these effects to MOV operation. This item is considered unresolved pending the licensee finishing modeling, calculations and analyses (50-263/96009-07(DRS)).

The inspectors noted that the original identification of the possible low motor control center bus voltage was made in 1992 (FOI 92-0064) and resolution was not timely. However, the proposed actions toward analyzing the transient low voltage effect on MOVs under accident scenarios appeared to be thorough.

The inspectors had an additional concern identified incidental to the MOV low voltage concern regarding whether safety-related 4 kV and 480V motors will start and accelerate with 80 percent of rated voltage applied to the motor terminals. Torque-speed analysis was performed on 4 kV ECCS motors; however, two of the RHR motors have been replaced since that analysis was performed and there was no evidence that additional 80 percent voltage starting analysis was performed for the replacement motors. This item is considered unresolved pending licensee calculations and analyses (50-263/96009-08(DRS)).

c. Conclusions

The inspectors concluded that the licensee's planned actions to resolve the voltage drop concerns appeared fairly thorough and comprehensive although consideration of the different current loadings of the RHR pumps was necessary.

E1.5 Review of Electrical Modifications

a. Inspection Scope

The inspectors reviewed two modifications 89Z021, "Effective Loss of 125 VDC on ECCS" and 92Q735, "Retork Replacement Modification."

b. Observations and Findings

The first modification dealt with the question of the availability of the 480 V swing bus breakers should there be a failure of the 125 Vdc bus which supplied control power to the breaker. The modification was initiated and performed within a relatively short time frame and some proposed features were not incorporated as initially planned. For example, the maintenance switch on the swing bus was eliminated because there was insufficient room to mount it and the relaying scheme was modified because a multi-function relay was available.

The second modification involved replacement of the Retork valve actuators with the next larger size. Because the gearing was different in the larger size actuator, two valves' stroke timing was increased from 10 seconds to 30 seconds (MO-2010 and MO-2011, torus spray valves) and four valves' stroke timing was increased from 26 seconds to 72 seconds (MO-2020, MO-2021, MO-2022 and MO-2023, drywell spray valves). The inspectors confirmed that the stroke time requirements were not specified in TS, the updated safety analysis report (USAR), or accident and transient analyses. The increases in valve stroke time did not appear to directly impact any system operability. These valve stroke times were trended from data obtained by ASME Code Section XI required periodic tests with the stoke times measured by a stop watch based on control room valve indications.

c. Conclusions

The inspectors concluded the modification process had minor problems.

E1.6 Inadequate 50.59 Review During Closeout Of RHR System Pressure Upgrade Modification

a. Inspection Scope

The inspectors reviewed Design Change Package 85M042, "RHR System Pressure Upgrade Modification," Revision 0, initiated on December 13, 1985. The design change was subsequently canceled as Revision 0, Addendum 1, on October 7, 1991, and closed out as Revision 1, on August 14, 1996. Design change (DC) 85M042 was initiated to raise the TS setpoint for the shutdown cooling supply isolation reactor pressure interlock from 75 psig to 175 psig. The modification was being made to permit the RHR shutdown cooling mode to be placed into service at a higher reactor operating pressure and temperature, reducing the "critical path" time needed to reach cold shutdown and thereby providing an economical benefit to the plant. The increase in RHR system design pressure and temperature ratings would also provide overlap of the shutdown capabilities of the high pressure coolant injection (HPCI) and RHR systems.

b. Observations and Findings

The inspectors observed that the modification appeared to be conducted in an accelerated manner. The DC package indicated that the engineering analysis was to be performed in parallel with the physical plant changes, without any justification. Physical plant changes associated with the modification were completed during May/June 1986. These included RHR system relief valves and instrument setpoint changes, as well as instrument replacements and the removal of an electrical "seal-in" on the open circuit of valve MO-2407, "RHR Discharge to Waste Surge Tank." However, when the engineering analysis was finally completed, the licensee concluded that the modification was not cost effective and canceled the DC package. The licensee's DC package closeout retained the physical plant changes installed during the modification instead of returning the plant back to the original configuration prior to DC package initiation. The inspectors noted that an extremely long period of time elapsed between when the hardware changes were made (May/June 1986) and when the DC package was completely closed out (August 1996).

The inspectors reviewed the safety evaluation, performed in accordance with 10 CFR 50.59, which accompanied the 1996 modification closeout and determined that it did not provide an adequate basis for concluding that no unreviewed safety question existed. The closed out DC package's safety evaluation relied exclusively upon the previous 50.59 safety evaluation conducted during May/June 1986 and did not provide any justification that retaining the physical plant changes, without completing the modification, did not involve an unreviewed safety question (USQ). The 1986 safety evaluation only restated negative responses to the 10 CFR 50.59 criteria and did not provide documented justification as to why a USQ did not exist. In addition, the inspectors noted that a NRC safety evaluation for license amendment 22, dated February 2, 1984, which established the 75 psig setpoint that the modification was going to revise specifically mentioned one of the relief valve setpoints which was physically modified. Neither the 1986 or the 1996 safety evaluations addressed why changing this relief valve setpoint was acceptable. The inspectors independently determined, based upon the words in the safety evaluation, that a change in the setpoint would not involve an unreviewed safety question.

10 CFR 50.59(b)(1) requires that a licensee maintain records of changes to the facility and that these changes include a written safety evaluation which provides the basis for determining that the change does not involve a USQ. Neither the 1986 or the 1996 safety evaluations provided this basis. This is considered an example of a violation of 10 CFR 50.59 (50-263/96009-09(DRS)).

c. Conclusions

Based upon the information provided, the inspectors concluded that the licensee had not provided justification that a USQ did not exist for modification 85M042 in either 1986, when the modification was partially implemented, or in 1996, when it was canceled with the changes left in place. This was considered a weakness in the safety evaluation process.

E1.7 Inadequate 50.59 Review Identified For Safety Review Item 96-016

a. Inspection Scope

The inspectors reviewed SRI 96-016, "1996 FOI Identified USAR Changes," Revision 0, Addendum 4, dated October 23, 1996. The SRI provided a description and evaluation of an USAR change that was identified from the HELB design basis document Follow-On Item (FOI) 94-0012, "Pipe Breaks at RHR, CS and SBLC Containment Penetrations," dated February 15, 1994.

b. Observations and Findings

The SRI proposed 16 changes to the USAR concerning pipe breaks at containment penetrations, which, on the surface, appeared to be mostly editorial in substance (e.g., the changes provided additional information and references for clarification, minor wording changes which supposedly did not affect the licensing- or design-bases of the plant. However, upon further review, the inspectors noted that the SRI revision was much more complicated; the licensee was actually redefining containment isolation boundaries.

General Design Criteria (GDC) 55 describes requirements for containment isolation valves; these include provisions on the number of valves required, normally one inside containment and one outside. The GDC further requires that the valve outside containment be located "as close to containment as practical." However, Monticello was licensed before the GDC were issued and was not committed to meeting GDC 55. Additionally, the listing of containment isolation valves was removed from the TS as a line item improvement. Therefore, the NRC relied upon performance of an adequate safety evaluation in order to ensure that the licensing basis for the containment isolation system was not affected.

The inspectors noted that the safety evaluation dealt with moving the containment boundary based upon 1) not having to consider a HELB due to the piping being at high temperature and pressure less than two percent of the time and 2) relaxed containment leakage testing criteria, which allowed extension of the time between surveillances, dependent upon test performance. Neither of these addressed why the licensing basis for the containment isolation system was not affected.

The inspectors noted that, although the SRI provided a "Reason" section for each identified change, not all reason sections adequately explained the basis or provided justification for the change. For example, on page 6, the reason for changing 20 gallons to 2 gallons was not adequately justified (i.e., What calculation, if any, was used to confirm this volume? What isometric drawing(s) showed the pipe location? What was the size and length of the pipe?). The licensee was able to answer each of these questions satisfactorily for this case; however no written justification was provided. The failure to provide a bases for determining that these changes did not involve a USQ is considered an example of a violation of 10 CFR 50.59(b)(1) (50-263/96009-10(DRS)).

c. Conclusions

Based upon the information provided, the inspectors concluded that the licensee had not provided justification that a USQ did not exist for the changes being made to the facility. For this one particular example, the licensee was able to orally describe the basis for the change; however this did not meet the requirements of 10 CFR 50.59(b)(1). This was considered another weakness in the safety evaluation process.

E1.8 Change in the Plant Design and Licensing Basis Involving an Apparent Unreviewed Safety Question

a. Inspection Scope

During review of the NPSH issues described in Section E1.1, licensee personnel provided the inspectors with a copy of Section 5.2 of the USAR, Revisions 12 and 13, as well as the supporting GE analysis, NEDO 30485,"Monticello Design Basis Accident Containment Pressure and Temperature Response for FSAR Update," December 1983, and NEDO 32418, "Monticello Design Basis Accident Containment Pressure and Temperature Response for USAR Update," December 1994. The inspectors reviewed these documents to determine why the 1987 NPSH calculation no longer applied to the Monticello plant.

b. Observations and Findings

Discovery of Degraded Condition by Licensee: The inspectors requested a copy of the safety evaluation performed prior to the USAR changes. Upon review of the SRI (92-030 "DBA-LOCA Containment Response/USAR DG Loading Table"), the inspectors discovered that the original issue arose out of the design basis document (DBD) program. During preparation of the DBDs, a discrepancy was noted that one emergency diesel generator (EDG) was incapable of supplying power to the core spray pump, two RHR pumps and two RHR service water (RHRSW) pumps. FOI 92-0032 noted that the original final safety analysis report originally contained a number of containment response curves, including a "worst case" study using one RHR pump and one RHRSW pump. Therefore, the licensee deemed that it was acceptable to return to the one pump-one pump configuration. This decision appeared to have been made without consideration of why the USAR was changed from the family of curves to only the two-pump mode.

The original FOI was labeled as being caused by "lack of documentation". It was determined to have no impact on operability or reportability.

Inspector Concerns: The inspectors had the following concerns with the licensee's safety evaluation and the associated FOI. These concerns centered around an apparent lack of a questioning attitude when resolving DBD discrepancies.

- The inspectors noted that page 2 of FOI 92-0032 stated that ". . .the peak pool temperature would probably be higher than that illustrated on Figure 5.2-17 and listed on Table 5.2-4 of the USAR." On page 3, under the conclusions, the following is stated: "The USAR lists a peak suppression

pool temperature of 182°F for an assumed combination of 1 CS pump, 2 RHR pumps, and 2 RHRSW pumps. A new analysis has been performed for the reduced combination of pumps that could be powered from a single EDG (i.e., 1 CS pump, 1 RHR pump and 1 RHRSW pump), and the peak pool temperature was determined to be 167.3°F." Although the conclusion noted that additional analysis "may be required," there did not appear to be any questioning, during review of the FOI, of why the reduced number of pumps would cause the suppression pool temperature to decrease rather than increase and whether the analysis results were acceptable.

The licensee did have additional analyses performed. Calculation NEDO 32418 "Monticello Design Basis Accident Containment Pressure and Temperature Response for USAR Update," December 1994, concluded that the short term containment temperature would rise by 10°F and the long term temperature by 2°F. However, the safety evaluation for revising the design basis to a one pump/ one pump configuration did not provide justification why the increase in temperature was acceptable. The safety evaluation stated: "The increase in maximum wetwell temperature above the value presently listed in the USAR has been reviewed and found acceptable. Since the designed function of the affected lines has not been significantly affected by the increased wetwell temperature, the margin of safety is not reduced."

In the "Design" portion of the safety evaluation, the following statement was made: "The new analysis reports a maximum wetwell temperature of 184°F. Configuration Management Follow-On Item Number 94-0051 was written to document the concern with some of the Core Spray, RHR, and RCIC lines having a listed design temperature of 180°F or less. Vectra Technologies has reviewed these lines and found them to be acceptable with a temperature of 184°F."

The inspectors were concerned that the change in wetwell temperature might introduce a new failure mode of some ECCS lines. Additionally, the inspectors noted that, if a decrease in safety margin exists, such as the design temperature of piping being exceeded, 10 CFR 50.59 requires that NRC determine the significance of the change.

- The inspectors determined that significant modifications were made to the plant in 1983, including installation of the RHR intertie line. Installation of this line increased the size of the large-break loss of coolant accident. This modification was submitted to the NRC for review and approval, prior to plant restart and the revised containment analyses were incorporated into Revision 2 of the USAR. It appeared that the licensee did not question why the USAR was revised to eliminate the multiple response curves or what had changed in the plant between Revisions 0 and 2 of the USAR.

- The inspectors noted that TS Section 3.5C "Containment Spray/Cooling System" states "A containment spray/cooling subsystem consists of the following equipment powered from one division:

2 RHR Service Water Pumps
1 Heat Exchanger
2 RHR Pumps
Valves and piping necessary for: Torus Cooling & Drywell Spray"

The TS also contain the following definition "Operable - A system, subsystem, train, component or device shall be Operable or have Operability when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electrical power sources, cooling or seal water, lubrication, or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s)."

After it was ascertained that one division of the emergency electrical power system was incapable of supporting the containment spray/cooling subsystem, as defined in the TS, licensee personnel did not display a questioning attitude by revisiting the operability decision reached when the FOI was identified as a "lack of documentation."

- The inspectors noted that one of the changes made to the USAR described a revision to the computer code used for the containment analyses. In Revisions 2 through 12, USAR Table 5.2-7, assumption 12 stated "The May-Witt decay heat curve is used." The basis for this assumption stated "Accepted by NRC for Mark I containment evaluation." In Revision 13, this assumption was revised to state "The ANSI/ANS 5.1-1979 decay heat curve is used," and the basis was revised to state "SRP 6.2.1.3 & R.G. 1.157." The inspectors noted that, while RG 1.157 did state that ANSI/ANS 5.1 "is considered acceptable for calculating fission product decay heat," it also stated in the Introduction that "Any models, data, model evaluation procedures, and methods listed as acceptable in this regulatory guide are acceptable in a generic sense only and would still have to be justified to the NRC staff as being appropriately applied and applicable for particular plant operations." The safety evaluation did not address why the use of the new codes was acceptable on a plant specific basis and why the margin of safety previously included through use of a conservative decay heat model was not decreased through use of the more realistic code.

- The inspectors ascertained that bases for TS 3.5/4.5C reiterated that a subsystem consisted of two RHRSW pumps and two RHR pumps. It further noted that "Loss of one RHR service water pump does not seriously jeopardize the containment spray/cooling capability as two of the remaining three pumps can satisfy the cooling requirements." The safety evaluation did not address this TS bases or why the margin of safety described in the bases (i.e. two of three RHR service water pumps) was not decreased by the change to a one pump/one pump scenario.

- The inspectors also found that, although the safety evaluation addressed TS bases 3.7/4.7 in regard to the containment pressure, it did not address how

the following statement in the bases was satisfied: "For an initial maximum suppression chamber water temperature of 90°F and assuming the normal complement of containment cooling pumps (2 LPCI pumps and 2 containment cooling service water pumps) containment pressure is not required to maintain adequate net positive suction head (NPSH) for the core spray, LPCI and HPCI pumps. However, during an approximately one-day period starting a few hours after a loss-of-coolant accident, should one RHR loop be inoperable and should the containment pressure be reduced to atmospheric pressure through any means, adequate NPSH would not be available. Since an extremely degraded condition must exist, the period of vulnerability to this event is restricted by Specification 3.7.A.1.b by limiting the suppression pool initial temperature and the period of operation with one inoperable RHR loop."

As discussed in Section E1.1, the licensee had not performed a formal calculation to determine the NPSH required for the one pump - one pump scenario. However, the licensee's informal evaluation showed that containment overpressure was required to maintain adequate NPSH. The inspectors determined that changing the design basis condition to a one pump/on pump configuration increased the amount of time when containment overpressure was required to ensure adequate ECCS pump NPSH. Additionally, the inspectors determined that the change in design basis condition decreased the margin of safety described in the TS bases because "an extremely degraded condition" was being redefined as the plant design basis.

10 CFR 50.59 permits licensees to make changes in the facility as described in the safety analysis report, provided the change does not involve an unreviewed safety question. The regulation states that a proposed change shall be deemed to involve an unreviewed safety question (1) if the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report may be increased; (2) if a possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report may be created; or (3) if the margin of safety as defined in the basis for any TS is reduced. The inspectors determined that the licensee's change to the facility as described in Section 5.2.3 of the USAR appeared to involve an unreviewed safety question and was an apparent violation of 10 CFR 50.59 (50-263/96009-11(DRS)). This determination was relayed to the licensee during the inspection and at the exit interview on January 8, 1997. On January 23, 1997, the licensee submitted a license amendment requesting clarification of the TS bases and NRC review and approval of a change to the design accident containment temperature and pressure response.

c. Conclusions

The inspectors concluded that the change to the facility as described in Section 5.2.3 of the USAR appeared to involve an unreviewed safety question. As prior Commission review and approval of this change was not sought, an enforcement conference was scheduled with the licensee for March 5, 1997. The results of that conference will be documented in a later inspection report.

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Support of Maintenance

a. Inspection Scope

The inspectors reviewed selected WOs and discussed details with the RHR system engineer. Engineering support was also discussed with maintenance personnel.

b. Observations and Findings

The inspectors noted that several engineers were permanently assigned to the maintenance staff to provide engineering support; however, most engineering support for the RHR system was provided by the RHR system engineer. Discussions indicated that the system engineer was deeply involved in RHR maintenance activities. Licensee personnel stated that the system engineer personally wrote most of the work orders for the RHR system. They also stated that detailed instructions were not always required because of experienced maintenance personnel and the involvement of the system engineer in the maintenance activities.

c. Conclusions

The inspectors concluded that engineering support of RHR maintenance activities was very good with the system engineer deeply involved in RHR maintenance activities and the resolution of maintenance problems.

E2.2 Results of USAR Review

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the USAR that related to the areas inspected. The inspectors verified that the USAR wording was consistent with the observed plant practices, procedures, and parameters, except as discussed in Section E1.8 and below:

The inspectors identified the following discrepancy: USAR Section 6.2.3.2.3, Revision 14, "Containment Spray/Cooling," in describing the RHR system in the containment spray/cooling mode of operation, stated that the flow returns to the suppression pool via the full flow test line, and referred to Figure 6.2-6. The referenced figure showed the drywell and suppression pool spray mode of containment cooling, where the flow did not return via the full flow test line.

E3 Engineering Procedures and Documentation

E3.1 Review of RHR Heat Exchanger Efficiency Tests

a. Inspection Scope

The inspectors reviewed surveillance procedure 1136, "RHR Heat Exchanger Efficiency Tests," from 1992 through 1995. This included Revisions 12, 14, and 15.

b. Observations and Findings

Change in Heat Exchanger Area: In Revision 15, approved March 20, 1995, the licensee revised the heat exchanger effective area from the 4150 square feet, listed in the heat exchanger specification, to 3954 square feet. The inspectors questioned the engineer about how this new area was determined. In response, the licensee provided a copy of an NRC internal memorandum (C. E. Rossi to E. G. Greenman, "Heat Transfer Duties for BWR Perfex Heat Exchangers," January 15, 1993) as well as a memorandum from General Electric to the NRC. (R. C. Mitchell, GE, to C. E. Rossi, NRC "10 CFR Part 21 Evaluation RHR & Containment Cooling Heat Exchanger (Perfex)" December 17, 1992). These documents described a problem with the calculated heat exchanger duty, identified by the NRC at the Dresden Nuclear Station. The memorandum from GE identified that Monticello, along with two other sites, would experience a decrease in the heat exchanger duty. When Monticello received the information from GE, they erroneously concluded that the reduction was to the *effective heat transfer area*. Licensee personnel unofficially determined the new area and revised the surveillance procedure. Furthermore, the acceptance limit for the above surveillance was dependent upon the heat exchanger area. The surveillance required determining the overall heat transfer capability by dividing test results by the heat transfer area. This value was then compared to a design value, which was calculated based on the design basis heat exchanger area. In effect, the change to a heat exchanger area not supported by design documents artificially improved the heat exchanger heat transfer rate by approximately five percent. This was directly opposite to the condition that GE identified to the licensee.

10 CFR Part 50, Appendix B, Criterion XI, "Test Control" requires, in part, that written test procedures incorporate the requirements and acceptance limits contained in applicable design documents. The revision to surveillance 1136, to decrease the heat exchanger area to a value not contained in any design document, resulted in the correct acceptance limits no longer being incorporated into the test procedure. This is considered an example of a violation of Criterion XI (50-263/96009-12(DRS)).

The inspectors reviewed Dresden Inspection Report 50-237/249/92034 and determined that the issue described in the above memos involved the heat transfer capability of the heat exchanger following a design basis accident and assuming that only one RHR pump and one RHR service water pump were operating. (See Section E1.8 for more discussion of the one pump/ one pump issue.) In comparison, the inspectors noted that the licensee was using as their acceptance

limit what appeared to be a normal shutdown heat transfer case. During discussions regarding the above issues, licensee personnel stated that they were considering revising the acceptance limit to reflect the "K" value used in the GE analyses. During these discussions the licensee also mentioned that the heat exchangers were tested conservatively, due to the time of year when the testing occurred. The inspectors noted that the heat exchangers were tested at approximately the same time each year; however, the time chosen to do the testing was early spring when river temperatures were normally very low. This approach would be excellent if the licensee trended temperatures from one test to the next year, as it reduced the effect of temperature on the results. However, since the tests were compared to a standard design value, the better approach would be to obtain a log mean temperature difference as close as achievable to the design value. The inspectors noted that this could be done without duplicating the accident temperatures by choosing times when the river temperatures approached normal suppression pool temperatures.

Use of Computer Program "HX-PERF": In addition to changing the heat exchanger effective area, the inspectors also noted that the 1995 test used a computer program to calculate the heat exchanger capability. The inspectors reviewed portions of calculation CA-94-020, "RHR/RHR Service Water Heat Exchanger Performance," Revision 1, May 19, 1995. The inspectors noted that on page 2 of the calculation, under "Assumptions/Analysis," the following statement was made:

> "C/A 94-020 Rev 0 (page 33/54) assumed that, for the RHR Service Water, a millivolt signal of 10 mV corresponded to 0 GPM and 50 mV corresponded to 7000 GPM. Per the System Engineer, the following should be assumed:
>
> 1. For the "A" loop, 10 mV corresponds to 0 GPM, and 50 mV corresponds to 8000 GPM. The conversion equation becomes:
>   GPM=1264.9*SQRT(millivolt-10.0)
> 2. For the "B" loop, 4 mV corresponds to 0 GPM, and 20 mV corresponds to 8000 GPM. The conversion equation becomes:
>   GPM=2000.0*SQRT(millivolt-4.0)"

The inspectors noted that verification of the calculation consisted of confirming that, when the above equations were included as part of the computer program, the computer arrived at the same numerical result as the human verifier. The verification did not question, much less confirm, the fundamental changes being made to the program regarding the equations and the instrument ranges. In order to confirm that the assumptions were correct, the inspectors reviewed elementary diagram NX-7905-46-13, Revision 6, which showed the flow indicators for the RHR and RHR Service Water System, and the calibration procedures for the flow indicators. The inspectors also performed a field walkdown to verify that the "A" loop indicator was scaled from 0 to 50 millivolts while the "B" loop indicator was scaled from 4 to 20 millivolts. Finally, the inspectors independently determined that the above equations were correct. Based on this, the inspectors had no problems with the changes made to the program. However, the inspectors were

concerned about the quality of the verification performed on the revision, as confirming that a computer could perform mathematical operations did not appear adequate. This is considered another example of a violation of 10 CFR Part 50, Appendix B, Criterion III in that design control measures did not verify the adequacy of the calculation (50-263/96009-13(DRS)).

The inspector briefly reviewed the remainder of the calculation and verified several of the formulae used. However, given the complexity of the calculation and the extent of the verification performed on the revision, the inspectors questioned whether the original verification was adequate to ensure that the computer program arrived at the correct conclusion regarding the heat transfer capability of the heat exchangers. For example, the inspectors noted that various physical properties (specific volume, thermal conductivity, viscosity) were calculated from an equation derived from data in the steam tables for water at 50 psia. The inspectors were concerned whether adequate verification was performed of these derived equations. The inspectors also noted that the conversion of flow from gallons per minute (gpm) to pounds mass per hour (lbm/hr) appeared to have an error in that 3991 gpm equaled 1.996×10^6 lbm/hr but 4000 gpm only equaled 1.983×10^6 lbm/hr (instead of 2×10^6 lbm/hr).

The inspectors calculated the heat transfer coefficient for the 1995 test using the more conservative hand calculational method described in the procedure and determined that the heat exchangers met the acceptance limit contained in the test. Therefore, the inspectors had no concerns regarding the operability of the heat exchangers.

Timeliness and Adequacy of Review: In addition to the above technical concerns, the inspectors had a regulatory concern regarding the timeliness of the system engineering review of the 1995 test. The 1995 test was performed on March 23, 1995 and referenced Revision 0 of the HXPERF program. Although the shift engineer signed the test as complete on March 23, the RHR system engineer did not sign until August 15, 1996, and the RHRSW engineer did not sign off until November 14, 1996. Additionally, the inspectors noted that the attached HXPERF output sheets, as required by the procedure, were dated October 22, 1996. Given the nature of the change made between Revision 0 and Revision 1, the inspectors questioned which revision of the computer program was used. By converting the millivolt differential pressure signal to flow and comparing that to the computer results attached to the test, the inspectors confirmed that Revision 1 was used. Therefore the inspectors determined that the heat exchangers had been returned to service in March 1995 prior to determining that the heat exchanger acceptance limits were met. Additionally, the inspectors were concerned that the licensee did not write a condition report to identify that the procedure was unworkable as written, that an issued calculation contained a fundamental error, or that the heat exchangers were not verified to have met their test acceptance limits until 19 months after they were returned to service. This is considered another example of a violation of 10 CFR Part 50, Appendix B, Criterion XI, in that the test results were not evaluated prior to the equipment being returned to service (50-263/96009-14(DRS)).

c. Conclusions

The inspectors concluded that the design and test control limits exercised over surveillance 1136 were flawed in that the problems described above were not recognized and corrected. These issues appeared to be reflective of other test control problems discussed in Inspection Reports 50-263/96005, 96006 and 96008.

E3.2 Design Bases Document Reviews: Downgrade of Portions of RHR to Non-Safety Related

a. Inspection Scope

The inspection team reviewed the licensee's DBD B.3.4, "Residual Heat Removal System," Revision 2, to determine the functional requirements for the system and active components. These requirements were compared to applicable portions of the USAR and licensing basis commitments. It is important to note that the licensee did not consider the DBDs themselves to be documents within the Quality Assurance (QA) Program, because the DBDs only summarized previously documented design basis information. Therefore, the team did not consider inaccurate details within the DBDs to be relevant; however, broader design basis concepts were treated as being the licensee's established position.

b. Observations and Findings

The DBD noted that the containment (drywell and torus) spray mode and shutdown cooling mode of RHR operation were considered to be non-safety-related functions. The determination in the DBD appeared to conflict with the licensee's USAR and with statements made by the licensee in previous submittals to the NRC.

Regarding the **containment spray** mode of RHR, Revision 13 of USAR, Appendix E, Section E.2.7, "Engineered Safety Features," stated:

> The pressure suppression pool and the containment spray/cooling system provide two different means to rapidly condense the steam portion of the flow from the postulated design basis loss-of-coolant-accident so that the peak transient pressure shall be substantially less than the primary containment design pressure.

USAR, Section 5.2.3.3, "Containment Analysis Results," stated:

> One operator option is to align the RHR in the containment spray mode. This would quench the steam in the containment airspace and rapidly drop the temperature and pressure. It is conservative to neglect this option.

USAR, Section 6.2.3.3.2, "Containment Spray/Cooling," stated:

> The containment spray/cooling function can be performed with the RHR after the core is flooded. . . . Suppression pool water can then be diverted to either of two cooling modes:
>
> 1. Containment Spray Cooling. . .
> 2. Suppression Chamber Cooling. . .

The licensee's basis for containment spray being a non-safety-related function was that the containment response calculation did not take credit for containment sprays. In addition, the licensee cited NUREG-1433, and noted that drywell sprays were not included.

With respect to the **shutdown cooling** mode of RHR, NRC's "Safety Evaluation for Full Term License Review, Monticello Nuclear Plant, Unit 1," Supplement 1, dated December 1980, for Task A-31 "Residual Heat Removal Shutdown Requirements," stated, in part, that the licensee had committed to performing a detailed evaluation of their RHR shutdown capability in accordance with the guidelines established in draft Regulatory Guide 1.139. The licensee provided the results of this evaluation in a letter to NRC, dated June 24, 1981, which stated:

> Redundant safety grade systems meeting the requirements of General Design Criteria 1 through 5 are available to bring the plant to cold shutdown within 36 hours and maintain cold shutdown using either on-site or off-site power. Availability of redundant systems assures that a single failure cannot prevent achieving these conditions. . . . Two methods available to maintain cold shutdown are:
>
> 1. The RHR Shutdown Cooling System can accomplish this function by itself.
> 2. An alternate method is to circulate water between. . . .

The letter concluded by stating this "indicates that the guidelines of Regulatory Guide 1.139 can be satisfied."

In determining that the shutdown cooling function was non-safety-related, the licensee's DBD FOI 91-0293, Revision 1, stated, in part, that "NSP did not state and the [NRC] staff did not require, either explicitly or implicitly, that the equipment used for the RHR shutdown cooling mode of operation would be upgraded to a safety related designation." The FOI went on to make a distinction between a design basis event and a licensing basis event, and noted that "there was no clear causality between (non-accident) licensing basis event mitigation and safety related equipment." The FOI also recommended that the Q List Committee consider changing the designation of certain RHR equipment from a safety-related status based on the FOI's assessment.

The team acknowledged that the containment spray mode of RHR had not been specifically relied upon to mitigate the consequences of an accident; however, neglecting this operational mode was noted as being conservative. The team questioned the licensee's position that a system function was non-safety-related because it was not specifically used in an accident analysis, even though the

original design basis considered it a redundant function. In addition, although drywell sprays were not contained in the BWR/4 Standard TS, suppression pool sprays were included, but this inconsistency was not addressed by the licensee. Only the favorable portion of standard TS was cited.

In addition, the team was concerned because the DBD FOI for shutdown cooling appeared legalistic, did not focus on safety, and minimized the significance of previous commitments to the NRC. Since the safety-related status had not yet been changed within the QA Program, no regulatory action was warranted. However, the inspectors considered the trend toward downgrading safety-related equipment as an Inspection Followup Item (50-263/96009-15(DRS)) where the inspectors would seek further guidance from NRR.

Additionally, although the licensee did not consider the DBDs to be QA documents, the team identified one instance in a Power Rerate analysis where a DBD was referenced as the only source of a specific value. Engineering Evaluation 41.1, "Containment Inerting System," Revision 0, used the DBD for Primary Containment as the source of the suppression pool drawdown value. While this example was not considered significant, it illustrated a potential problem for misusing DBD information during the design process. As of the end of the inspection, the licensee had not written a condition report, or otherwise determined how to deal with this issue.

c. Conclusions

Although the piping, pumps and valves in the RHR system were still listed in the QA Plan for components subject to Appendix B of 10 CFR Part 50, at the time of the inspection, the team questioned the licensee's motives and bases for "changing" QA classifications in the non-QA DBD.

E3.3 Review of Electrical Design Basis Documents

a. Inspection Scope

The inspectors reviewed selected electrical DBDs, calculations and associated analyses, design assumptions, boundary conditions, and models with the electrical distribution system in general and particularly the RHR electrical components. The inspectors also examined functional requirements for the system and active components during accident and abnormal conditions.

b. Observations and Findings

The inspectors noted that the licensee had produced a number of DBDs including, for example, the RHR system, 125 Vdc power, 480 Vac power distribution and 4kV power distribution. Additionally, there were DBDs for specialized areas such as MOVs. These DBDs formed an archive for pertinent information including listings of related modifications, calculations and other design drawings, criteria and correspondence. Overall this appeared to be a solid initiative; but, as discussed above, the DBDs were not to be considered as source documents.

The calculations reviewed were the most recent updates of worst case scenarios for 125 Vdc station blackout (SBO) Load Profile Study (CA-91-012, Revision 2, dated December 27, 1993), 250 VDC SBO Load Profile (CA91-046, Revision 2, dated March 15, 1996, and Plant Voltage Study, 1R, LOCA Load, 2 CS Pumps Starting (CA91-069, Revision 4, dated February 27, 1995). These recent calculations appeared to have resolved some concerns, such as nonconservative and undocumented assumptions that developed during the EDSFI and during the licensee's independent review of electrical power distribution systems.

c. Conclusions

The inspectors determined that the design basis for the those areas examined was generally in accordance with the facility's licensing commitments and regulatory requirements. The inspectors concluded that these recent calculations appeared to be well documented, but because of the complexity and multiple variables it was difficult to determine if these worst bounding conditions contained only unchallengeable assumptions.

E3.4 Minor Drawing and Administration Problems Identified

During review of the RHR equipment environmental qualifications, the inspectors attempted, without success, to locate in the technical library the EQ Part B Environmental Specification files for various components. The licensee also could not locate the files in the technical library and then found they had been removed and discarded due to an inadvertent error by the clerical staff. The licensee prepared Condition Report 96002679 dated November 20, 1996. In addition, the inspectors identified minor drawing errors related to instrument numbers; these were provided to the system engineer. Discrepancies were also identified between control room, DBD, Operation Manual and surveillances regarding the names used for the instrument panels.

Additionally, the inspectors identified that the RHR DBD contradicted USAR Section 6.2.3 regarding bypassing the containment spray interlocks.

E7 Quality Assurance Activities in Engineering

E7.1 QA Status of Follow-on Items

Throughout the inspection, discussions were held with the licensee regarding the QA status of FOIs, especially in regard to the FOI being incorporated by reference into a safety evaluation. In an internal memo dated January 16, 1997, the licensee clarified the position of FOIs in regard to their long-term retrievability. The memo stated "FOI records are currently being handled and retained as QA records are required to be maintained, i.e., storage, checkout process, auditing, long term record retention, and retrievability." A Quality Services observation, 1997021, performed January 20, 1997, stated "The auditor verified the procedures SGP-02.07 and SGP-3.04 include requirements of ANSI N45.2.9 and concludes that FOIs are programmatically maintained as QA lifetime records." However, the inspectors noted that neither of these documents actually stated that FOIs were considered QA records.

E7.2 Review of Power Rerate Submittal

a. Inspection Scope

The inspectors performed a cursory review of the licensee's application for increasing the licensed power level to determine how some of the issues identified during the inspection were handled in the application.

b. Observations and Findings

Net Positive Suction Head Calculations: Due to the error contained in calculation CA-96-090, which appeared to result in an inadequate NPSH for the CS pumps during long term operation, the inspectors reviewed the submittal in regard to NPSH availability. The inspectors noted that the submittal stated that there was no decrease in NPSH margin between available and required NPSH for the ECCS pumps from current licensed power conditions to those at the proposed power level. The submittal further stated that this was due to the increase in containment pressure compensating for the increased head loss due to higher vapor pressures. The inspectors were concerned about the origin of these statements, as CA-96-090 clearly indicated a decrease in available NPSH, even assuming credit for containment overpressure.

During discussions with the licensee on this issue, the inspectors learned that the submittal statement was based upon a calculation performed by the NSSS vendor which compared the change in NPSH due to vapor pressure versus containment pressure, as these were the only variables in the NPSH calculation that the vendor considered would be affected by the change. The inspectors reviewed portions of the vendor calculation and agreed with the conclusions drawn from the calculations. However, the inspectors noted that the calculations provided to the inspectors as the governing NPSH calculations did not reflect the conclusions reached in the vendor's calculation and asked the licensee what steps were taken to resolve the discrepancies. In response, the licensee informed the inspectors that the calculation for the current licensed condition, EqDE-34-0687, was no longer valid, due to the change in pump configuration discussed in Section E1.8, and, therefore, should not be compared to CA-96-090. Because of the changes in assumptions between EqDE-34-0687 and CA-96-090, along with the errors in CA-96-090, the inspectors agreed that a direct comparison was not possible.

Following the exit, the licensee provided the inspectors with a copy of a Quality Services observation report, 1996420, "Monticello Rerate Project." The inspectors noted that the observation report, performed from November 5, 1996 through January 10, 1997, asked several probing questions about the rerate program. In item 12 of the observation report, the auditors observed "The Appendix R Evaluation, Task 17.2, evaluates containment response following the fire event. This evaluation includes an NPSH evaluation which states that the analysis shows that while maximum suppression pool bulk temperature is higher due to rerate, the containment pressures are also higher. The conclusion is that NPSH available during the Appendix R event is higher at rerate conditions, but this conclusion is not supported by calculation CA-96-090 for pDBA LOCA. Calculations should identify required NPSH at expected pump operating conditions and demonstrate NPSH

available at expected pool conditions. This may be significant, since the NPSH margin for the Core Spray pump for DBA LOCA long term is quite small, only 0.47 ft."

The response to the observation stated: "The arguments stated in the Appendix R evaluation, Task 17.2, are valid. GE has a calculation in their associated project file that *should* support this statement. NSP has not reviewed most GE calculations. The results of the evaluation do show that NPSH available gains from containment pressure increases more than offset NPSH vapor pressure losses from higher fluid temperatures. As part of the ECCS suction strainer modification project, a computer model that effectively evaluates the ECCS suction ring header and calculates NPSH available has be developed by Duke Engineering for Monticello. A rigorous determination of NPSH available for all the ECCS pumps is being made for various accident scenarios at current and Rerate conditions. MNGP licensing basis does use containment pressure in determining NPSH available."

Although the focus of the auditors' question was on the Appendix R event, the inspectors discerned that the auditors considered CA-96-090 as the governing NPSH calculation for rerate conditions. The inspectors acknowledged that the vendor had performed an analysis comparing current and rerate NPSH conditions due to vapor pressure and containment pressure changes; however, it appeared that the licensee could have done better in documenting what documents supported the conclusion in the submittal that NPSH margin was not affected. In addition, as discussed in Section E1.1, while the licensee considered that the Monticello licensing basis allowed use of containment overpressure, it was not clear how much credit the NRC had granted (i.e., if the licensee could increase the amount of credit taken without penalty), based upon the statement in the bases to TS 3.7/4.7 (see Section E1.8). The inspectors discussed these concerns with the cognizant individuals in NRR.

The licensee provided a discussion of the NPSH concern in a letter to the NRC dated January 20, 1997. In this letter, the licensee reiterated that the vendor's sensitivity study formed the basis for the statements in the submittal and noted that the purpose of CA-96-090 was "to provide confirmatory information that the ECCS pump NPSH available is greater than the ECCS pump NPSH required. . . ." The licensee further stated ". . .Specifically, if a comparison was made between the results from the Monticello confirmatory Power Rerate NPSH calculation and a 1987 core spray pump NPSH calculation for current licensed conditions, then a conclusion could be drawn that the proposed power level would have an adverse effect on ECCS pump NPSH. However, comparison of this information is not valid. These two sets of calculations were performed based on differing input assumptions; whereas, the GE analysis discussed in the power rerate submittal is based upon consistent methodology to assess the ECCS NPSH at the current licensed power and the proposed power rerate conditions." The inspectors did not disagree with the statements made by the licensee regarding the NPSH concerns.

Use of GOTHIC Computer Code: The inspectors were informed by licensee personnel that the GOTHIC computer code was used to support the power rerate HELB analyses. As discussed in Section E1.3, use of the GOTHIC code has not been approved by NRC. The licensee's position, as stated in the January 20, 1997,

letter is "Regarding failure of the Monticello Power Rerate submittal to identify the use of the GOTHIC computer code for the power rerate analysis of the effects of High Energy Line Breaks (HELBs), it is our understanding that the use of this computer code for this analysis is not specified in the regulations of the Commission nor in the conditions of the Monticello Facility Operating License as requiring NRC staff review or NRC staff approval prior to use. The GOTHIC computer code is an industry developed code. The computer code was developed under a quality assurance program which satisfies the criteria of 10 CFR 50, Appendix B. Prior to use of the GOTHIC program at the Monticello plant, a verification activity was performed to confirm that the GOTHIC computer code provided results consistent with the previous code used for this type of analysis. Monticello has used the GOTHIC computer code for the evaluation of temperature, pressure and humidity profiles following postulated High Energy Line Breaks."

The letter goes on to state: "It is not evident to the Monticello staff that the use of revised methods for this type of analysis is information material to NRC staff review of these issues. . . . The review of the Monticello Power Rerate submittal is ongoing. Should the NRC staff determine that additional information is material to their review, then Monticello recognizes the need to be responsive to the information needs of the staff and provide information as required to support the NRC staff review."

Since the NRC had reviewed the computer codes used during the original HELB analysis, the inspectors considered that staff would consider the use of a new computer code relevant to their review. Therefore, the inspectors informed the NRR staff of the licensee's use of the GOTHIC computer code in the rerate HELB analyses.

<u>On-going Rerate Tasks</u>: In addition to the above two concerns, the NRC inspectors were also informed, by the licensee, that there were several tasks related to the rerate project where all work was not complete. Two specific tasks were 1) confirmation of assumptions used in a vendor task report, and 2) impact of RHR motor efficiencies on the RHR room heatup analysis. In the January 20, 1997 letter, the licensee discussed these specific items and provided a list of other items which were on-going. The inspectors had been concerned that the reviewers were not aware that there were on-going tasks which had the potential, however small, to affect the review of the submittal; however, discussion in the January 20 letter resolved that concern.

c. <u>Conclusions</u>

The inspectors concluded that the inspection efforts provided information which would be useful for the NRR staff to be aware of during review of the licensee's power rerate submittal. The licensee provided additional information regarding these issues in a January 20, 1997 letter.

E8 Miscellaneous Engineering Issues

E8.1 <u>(Closed) Violation 50-263/96005-02</u>: Inadequate test controls on core spray motor testing. The inspectors reviewed the licensee's response to the violation. The

licensee committed to revising the administrative procedure for special tests to address offsite testing being performed to address onsite issues. The licensee also committed to provide training to the engineering staff regarding the requirements for written procedures and acceptance criteria. The inspectors observed that the actions taken would ensure that the particular violation of test controls would not recur. This item is closed.

E8.2 (Open) Unresolved Item 50-263/96005-03: Justification for use of SRI 95-002 to isolate cooling water to the core spray motors. As discussed in Section O4.1, the licensee had committed to reevaluating the test results prior to isolating cooling water to the core spray pump motors. As of the inspection, no official evaluation had been performed and SRI 95-002 had not been revised. This item remains open.

E8.3 (Closed) Unresolved Item 50-263/96005-04: The licensee reperformed the RHR room heatup calculation. The new calculation, CA-96-113, "Temperature of RHR Rooms During DBA LOCA," revised the input assumptions discussed in the unresolved items and determined that the maximum room temperature would be approximately 141°F. The inspectors only reviewed the input parameters, such as river temperature, service water flow to the coolers, and motor heat input. The inspectors concluded that the concerns raised in Inspection Report 96005 were resolved. This item is closed.

V. Management Meetings

X1 Exit Meeting Summary

On January 8, 1997, the inspectors presented the inspection results to the Plant Manager. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

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ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-263/96009-01	IFI	TS don't address electric power requirements during conditions other than power operation
50-263/96009-02	VIO	First example of Design Control: Calculation not controlled
50-263/96009-03	VIO	Second example of Design Control: Error in vapor pressure
50-263/96009-04	URI	Determination if any limit on credit for containment overpressure
50-263/96009-05	VIO	Third example of Design Control: nonverified & nonconservative assumptions
50-263/96009-06	URI	Determination on acceptability of use of GOTHIC computer code
50-263/96009-07	URI	Resolution of acceptability of MOV low voltage concerns
50-263/96009-08	URI	Resolution of 80 percent voltage starting analysis on RHR motors
50-263/96009-09	VIO	First example of 50.59: Cancelled modification
50-263/96009-10	VIO	Second example of 50.59: Multiple USAR changes
50-263/96009-11	EEI	Apparent violation of 50.59 involving a USQ
50-263/96009-12	VIO	First example of Test Control: Incorrect area added to surveillance
50-263/96009-13	VIO	Fourth example of Design Control: Inadequate verification of changes to calculation
50-263/96009-14	VIO	Second example of Test Control: Procedure signed off before acceptance criteria verified incorrect version of program used
50-263/96009-15	IFI	Down-grading of RHR subsystems to non-safety related

Closed

50-263/96005-02	VIO	Failure to have valid test procedure for offsite test
50-263/96005-04	URI	Non-conservative assumptions in RHR room heatup calculation

Discussed

50-263-96-05-03	URI	Conclusions of SRI 95-002 on cooling to core spray pump motors

LIST OF ACRONYMS USED

ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CR	Condition Report
CS	Core Spray
DBD	Design Basis Document
DC	Design Change
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Item (Apparent Violation)
EPRI	Electric Power Research Institute
EOP	Emergency Operating Procedure
EQ	Environmental Qualification
FOI	Follow-On Item
GDC	General Design Criteria
GE	General Electric
GL	Generic Letter
GOTHIC	Generation of Thermal-Hydraulic Information for Containments (computer code)
GPM	Gallons per Minute
HELB	High Energy Line Break
HP	Horsepower
HPCI	High Pressure Coolant Injaction
IFI	Inspection Followup Item
IST	Inservice Testing
LBM/HR	Pounds Mass per Hour
LPCI	Low Pressure Coolant Injection
MOV	Motor-Operated Valve
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSP	Northern States Power
OC	Operations Committee
PSIG	Pounds per Square Inch (Gauge)
QA	Quality Assurance
RELAP	Reactor Excursion and Leak Analysis Program (computer code)
RG	Regulatory Guide
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
SER	Safety Evaluation Report
SRI	Safety Review Item
TS	Technical Specification
TSI	Technical Specification Interpretation
URI	Unresolved Item
USAR	Updated Safety Analysis Report
USQ	Unreviewed Safety Question
VIO	Violation
WO	Work Order
WRA	Work Request Authorizations

PROCEDURES USED AND DOCUMENTS REVIEWED

NRC Documents Used or Reviewed During the Inspection

CORRESPONDENCE

Ltr dtd 7/29/74 K. R. Goller, AEC, to Northern States Power (NSP), Report on Postulated Pipe Failures Outside Containment

Ltr dtd 6/3/81 T. A. Iappolito, NRC, to L. O. Mayer, NSP, "Environmental Qualification of Safety- Related Electrical Equipment"

Ltr dtd 6/13/90 W. O. Long, NRC, to T. M. Parker, NSP, Correction of Original Nonconforming High Energy Line Break Conditions and Closure of TAC 61788

Ltr dtd 7/13/93 A. Thadani, NRC, to G. L. Sozzi, General Electric (GE), "Use of SHEX Computer Program and ANSI/ANS 5.1- 1979 Decay Heat Source Term for Containment Long- Term Pressure and Temperature Analysis"

Ltr dtd 2/8/96 D. M. Crutchfield, NRC, to G. L. Sozzi, GE, "Staff Position Concerning General Electric Boiling Water Reactor Extended Power Uprate Program (TAC M91680)"

Ltr 12/13/96 T. J. Kim to NSP, "Meeting with NSP to Discuss the Contents of the License Amendment Request Supporting the Monticello Extended Power Uprate Program"

Memo dtd 2/15/91 C. Monteith, NSP, to W. Long, NRC, "Monticello Station Blackout Submittal Questions/Answers," (Attached)

Memo dtd 12/17/92 R. C. Mitchell, GE to C. E. Rossi, NRC, "10 CFR Part 21 Evaluation, RHR & Containment Cooling Heat Exchangers (Perfex)" (Attached)

Memo dtd 1/15/93 C. E. Rossi, NRC, to E. G. Greenman, NRC, "Heat Transfer Duties for BWR Perfex Heat Exchangers" (Attached)

INSPECTION PROCEDURE

IP 93801 Safety System Functional Inspection, Rev 2

INSPECTION REPORTS

50-237/93024	NRC Special Inspection of the Dresden Nuclear Station (EA 93-019), 4/20/93
50-249/93024	Notice of Violation and Proposed Imposition of Civil Penalty, 7/15/93 Response to Notice of Violation, 9/3/93
50-263/94004	NRC Routine Inspection Report and Notice of Violation, 7/5/94 Response to Notice of Violation, 8/5/94
50-263/96005	NRC Integrated Inspection Report and Notice of Violation, 7/23/96 Response to Notice of Violation, 8/22/96

GENERIC COMMUNICATIONS

IE Bulletin 79- 01B	Environmental Qualification of Safety Related Electrical Equipment
Generic Letter 83-11	Licensee Qualification for Performing Safety Analysis in support of Licensing Activities
NUREG 0588	Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment
NUREG-1433	Standard Technical Specifications, General Electric Plant, BWR/4
Reg. Guide 1.1	Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps
Reg. Guide 1.157	Best Estimate Calculations of Emergency Core Cooling System Performance

SAFETY EVALUATION REPORTS

Safety Evaluation by the Division of US Atomic Energy Commission in the Matter of NSP MNGP Unit 1, Docket 50-263, 3/18/70

Safety Evaluation by the US Atomic Energy Commission for NSP MNGP Unit No 1, Full Term Operating License, 2/5/73

Safety Evaluation for Full Term License Review Monticello Nuclear Plant Unit 1, Supplement 1, 12/80

Issuance of Amendment 22 to the Facility Operating License, including Safety Evaluation, 2/2/84

Issuance of Amendment 27 to the Facility Operating License, including Safety Evaluation, 10/31/84

Safety Evaluation of GE Topical Report NEDC-31336 "Instrumentation Setpoint Methodology," 2/9/93

Licensee Documents Reviewed During the Inspection

The following is a list of licensee documents reviewed during the inspection, including documents performed by others on the behalf of the licensee. Inclusion in this list does not imply that the NRC reviewed and accepted the documents in their entirety, but, rather that portions of the documents were evaluated as part of the overall inspection effort.

CALCULATIONS

CA-90-018	Determination of Acceptance Criteria for RHR Pump Surv Testing
CA-91-012	125VDC DBA Load Profile/Battery Sizing
CA-91-046	250 VDC SBO Load Study Profile
CA-91-069	Plant Voltage Study, 1RHR, LOCA Load, 2 CS pumps
CA-91-099	Load Study Operating Motor and Load Database, Rev 6

CA-92-036	RHR Pump Room Temperature Analysis
CA-92-214	RHR System Motor-operated Valve Functional Analysis, Rev 6
CA-92-221	RHR System MOV Performance Analysis, Rev 3
CA-92-224	Emergency Diesel Generator Loading, Rev 2
CA-93-056	Suppression Pool Drawdown Calculation, Rev 0
CA-94-075	Acceptability of As-found Condition on RHR Support TWH-173, Rev 0
CA-94-106	Determination of Drywell High Pressure Instrument Setpoints
CA-94-020	RHR/RHRSW Heat Exchanger Performance, Rev 2
CA-95-005	Low Low Water Level ECCS Initiation
CA-95-006	Instrument Setpoint Calculation, ECCS Low Pressure Pump Start Permissive, PS-2-3-53A/B, Rev 0
CA-95-007	Instrument Setpoint Calculation ECCS Low Pressure Valves Permissive PS-2-3-52A, Revs 1 & 2
CA-95-008	Instrument Setpoint Calculation, ECCS Low Pressure Valve Permissive, PS-2-3-52B
CA-95-022	Instrument Setpoint Calculations, RHR APR Interlock, PS-10-105E/F/G/H
CA-95-021	Instrument Setpoint Calculation, RHR APR Interlock, PS-10-105A/B/C/D
CA-95-028	Instrument Setpoint Calculation, Reactor High Pressure Shutdown Cooling Isolation, PS-2-128A/B
CA-95-073	Reactor Low Water Level Scram Setpoint
CA-95-089	RHR Suction Path Head Loss, Rev 0
CA-96-090	Evaluation of ECCS Net Positive Suction Head, Rev 0
CA-96-113	Temperature of RHR Rooms During DBA LOCA, Rev 0
CA-96-166	Drywell Flooding Evaluation for Post DBA LOCA
DRF T23-00731	Monticello Power Rerate - Revised NPSH Calculations. (Proprietary) 4/16/96
EQ Central File	Part B, "Environmental Specifications," Rev 4, 9/13/91
GE-NE-T2300731-1	Containment Response Evaluation Task 6.0, GE (Proprietary), 4/96
EqDE-34-0687	Monticello Nuclear Plant Core Spray System Operational Capability Report, GE Calculation, 7/87 (draft revision attached)
MN.9309.005-02	Evaluation of Anchors and Penetrations on RHR Discharge Loop A for Removal of Snubber SS-561, Rev 0
NEDC-32513	Suppression Pool Cooling and Water Hammer, GE
NEDO- 30485	Monticello Design Basis Accident Containment Pressure and Temperature Response for FSAR Update, GE, 12/83
NEDO- 32418	Monticello Design Basis Accident Containment Pressure and Temperature Response for USAR Update, GE, 12/94
NSE14-0481	RHR Evaluations for HPCI Failure or RHR Shutdown Cooling Failure, GE, 4/81
V609.000.00001	Low Pressure Emergency Core Cooling System (ECCS) Net Positive Suction Head, Vectra, 1/97
0091.19601.035. 00100	Evaluation of Supports SR-625 & SR-626, Duke Engineering & Services, 1/97
01-0910-1137	Monticello Nuclear Generating Plant Environmental Effects Due to Pipe Rupture, Impell, Revs 0 (12/80) & 3(10/86)
091-19407-C-3	GOTHIC Verification, Vectra, Rev 0, 12/21/94
0910-111-392	Postulated Pipe Failure Outside Containment, Bechtel, 08/73

CORRESPONDENCE

From NSP to the US AEC/NRC

Responses to AEC Questions on Monticello High Energy Line Breaks Outside of Containment, 3/20/74
Resolution of Task A-31 RHR Shutdown Requirements, 10/15/80
Response to IE Bulletin 79- 01B, 10/31/80
Revised Schedule for Resolution of A-31 RHR Shutdown Requirements, 4/9/81
Resolution of Task A-31 RHR Shutdown Requirements, 5/12/81
Resolution of Task A-31 RHR Shutdown Requirements, 6/24/81
License Amendment Request - RHR Intertie Line Addition, 5/29/84
License Amendment Request - Containment Leakage Testing Technical Specifications, 5/1/86
Response to Generic Letter 96-01 "Testing of Safety-Related Logic Circuits", 4/17/96
License Amendment Request - Supporting the Monticello Nuclear Generating Plant Power Rerate Program, 7/26/96
Information Concerning Potential Violation of 10 CFR 50.9(a), 1/20/97

From Vendor/Contractor to NSP

Supports SR- 625 and SR- 626, from Duke Engineering & Service, 12/18/96
Response to NSP Comments on Containment Response Evaluation (Task 6.0), from GE, 4/18/96
Ltr dtd 12/17/96 D. C. Pappone, GE, to S. J. Hammer, NSP

Internal Memoranda

QA Record Classification of Follow-On-Items and Design Basis Documents, 1/16/97
Containment Long-Term Cooling Response - SSOPI Issue, 12/30/96

DESIGN BASIS DOCUMENTS (Proprietary Documents)

B.3.4 Residual Heat Removal System, Rev 2, 11/5/96
B.4.1 Primary Containment, Rev A
T.4 Environmental Qualification (EQ), Rev A, 12/17/93
T.6 High Energy Line Break Topics. Rev 0, 1/15/93
T.8 Internal Flooding, Rev 1, 5/25/95
T.13 Regulatory Guide 1.97, Rev A, 1/25/95

DESIGN CHANGES AND ALTERATIONS

Alterations

94A005	ITT Barton 288/289A Part # Cross Reference
94A008	Insulator Materials for Egs Quick Disconnect (QDC) Electrical Connector
94A014	RHRSW CV-1729 and CV-1729 Parts Change

94A028	Rosemount Transmitter Model Number Change for CGCS Gas Flow and Pressure
94A029	Barton Model 580 Series Lens Replacement
94A052	ECCS Valve Upgrades
94A033	RHR Motor Replacement

Design Changes

85M042	RHR System Pressure Upgrade Modification
89Z021	Effective Loss of 125 VDC on ECCS
92Q735	Rotork Replacement Modification
93Q200	RHR Motor Replacement

DRAWINGS

Electrical Schematics and Single-line Drawings

NE-36404-4	ACB-152-504	11 RHR motor, Rev V
NE-36404-4A	ACB-152-604	12 RHR motor, Rev AA
NE-36404-4B	ACB-152-503	13 RHR motor
NE-36404-4C	ACB-152-603	14 RHR motor, Rev Z
NX-7823-4	729E856	Elementary Diagram Primary Containment Isolation System, Sheets 6-10
NX-7826-2	718E971 PL	Fuel Pool Cooling and Cleanup, Sheets 1-4
NX-7831-1	718E965 PL	Nuclear Boiler
NX-7831-6	718E987 PL	Nuclear Boiler Vessel Instrumentation, Sheets 1-5
NX-7831-23	729E203	Functional Control Diagram, Recirculation Flow Control System, Sheets 1-3
NX-7831-58	730E834	Functional Control Diagram, Nuclear Boiler System, Sheets 1-2
NX-7905-1	729E194	Residual Heat Removal, Sheet 1
NX-7905-2	729E194 PL	Residual Heat Removal, Sheets 1-8
NX-7905-4	729E510	Process Diagram, Residual Heat Removal System, Sheet 1
NX-7905-6	729E587	Functional Control Diagrams, RHR System, Sheets 1-3
NX-7905-46	730E287	Elementary Diagrams, Residual Heat Removal System, Sheets 1-20

Isometrics for the RHR System Piping

NF-36372	Piping below 935', Rev M
NF-36504	Piping below 962', Rev G
NF-36505	Piping below 985', Rev J
NF-36506	Piping below 1001', Rev C
NF-36507	Piping below 1027'
NF-36513	Piping below 948', Rev L
NF-74551	A DW Injection & SDC Line, Rev G
NF-74552	B RHR Return Loop, Rev G
NF-97027	A Intertie Line, Rev A

NL-96841-2	RHR Pump Discharge, Rev A
NL-96842-1	RHR Pump Discharge, Rev A
NX-13142-17	Loop Line Drawing, Rev E
NX-13142-18	Loop Line Drawing, Rev L
NX-13142-20	A Head Spray Isometric, Rev H
NX-13142-31	A Minimum Flow Line Drawing, Rev J
NX-13142-37	A LPCI & Containment Spray Drawing
NX-13142-37-1	RHR/Drywell Cont Spray, X-39B Loop A, Rev A
NX-13142-49	A SDC Suction Drawing, Rev K
NX-13142-51	B Minimum Flow Line Drawing, Rev L
NX-13142-62	A Fuel Pool Connection, Rev A
NX-13142-67	Reactor Water RHR Isometric,Rev D

<u>P&IDs</u>

M-112	NH-36664	Residual Heat Removal Service Water and Emergency Water Service Systems, Rev AY
M-115	NH-36241	Nuclear Boiler, Rev AQ
M-116	NH-36242	Nuclear Boiler Vessel Instrumentation, Rev AP
M-117	NH-36243	Recirculation Loops, Rev AK
M-120	NH-36246	Residual Heat Removal System, Sheet 1, Rev BB
M-121	NH-36247	Residual Heat Removal System, Sheet 2, Rev BB
M-135	NH-36256	Fuel Pool Cooling System, Rev Z
M-811	NH-36665	Service Water System and Make-up Intake Structure, Rev BP

<u>EQUIPMENT DRAWINGS</u>

NX-7833-5	RHR Pump Motor (12, 14, and Spare RHR Motors) Outline Drawing, Rev B
NX-7905-73	11 RHR Pump Motor Outline Drawing
NX-7905-74	13 RHR Pump Motor Outline Drawing, Rev B
NX-7905-11	AO-10-46a,b Cross-Sectional, Rev C
NX-8291-6	Vent Insert Assembly, Rev 1
NX-8291-16	Drywell Vent Jet Deflectors, Rev 2
NX-8291-24	Vent Pipe Header Intersection, Rev A
NX-8291-34	Suppression Chamber Vent Header Assembly, Rev E
NX-9231-2	2006,2007 Cross-Sectional, Rev E
NX-9231-3	RHR-9 Cross-Sectional,Rev F
NX-9231-5	2008,2009 Wiring Diagram, Rev C
NX-9231-12	2008,2009 Cross-Sectional, Rev G
NX-9231-17	2032,2407 Cross-Sectional, Rev E
NX-9231-20	RHR 1-1,1-2,1-3,1-4 Cross-Sectionals
NX-9231-21	RHR 1-1,1-2,1-3,1-4 Cross-Sectionals
NX-9231-24	RHR 4-1,4-2,5-1,5-2, 7 Cross-sectionals, Rev B
NX-9231-22	2010,2011 Cross-Sectional, Rev C
NX-9231-27	2033 Cross-Sectional, Rev B
NX-9231-35	RHR 8-1,8-2 Cross-Sectionals

NX-9231-37-2	2002,2003 Cross-Sectional
NX-9231-41	1988,1989 Cross-Sectional, Rev C
NX-9235	Valve Cross-Sectionals
NX-9548-10	1986,1987 Cross-Sectional, Rev A
NX-16836-1	Flow Element 4113-Reactor Feedpump Seal Supply and FE-10-121A-D RHR System
NX-16921-1	RHRSW Motor Cooling Water Safety and Relief Valves (Farris Relief Valves RV-2025, RV-1991, RV-1992, RV-1993 and RV-1994)
NX-21345-1	RHR 6-1,6-2 Cross-Sectionals, Rev C
NX-21345-2	4085,4086 with Actuator, Rev D
NX-32433	2407 with Actuator

EQUIPMENT SPECIFICATIONS

21A0100	GE Electric Motor Design Specification, Rev 0
21A1045	GE General Requirement Specification for Testable Check Valves, Rev 0
21A1045AD	GE RHR Testable Check Valve Specification Data Sheet, Rev 1
21A1036	GE Standard Requirements for RHR Heat Exchanger, Rev 0
221A1036AB	GE RHR Heat Exchanger Purchase Specifications Data Sheets, Rev 4
21A1272AC	GE Flow Element Purchase Specification Data Sheets, Revs 0 & 1
21A1272AX	GE Flow Element Purchase Specification Data Sheets, Rev 1
21A5790	GE General Requirements of RHR Pump, Rev 0
21A5813	GE RHR Pump, Purchase Specifications - Data Sheet, Rev 7
257HA423	GE Residual Heat Removal System Design Specifications, Rev 0
257HA423AE	GE Residual Heat Removal System Data Sheet Design Specification, Rev 5
5828-E-27	Bechtel Specification Valve Motor Operators, Rev 3
5828-M-53	Bechtel Purchase Order/Requisition Nuclear Cast Carbon Steel Valves
5828-M-54	Bechtel Specification, Nuclear Cast Carbon Steel Valves
5828-M-57	Bechtel Specification, Nuclear Cast Carbon Steel Valves

FOLLOW ON ITEMS

91-0295	RHR Bypass Valve Accumulator Tank Sizing
92-0032	RHR System Design/Analysis Inconsistency
92-0064	Reduced Voltage Effects on Motor Starting
92-0153	Revised NPSH Calculation (DRF T23-00731), 12/8/96
94-0012	Pipe Breaks at RHR, CS and SBLC Containment Penetrations, 2/15/94

MISCELLANEOUS

CHAMPS listing of RHR Component ID's vs Component Description
Chart Recorder FLR-6-96 dated April 10/11, 1996
Computer Master List printouts for the following instrumentation:
FI-7189, FI-7188, LIS-2-3-672A/B/C/D, LT-2-3-72 A/B, PS-2-3-53A/B, PS-2-3-52A/B, PS-2-128A/B, PS-10-101A/B/C/D, PS-10-105A/B/C/D/E/F/G/H
Computer Printouts for River Water Temperatures for years 1993 thru 1995
Maintenance Performance Indicators

OPERATING EXPERIENCE ASSESSMENTS

MSCP 21-95-003	Perfex Heat Exchanger Containment Cooling, Part 21 Notice (GE)
MSCP 21-95-004	Unanalyzed Water Hammer Loads, Part 21 Notification from General Electric (SC95-01)
SIL 375	Power Supply for Discharge Line Fill System on BWR 4/5/6 ECCS and RCIC System

PREOPERATIONAL TESTS

01-17-70	Pre Operational Test Procedure A-8 Residual Heat Removal
08-22-70	RHR Pre-op Test Report
09-10-70	Residual Heat Removal Pre-op A-8 - Amendment II
09-10-70	Pre-operational Test Procedure A-8 Residual Heat Removal
06-30-72	Summary Report for Pre-operational Tests and Startup Test Results

PROCEDURES

Administrative Procedures

4AWI-01.01.01	Administrative Controls Program, Rev 4
4AWI-04.05.01	General Work Controls, Rev 10
4AWI-04.05.02	Requesting Work and Work Order preparation, Rev 11
4AWI-04.05.03	WO Review, Rev 10
4AWI-04.05.04	Conduct of Maintenance, Alterations and Design Changes, Rev 8
4AWI-04.05.05	WO Closeout and Disposition, Rev 7
4AWI-05.06.01	Safety Review Item, Rev 4
4AWI-06.01.05	Alterations Process, Rev 5
4AWI-09.04.01	Inservice Testing Program Implementation, Rev 4
N1AWI-05.1.12	Plant Design Change Review Package Preparation, Review and Approval Form 3629, Rev 5
EWI-09.04.01	Inservice Testing Program, Rev 3
MWI-3.M.2.01	AC Electrical Load Study

Design Basis Document Support Procedures

SGP-02	Design Basis Document Procedures
SGP-02.01	Preparation of Design Basis Documents
SGP-02.02	Evaluation of Source Documents in Generating Design Basis Documents
SGP-02.03	System Design Basis Documents Writers Guide
SGP-02.04	Topic Design Basis Documents Writers Guide
SGP-02.06	Structure Design Basis Documents Writers Guide
SGP-02.07	Identification, Validation, Tracking, and Evaluation of Configuration Management Follow-on Items and Resulting Corrective Actions
SGP-02.08	Design Basis Document Verification
SGP-02.09	System Information Document Writers Guide

Design Procedures

MOV-00	MOV Introduction, References, and Definitions, Rev 0
MOV-01	MOV Program Document
MOV-02	MOV Engineering Standards
NAP1.001A	Policy and Procedure Directive, Rev 15
NAP3.006T	Monticello Methodology Change, Rev 2

Emergency Operating Procedure Flowcharts (Proprietary)

C.5-1100 Rev 4, C.5-1200 Rev 5, C.5-1205 Rev 2, C.5-1300 Rev 4, C.5-1400 Rev 4, C.5-2003 Rev 5, C.5-2004 Rev 5, C.5-2006 Rev 5, C.5-2007 Rev 7, C.5-3403 Rev 0

Maintenance Procedures

4018PM	Spare ECCS Motors (Electrical Inspection), Rev 7
4019PM	Spare ECCS Motors (Mechanical Inspection), Rev 4
4044OCD	RHR Loop A Leak Rate Test, Rev 5
4045OCD	RHR Loop B Leak Rate Test, Rev 5
4180PM	RHR Pump, Rev 2
4181-1PM	11 RHR Pump Motor, Rev 3
4181-2PM	12 RHR Pump Motor, Rev 4
4181-3PM	13 RHR Pump Motor, Rev 4
4181-4PM	14 RHR Pump Motor, Rev 4
4181-1OCD	11 RHR Pump Motor, Rev 1
4181-2OCD	12 RHR Pump Motor, Rev 1
4181-3OCD	13 RHR Pump Motor, Rev 1
4181-4OCD	14 RHR Pump Motor, Rev 1
4182PM	RHR System, Rev 6
4229-2OCD	RHR-2-2 AND RHR-2-4 Pump Discharge Check Valves, Rev 0
4229-2PM	RHR B Pump Discharge Check Valve, Rev 0
4821-1PM	RHR System A Electrical Maintenance, Rev 1
4821-2PM	RHR System B Electrical Maintenance, Rev 1
4821-1OCD	RHR System A Electrical Maintenance, Rev 3
4821-2OCD	RHR System B Electrical Maintenance, Rev 2
4862PM	Shutdown Cooling Isol Valve Electrical Maintenance, Rev 2
4862OC	Shutdown Cooling Isol Valve Electrical Maintenance, Rev 1
4863PM	Head Spray Valve Electrical Maintenance, Rev 1
4863OCD	Head Spray Valve Electrical Maintenance, Rev 1
4906PM	Air Supply Check Valves, Rev 2
4916-11OCD	Lubrication; SW & SE Rx Bldg Equipment Rooms, Rev 2
4916-11PM	Lubrication; SW & SE Rx Bldg Equipment Rooms, Rev 8
4916-20PM	Lubrication - Miscellaneous, Rev 9
4920-4OCD	Replacement of SV-1994 (11 RHR Pump Minimum Flow), Rev 2
4920-5OCD	Replacement of SV-1995 (12 RHR Pump Minimum Flow), Rev 2
4920-6OCD	Replacement of SV-1996 (13 RHR Pump Minimum Flow), Rev 2
4920-7OCD	Replacement of SV-1997 (14 RHR Pump Minimum Flow)
7110	RHR System Instrument Maintenance Procedure, Rev 13

Operations Manual

B.3.4	Residual Heat Removal System
B.3.4-01	Function and General Description of RHR System, Rev 1, 4/11/89
B.3.4-02	Description of Equipment (RHR System), Rev 8, 10/29/96
B.3.4-03	Instrumentation and Controls (RHR System), Rev 5, 10/18/94
B.3.4-04	References (RHR System), Rev 7, 11/7/96
B.3.4-05	System Operation (RHR System), Rev 10, 11/14/96
B.3.4-05.D	Startup Procedures
	Shutdown Cooling Mode - Loop A
	Shutdown Cooling Mode - Loop B
	Torus Cooling Mode
B.3.4-05.E	Operating Procedures
B.3.4-05.F	Shutdown Procedures
	Shutdown Cooling Mode
	Torus Cooling Mode
B.3.4-05.G	Special Procedures
	Venting RHR System Discharge Piping - Normal Operation
	Venting RHR System Discharge Piping-With S/D Cooling in Service
	RHR to Radwaste - Normal Mode
	RHR to Radwaste Mode with Shutdown Cooling in Service
	Emergency Fuel Pool Cooling
	RHR System Flushing
B.3.4-05.H	Abnormal Procedures
	Placing Torus Cooling in Service After a LPCI Initiation
	RHR Service Condensate Pressurizing Station(s) Out of Service
	RHR Heat Exchanger Tube Leak
B.3.4-06	Figures (RHR System), Rev 1, 10/6/92
B.4.1	Primary Containment
	Section 02.01, Revision 4
	Section 03, Revision 2
C.4-b.3.4.A	Loss of Normal Shutdown Cooling
C-4.D	Shutdown Using Emergency Systems

RHR System Response Procedures

C.6-003-A-03	RHR I/II Discharge Shutdown Headers on High Pressure, Rev 3
C.6-003-a-04	Containment Spray Pump Manual Override, Rev 3
C.6-003-a-05	Containment Spray Flow Low, Rev 2
C.6-003-a-10	RHR Hx A Tube/shell Low Differential Pressure, Rev 4
C.6-003-a-11	RHR Hx A or B High Cooling Water Temperature, Rev 3
C.6-003-a-12	RHR Hx A or B Discharge Water High Temperature, Rev 3
C.6-003-a-18	RHR Water A High Conductivity, Rev 2
C.6-003-a-19	RHR Pump 11 High Seal Leakage, Rev 2
C.6-003-a-20	RHR Pump 13 High Seal Leakage, Rev 2
C.6-003-a-25	Auto Blowdown Timer Activated, Rev 0
C.6-003-a-26	RHR I Valves Motor Overload (OL), Rev 2
C.6-003-a-34	RHR I Injection Valves Motor OL, Rev 2
C.6-003-a-41	AC Interlock, Rev 2
C.6-003-a-42	RHR Pump 11 Lockout, Rev 2

C.6-003-a-43	RHR Pump 13 Lockout, Rev 2
C.6-003-a-50	RHR Pump 11 OL/Manual Override, Rev 3
C.6-003-a-51	RHR Pump 13 OL/Manual Override, Rev 3
C.6-003-a-56	RHR Pmp 11/13 No Suction Auto Trip, Rev 2
C.6-003-b-01	RHR Pmp 12/14 No Suction Auto Trip, Rev 2
C.6-003-b-04	RHR Pump 12 Lockout, Rev 2
C.6-003-b-06	RHR Test, Rev 2
C.6-003-b-12	RHR Pump 12 OL/Manual Override, Rev 3
C.6-003-b-19	RHR Hx B Tube/Shell Low Differential Pressure, Rev 4
C.6-003-b-20	RHR Pump 12 High Seal Leakage, Rev 1
C.6-003-b-27	RHR Water B High Conductivity, Rev 2
C.6-003-b-28	RHR Pump 14 Lockout, Rev 2
C.6-003-b-35	RHR II Valves Motor OL, Rev 2
C.6-003-b-36	RHR Pump 14 OL/Manual Override, Rev 3
C.6-003-b-43	RHR II Injection Valves Motor OL, Rev 2
C.6-003-b-44	RHR Pump 14 High Seal Leakage, Rev 2
C.6-003-b-45	RHR High Reactor Pressure, Rev 2
C.6-003-b-50	RHR Logic Bus Monitor, Rev 2
C.6-003-b-54	Containment Spray Permissive, Rev 1
C.6-003-b-56	High Area Temperature Steam Leak, Rev 2

Surveillance Procedures

0103	LPCI System Simulated Auto Actuation
0104	Drywell Spray Headers and Nozzles Air Test, Rev 1
0255-04-IA-1	RHR Pump and Valve Tests, Revs 39 & 40 (completed tests dated 12/20/95, 3/21/96, 5/10/96, 6 22/96 & 9/21/96)
0255-04-IA-2	RHR System Cold Shutdown Valve Operability Test, Rev 12
0255-04-IA-3	RHR Valve Position Indication Check, Rev 6
0255-04-IA-4	RHR Loop A Minimum Flow Check Valve RHR-8-1 Operability Test, Rev 3
0255-04-IA-4OCD	RHR Loop A Minimum Flow Line Check Valve Operability Test, Rev 1
0255-04-IA-5	RHR Loop B Minimum Flow Line Check Valve RHR-8-2 Operability Test, Rev 3
0255-04-IA-5OCD	RHR Loop B Minimum Flow Line Check Valve Operability Test, Rev 0
0255-04-IB-1	A RHR System Relief Valve Set Point and Leak Checks, Rev 16
0255-04-IB-2	B RHR System Relief Valve Set Point and Leak Checks, Rev 16
0255-04-IIAOCD	RHR Pressure Test, Shutdown Cooling Suction
0255-04-IIB-1	RHR Loop A Functional Test
0255-04-IIB-2	RHR System Pressure Test Loop B Functional Test
0255-04-IIB-3	RHR Shutdown Cooling Suction Functional Test, Rev 0
0302	Safeguard Bus Degraded Voltage Protection-Relay Unit Calibration, Rev 12
0391	Shutdown Cooling Supply Isolation Interlock Instrument Test, Rev 3
0392	Shutdown Cooling Supply - Isolation Interlock Instrument Calibration Procedure (See 0391), Rev 3
0419-6	ASDS RHR Torus Cooling, RHR Service Water and Emergency Service Water Functional Test, Rev 4

1136	RHR Heat Exchanger Efficiency Test, Revs 11, 12, 14 & 15 (completed tests dated 4/16/92, 5/17/93, 3/16/94 & 3/23/95)
1202-1	RHR Loop A System Leakage Test, Rev 3
1202-2	System Leakage Check Procedure B RHR System, Rev 8
1339	ECCS Pump Motor Cooling Flush
1376	RHR and Core Spray Pump Motors Oil Sampling, Rev 1
1381	RHR System Cross-tie Flow Verification, Rev 39
2120	Plant Prestart Checklist - RHR System
2154-12	RHR System Prestart Valve Checklist
8018	Procedure for RHR Heat Exchanger Inspection
8018-1 & 2OCD	RHR Heat Exchanger
8192	RHR Intertie Flush, Rev 0
8716	Special Procedure for Testing 12 RHR Hx Leak Tightness, Rev 0
8772	Special Procedure for Freeze Sealing RHR Pump 11 Minimum Flow Line, Rev 0
8776	Determine RHR System Pipeline Assistance Curve, Rev 0
8781	Obtain Data to Check Calibration of RHR Flow Nozzles FE-10-110B and FE-10-108B, Rev 0
8815	Procedure for Draining the Reactor, Rev 0
8842	RHR System Layup, Rev 0
8872	Shutdown Cooling from Outside the Control Room

PUMP CURVES

NX-7905-51 Rev A	Pump Curve Pump No. 270427
NX-7905-52 Rev A	Pump Statistics Pump No. 270427
NX-7905-53 Rev A	Pump Curve Pump No. 270428
NX-7905-54 Rev A	Pump Statistics Pump No. 270428
NX-7905-55 Rev A	Pump Curve Pump No. 270429
NX-7905-56 Rev A	Pump Statistics Pump No. 270429
NX-7905-57	Induction Motor Speed Torque Current Curves - 600 Hp Motors
NX-7905-58 Rev A	Pump Statistics Pump No. 270430
NX-7905-59 Rev A	Pump Curve Pump No. 270430

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AG 94-16-10	Monticello Maintenance Work Control Audit Report
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AG 95-22-13	Monticello Inservice Testing (IST) Audit Report
OR-1996162	Monticello Isolation and Restoration Process Observation Report
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OR-1997021	Review of FOI Record Storage

SR-MO-94-036	Shutdown Cooling Supply #0391 Surveillance Report
SR-MO-94-084	RHR Service Water System Surveillance Report
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94000089	Contrary to Procedure, with the A RHR Loop in SDC Mode, the RHR to Radwaste Valves, 2032 & 2407, Were Opened
94000115	#12 RHR Pump Breaker, 152-604, Would Not Rack In
94000123	Flow Indicator FI-10-139A, RHR Loop A Injection Flow, Did Not Meet 1% Acceptance Criteria for as Left Settings
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94000137	MO-2032 Torque Switch Failure
94000209	Equipment Misalignment during RHR Intertie Line Flushing Using Special Procedure 8192
94000312	During VOTES Testing of 2023, and After the Valve Had New Rotork Installed, the Valve Opened into the Backseat
94001549	Shutdown Cooling Started with Torus Valve Open
95000132	DPIS 10-92B RHR Hx Tube/Shell DP Alarm out of Tolerance
95000135	No Receipt Inspection of RHR Motor
95001213	RHR Pump #11 SW Inlet Valve SW-110-1 Handwheel off
96000110	During RHR Instrument PM 7070, DPIS-1954 Was Found out of "As Found" Low (3.35 AF vs. 3.5 psi Lower Acceptance Limit)
96000003	Sandy Grit Found on Valve Stem of MO-2009
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96001020	DPIS 2-129B & D Mounting Hardware Installation
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96001053	Testing of RHRSW Aux Compressors K-10a & B Using Questionable Gauges
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96001628	RHR #14 Pump Seal Failure
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2019(3/14/96) - 2046(9/12/96) with exception of 2022 and 2043

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Meeting #96-01(4/24/96)- 96- 03 (10/14/96)

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NX-7905-32	RHR Heat Exchanger Instruction Manual
NX-7905-37	RHR Testable Check Valve Technical Manual
NX-7905-62	GEK 9534 Residual Heat Removal Instruction Manual
NX-7905-63	GEK 27823 Residual Heat Removal System Maintenance Instructions
NX-17066	Velan Forged Steel Manual Gate, Globe & Check Valves Technical Manual
NX-17099	13 RHR Pump Motor Technical Manual

NX-17151	Valtek Control Valves RHR-69-1, RHR-69-2 Technical Manual
NX-17066	Velan Forged Steel Manual Gate, Globe & Check Valves Technical Manual

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9490254	Replace Actuator on MO-2021
9490257	Perform Wiring Change & Replace Heater Element
9490300	Swap Motor Feeder Cables Between MO-2003 & MO-2009
9490364	Preoperational Test of MO-2003 & MO-2009
9403382	Rmv #11 RHR Pump Motor & Install Spare Motor
9403988	Setup & Perform VOTES DP test on MO-2002
9404031	Perform PM's 4900-2, VOTES on MO-2002
9404037	Perform PM's 4900-2. VOTES on MO-2010
9404381	Replace Bonnet Gasket/Clean/Refurbish & Measure AO-10-46B
9405265	Adjust Packing on MO-2014, RHR A Outboard Inj
9405277	Adjust Packing MO-2020 A RHR Otbd DW Spray Isol
9405294	Repack MO-2020 RHR A Outboard DW Spray
9405417	Remove/Reinstall Actuator, Disassemble/Reassemble, Inspect, Valve MO-2023
9405483	Remove Limit Switch Cover and Inspect/Tighten/Lock
9405484	Clean Line from A RHR Heat Exchanger Drain Trough
9405486	Replace Limit Microswitch for MO-2008 "A" RHR Torus
9405504	Investigate/Repair MO-2032 (RHR Discharge to Waste)-Valve Failed
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9500146	Perform Pressure Test on Cooling Coil & Evaluate, Pump 13
9500128	Inspect/Repair/Replace Switches & Mounting Screws RHR MO- 2032
9501023	Leaky Valve Stem on MO- 1986
9501089	Repair Isolation Valve for PS-10-118
9501338	Perform PM 4900-2 on MO- 1986
9501339	Perform PM 4900-2 on MO- 1987
9501340	Perform PM 4900-2 on MO- 1988
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9501342	Perform PM 4900-2 on MO- 2002
9501343	Perform PM 4900-2 on MO- 2003
9501344	Perform PM 4900-2 on MO- 2008
9501345	Perform PM 4900-2 on MO- 2010
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9501349	Perform PM 4900-1 on MO- 2013
9501350	Perform PM 4900-1 on MO- 2014
9501351	Perform PM 4900-1 on MO- 2015
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9501353	Perform PM 4900-2 on MO- 2010 on MO- 2021
9501354	Perform PM 4900-2 on MO- 2022
9501355	Perform PM 4900-2 on MO- 20232
9501357	Check DC voltage and AC ripple on RHR Div I PS
9501550	#13 RHR Motor Lower Bearing Drainplug Stripped

9501770	Remove Add-on-pack on MO-2032
9501796	Move Auxiliary Contacts on MO-2029
9501800	Move Auxiliary Contacts on MO-2030
9501806	Perform 4900-2PM on MO-2032 & Inspect Switches
9501812	Inspect Motor Pinion Key and Perform 4900-IPM on MO- 2029
9501813	Inspect/Secure Motor Pinion and Perform 4900-IPM on MO- 2030
9501814	Perform 4900-IPM on MO- 2407
9501915	Torque Mounting Bolts, Perform 4900-IPM on MO- 2006
9501916	Torque Mounting Bolts and Perform 4900-IPM on MO- 2007
9501932	Disassemble/Inspect MO-2009
9501935	Perform 4900-2PM on MO- 2022
9501937	Perform 4900-IPM (Parts A, B, C, and G)on MO- 2026
9501938	Perform 4900-IPM (Parts A, B, C, and G)on MO- 2027
9501941	Perform 4900-2PM on MO- 2033
9501961	Perform 4900-IPM (Parts A, B, C, and G) on MO- 4086
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9502116	Perform 4900-IPM (Parts A, B, C, and G) on MO- 4085A
950[illegible]81	Perform 4900-IPM (Parts A, B, C, and G) on MO- 4085B
9600063	Valve MO-2009 Stem Cleaning
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9600089	Replace bonnet on AO-10-46B
9600222	Adjust RHRSW Drain Length, Train A
9600223	Adjust RHRSW Drain Length, Train B
9600232	Dis-assemble, Drill Disc & Assemble MO-2007
9600244	Change Oil on MO-2021
9600752	Drilling Anti-locking Hole in Disc of MO-2006
9600753	Drilling Anti-locking Hole in Disc of MO-2007
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9600874	Perform Preoperational Test of MO-2007
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9601184	Inspect/Replace Motor on MO- 2014
9601186	Slight Packing Leak on MO- 1986
9601372	Replace Seal on #14 RHR Pump
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9601425	Inspect and Repair #14 RHR pump
9601662	Tighten Packing on MO-2027
9601665	Packing Leaking on Inboard Head Spray Valve
9602142	Investigate/Repair Small Oil Leak on MO- 2026
9602291	Perform Performance Monitoring on P-202A Prior to On-line Maintenance
9602406	Want Accurate V, I, and PF Data for ECCS Pump Motors
9602657	Measure RHR/CS/RHRSW Motor Speed
9602717	Reinstall Actuator Prot Stem Cap on RHR LPCI Otbd, MO-2012

5.2.8

INTEROFFICE MEMORANDUM

Date: 15-Feb-1991 05:01pm CST
From: Curt Monteith
MONTEITHC
Dept: Nuclear Projects Dept
Tel No: (612) 295-1654

TO: See Below

Subject: MONTICELLO STATION BLACKOUT SUBMITTAL QUESTIONS/ANSWERS

In response to, "NRC Questions RE: Monticello Station Blackout Submittal", from W. Long (NRR) to T. Parker (NSP) dated December 19, 1990, we offer the following answers to questions #6 & #7:

6. Analyses used to calculate steady state temperatures of the control room and drywell during SBO have been completed. These analyses conclude that the control room and drywell will reach temperatures that are below the maximum allowed temperature for components in the respective areas.

   The control room was assumed to have 10 occupants at 250 BTU/hr per occupant. A value of 11kW was calculated for electrical loads which included heat generated from cables, equipment and instruments. This value was derived from loads on the batteries and inverters. Battery loads were calculated by identifying all cables that carry load from the batteries to the control room and using load data known for each control room panel. Cables were assumed to be #14 AWG at a length of 250 feet one way. Actual cables are larger than #14 AWG and cable lengths are less than 250 feet. Using these figures yields conservative values for $I^2 \times R$ heat losses. Inverter loads were calculated by identifying the control room circuits from each inverter, and, using known inverter loading data. An emergency lighting load of 440 watts was also included. This load was based on the number of emergency lights located in the control room. As a conservative measure, a value of 15kW was assumed for all electrical loads. An average temperature for adjacent rooms was assumed to be 100.8°F. Adjacent rooms include administration rooms, reactor building, turbine building, HVAC room, and cable spreading room. The control room is assumed to have an initial temperature of 75°F. The duration of SBO is four (4) hours. The control room was modeled as a room volume with no HVAC operating. Building material thickness was assumed to be an average of 1.58 feet. The analysis used Bechtel "Room Heat Up" computer program ME-204 Version/Release A2-2 and concludes that after four hours of SBO the control room will reach a temperature of 109.7°F which is below the maximum temperature (120°F) allowed by NUMARC 87-00.

   The drywell temperature rise was calculated using the "Modular Accident Analysis Program" (MAAP) developed as part of the

JAN 28 1997

Industry Degraded Core Rule-making (IDCOR) program. MAAP used a subroutine to model the reactor vessel as a time dependent heat source. This model of the reactor vessel is based on the ANSI decay heat curve which, for Monticello, starts at ~2,500,000 BTU/hr and after 1½ hr decays to an average of ~2,200,000 BTU/hr for the remainder of the SBO. MAAP simulated the recirculation pump and technical specification allowed leakage as a small break LOCA whose leak rate corresponded to a value of greater than 165 gpm. MAAP modeled the following components in the drywell as heat sinks: the concrete, equipment, and steel containment. MAAP also accounted for the cooling effect of steam condensation on the drywell wall. The drywell temperature was found to be approximately 270°F which is less than the temperature rating (350°F) of equipment required to operate during SBO, as determined by NUMARC 87-00 Appendix F methodology.

7. The following containment isolation valves do not fall into the exclusion criteria given in NUMARC 87-00 or RG 1.155. To establish appropriate containment integrity, the valves must be closed. All valves identified can be manually operated by handwheels:

NUMBER	SYSTEM	PENETRATION	LOCATION
MO-1754	CS	X-16A	RWCU RM
MO-1753	CS	X-16B	962′ E, Mezzanine
MO-2023	RHR	X-39A	RWCU Rm
MO-2022	RHR	X-39B	935′ E, 950
MO-2011	RHR	X-211A	Torus Catwalk, Az 065
MO-2010	RHR	X-211B	Torus Catwalk, Az 295
MO-2015	RHR	X-13A	W S/D Cooling Rm
MO-2014	RHR	X-13B	E S/D Cooling Rm

All of the above valves have handwheels and would be manually closed by operators. Ladders are required to access valves MO-2014 and MO-2015. This access has been reviewed by operations and it is felt that access via ladders is adequate. All of the remaining valves identified above can be easily accessed by operators. No special precautions or equipment must be utilized to access or operate any of the valves. Assurance that the above valves have closed is obtained by visual inspection, verified by use of the handwheels.

The following is a clarification to Monticello Nuclear Generating Plant's Station Blackout Submittals to the Nuclear Regulatory Commission.

Clarification:

On page 1 of 2, March 29, 1990 Submittal

Replace the following statement:

"The hottest heat source in the torus room is the High Pressure Coolant Injection/Reactor Core Isolation Cooling System steam piping with a temperature of 160°F on the surface of the insulation."

With:

"The largest heat source in the torus room is the suppression pool. The torus room reaches a maximum temperature of approximately 146°F at the end of the SBO. This value does not include the effects of the heat contribution of the HPCI/RCIC piping due to the relatively insignificant amount of piping compared to the size of the suppression pool. This value also does not inclue the cooling effect of the concrete floor and walls of the torus room and the energy absorption of the mass of steel of the torus itself."

If you have any questions or comments, please call.

Very truly yours,

Curtis G. Monteith

Distribution:

TO: William Long	(LONGW)
CC: Byron Day	(DAY)
CC: Steve Engelke	(ENGELKE)
CC: Dale Larsen	(LARSEND)
CC: Dave Olson	(OLSOND)
CC: Keith K. Sunahara	(SUNAHARA)
CC: Terry Pickens	(PICKENST)
CC: Terry Coss	(COSST)

TECHNICAL SERVICES
Safety & Communications
San Jose, California

MEMO OF TELEPHONE CALL

DATE:	Thursday, December 17, 1992
TIME:	11:00 am pst
TO:	CE Rossi US Nuclear Regulatory Commission Fax (301) 504-2260
FROM:	RC Mitchell
SUBJECT:	10CFR PART 21 EVALUATION RHR & CONTAINMENT COOLING HEAT EXCHANGER (PERFEX)

Per your telephone request of 12-17-92, this memo is written to summarize the subject 10CFR Part 21 evaluation.

BACKGROUND

During GE's verification of the heat transfer capability of the Dresden 2 & 3 containment cooling heat exchangers, it was discovered that the heat exchanger was not capable of removing the design duty specified in the process flow diagram for one mode of operation. A GE-NE 10CFR Part 21 analysis was requested.

To resolve the discrepancies between the GE calculated heat exchanger capability and those identified in the process diagram and the Perfex specification, GE contacted the current manufacturer, Senior Engineering (previously Perfex). GE requested and obtained from Senior Engineering a new heat exchanger thermal performance calculation which agreed closely with the GE calculation

It was concluded that this concern was potentially generic to plants with Perfex heat exchangers and that all calculations for the Perfex designed Containment Cooling and Residual Heat Removal (RHR) system heat exchangers could have resulted in overstated heat transfer capabilities. All of these heat exchangers perform a safety related function and insufficient heat transfer capability could result in failure of the heat exchangers to successfully perform their required safety functions.

SAFETY BASIS

For the purpose of the 10CFR Part 21 evaluation, only the conditions pertaining to containment cooling were evaluated because these were the only safety-related conditions affected by the heat exchanger discrepancy. The results of the evaluation concluded that the discrepancy in the heat exchanger heat removal capability would not result in the failure of the heat exchangers to perform their required safety function. This conclusion was possible because the original heat load was based on the May-Witt model for decay heat. The more realistic ANS 5.1 decay heat model was used for this evaluation in conjunction with other conservative assumptions. This resulted in a heat exchange load which is 15% less than the May-Witt model which more than compensates for the 9% reduction in heat removal capacity for Dresden. The ANS 5.1 model has been previously referenced on other applications to the NRC and approved for those applications.

To address the other potentially affected BWR plants, GE requested that Senior Engineering perform a new set of heat exchanger performance calculations to verify the accuracy of the data contained in the Perfex heat exchanger specification sheets for these plants. The results of these calculations showed that for some of the plants, the heat transfer capability was within the originally specified Btu/hr duty and no discrepancy exists. However, for six other plants it was not within this specification. For these latter plants, GE calculated the degree of deficiency in the heat transfer capability using the results of the new calculations utilizing ANS 5.1. The newly calculated heat removal capability showed a 5.7 to 7.3% reduction for these other six plants (Containment spray mode). Thus, the heat removal capability of the heat exchangers remains greater than the heat input into the suppression pool.

GE-NE concluded that all Perfex RHR and Containment Cooling heat exchangers have sufficient capacity to handle the heat transfer duties required for containment cooling and that it was not a reportable condition. Each of the other six plants (Monticello, Peach Bottom 2 & 3, and Browns Ferry 1, 2 & 3) have been notified of this reduction in calculated heat exchanger capability. They were advised that GE-NE evaluated their plant(s) to be capable of removing the heat load based on the ANS 5.1 decay heat model and that they should take this into account for their past and future evaluations.

G0223011

MSCP21
93-001

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

January 15, 1993

MEMORANDUM FOR: Edward G. Greenman, Director
Division of Reactor Projects
Region III

FROM: Charles E. Rossi, Director
Division of Reactor Inspection
and Licensee Performance
Office of Nuclear Reactor Regulation

SUBJECT: HEAT TRANSFER DUTIES FOR BWR PERFEX HEAT EXCHANGERS

This is in response to your memorandum of December 16, 1992, identifying a potentially generic problem with BWR heat exchangers manufactured by Perfex (now Senior Engineering). We have contacted Pat Hiland and other members of your staff to discuss the issue. We are in the process of determining the potential safety significance of this item. If we determine that the issue requires prompt followup we will inspect GE on an expedited schedule. If the issue appears to be of minor safety significance we will include this item in the scope of our next scheduled vendor inspection at GE Nuclear Energy (GENE), currently scheduled for late Spring 1993.

With respect to your comment concerning the availability of names of potentially affected facilities, GENE has provided us with this information in the enclosed memorandum summarizing their Part 21 evaluation. The six additional facilities are Monticello, Peach Bottom 2 and 3, and Brown Ferry 1, 2 and 3.

Thank you for bringing this item to our attention.

Charles E. Rossi

Charles E. Rossi, Director
Division of Reactor Inspection
and Licensee Performance
Office of Nuclear Reactor Regulation

Enclosure:
As stated

cc: J. W. Roe, NRR
S. A. Varga, NRR
A. Gibson, Region II
A. W. Hodges, Region I
H. Miller, Region III
J. E. Dyer, NRR
B. L. Siegel, NRR
W. G. Rogers, SRI, Dresden
S. D. Burgess, Region III

1/3

EQE-74-0687
July 1987
DRF E21-63-4

Evaluation of Core Spray NPSH
at peak torus temp
of 184°F
See pencil calc.
AW
3-14-96

Conclusion -
NPSHA > NPSHR
Verified by
PAT
3-14-96

ENGINEERING SERVICES

MONTICELLO NUCLEAR PLANT

CORE SPRAY SYSTEM

OPERATIONAL CAPABILITY REPORT

PREPARED BY R. T. Reich DATE 8/3/87
R. T. REICH
PLANT SYSTEMS DESIGN

VERIFIED BY D.F. Casey DATE 8/3/87
D. F. CASEY
PLANT SYSTEMS DESIGN

REVIEWED BY R.W. Howard
R.W. HOWARD FOR R.S. VIJ DATE 8/3/87
R. S. VIJ, MANAGER
PLANT SYSTEMS DESIGN

APPROVED BY Ram S. Vij for DATE 8/3/87
J. JACOBSON, MANAGER
EQUIPMENT DESIGN ENG.

GENERAL ELECTRIC COMPANY
NUCLEAR FUELS AND ENGINEERING SERVICES DEPARTMENT
SAN JOSE, CALIFORNIA 95125

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ABSTRACT

A study was performed to: (1) determine the value of core spray pump discharge pressure, which is required to deliver design flow to the reactor during a Loss-of-Coolant Accident (LOCA); and (2) determine the adequacy of Net Positive Suction Head (NPSH) available to the Core Spray System pumps during a postulated LOCA event.

By analysis of the piping system and piping system losses during a LOCA event, required core spray pump surveillance test discharge pressure is 273.6 psig at rated core spray flow.

Adequate Net Positive Suction Head (NPSH) is available for the expected post-LOCA operation of the core spray pumps both short term and long term.

TABLE OF CONTENTS

I. SCOPE

This report covers two areas of interest with regard to Core Spray System at Monticello.

(1) The minimum value of pump discharge pressure which will demonstrate compliance with rated core spray pump performance.

(2) The Net Positive Suction Head (NPSH) available to the Core Spray pumps during the post-LOCA period, using design basis conditions. These are compared with the requirements of the Core Spray pump.

II. DESCRIPTION

The Core Spray System is made up of two independent loops with a single 3600 rpm motor driven pump in each loop. In the event of a Loss-of-Coolant Accident (LOCA), these two loops are called upon to pump water from the suppression pool into the core region of the reactor vessel. When the pressure inside of the reactor is 130 psi greater than the drywell pressure, each loop is required to pump 3020 gpm of water into the reactor core via spargers above the fuel bundles.

As part of the Emergency Core Cooling System, the Core Spray System is tested periodically to determine its capability to perform its emergency function.

The suction system is required to supply adequate Net Positive Suction Head (NPSH) during any proposed transient so that the Core Spray Pump can perform its short term core reflooding function as well as its long term core cooling function.

III. SUMMARY AND CONCLUSIONS

Design basis calculations demonstrate that the suction system design at Monticello should deliver sufficient Net Positive Suction Head (NPSH) to the Core Spray Pumps so that the requirements of the pumps are satisfied during the long term post-LOCA period.

If a design basis loss-of-coolant accident should occur, the core spray pumps will be operating at runout flow prior to the time (LOCA + 10 minutes) when credit can be taken for operator action to throttle core spray flow. By taking only 50% credit for suppression pool airspace pressurization but 100% credit for pool water heatup, adequate NPSH is shown to exist up to the point when pump throttling occurs. These assumptions are considered to be conservative.

IV. DISCUSSION

During a recent evaluation of the Core Spray System by members of the NRC Staff, some concern was raised over the adequacy of the pump suction system design. General Electric was asked to respond to this concern by Northern States Power (NSP).

A separate request from NSP was to determine the value of pump discharge pressure which would demonstrate satisfactory pump operation during required periodic surveillance tests.

A. Mechanical Design

The core spray system along with the residual heat removal (RHR), and the High Pressure Coolant Injection (HPCI) systems, take suction from the suppression pool via an intermediate ring header.

(The HPCI system normal water source is the condensate tank). The 20-inch diameter ring header is connected to the suppression pool torus at 4 points, all equally spaced around the torus. Each connection has a screened intake inside of the torus and is tied into the 20-inch ring header. Each cross-connection also has a 20-inch outside diameter (see Attachment 1).

Each two RHR pumps share a common connection to the ring header. The suction connection of the core spray pump in the same quadrant of the reactor building is connected to the ring header such that the suction intake for both systems straddle one strainer intake, and are equidistant from it. If a dividing line were drawn, the result would be a mirror image; i.e., the RHR intakes would be adjacent and the core spray intakes would be farthest from the dividing line.

B. System Design

A major point of emergency core cooling system design is that all post-LOCA Core Cooling system responses must allow for any one suction strainer plugged (Reference 2). The affect of the plugged strainer will be maximized when total flow is maximized. A pump or power failure may create a situation where in the flow from an individual RHR pump may be greater, but the affect in the ring header is to decrease overall flow.

1. Maximum Flow Case

The greatest overall flow will occur after a design-basis Loss of Coolant accident when all core cooling pumps are operating and the post-LOCA time is too short (< 10 minutes) to allow for operator control of systems flow. At this time, the reactor pressure, the drywell pressure, and the

IV. DISCUSSION (continued)

suppression pool air space pressure are all equal (Ref. 4), and the motor-driven pumps are operating at runout flow to the vessel. (HPCI is isolated on low reactor pressure.)

a.) RHR System Maximum Flow to the Reactor (Short Term)

The RHR system flow for this case is shown in the RHR System Data Sheet, 257HA423AE (Reference 1), as 15150 gallons/minute for 4 pump flow. This operation is not shown on the RHR Process Diagram, 729E570 (Reference 2).

b.) Core Spray Maximum Flow to the Reactor (Short Term)

The maximum core spray system flow to the reactor was calculated using the vendor, pump curve and the system resistance obtained during pre-operational testing. Per Attachment 2, Section A, core spray runout flow is about 4600 gallons per minute.

c.) Basis of Calculation of Net Positive Suction Head Available (NPSHA)

There are many scenarios which can be assumed in order to evaluate NPSH available. For these calculations, 50% of the suppression pool pressure presented in USAR Figure 5.2-[illegible] 15 (Reference [illegible], Rev 13) and 100% of the suppression pool water temperature presented in USAR Figure 5.2-17 (Reference 3) were used. On this basis, pool temperature is ~~137~~°F 143.6 and pool ambient pressure is 8.2/2 = 4.1 psig. 8.24

These assumptions were considered to be conservative for the purpose of NPSH calculations.

The near strainer of one set of RHR and core spray pumps is assumed to be plugged. The NPSH calculations are for the core spray pump nearest the plugged strainer, forcing the RHR and core spray suction flow to come from the more distant strainer. The longer flow path increases the suction friction losses and is therefore conservative.

d.) NPSH Available (Maximum Flow Case)

Calculations show (Attachment 2, Part A) that under the foregoing assumptions, the available Net Positive Suction Head is 34.8 feet whereas the pump requirement (Reference 5) is indicated to be 32 feet.

The point chosen to evaluate NPSH available was immediately prior to the time (over 10 minutes) when credit can be taken for operator actions which would result in decreased Core Spray Pump flow. The long term case (over 10 minutes) will be evaluated next.

2. Long Term Case 1 - Maximum Pool Temperature

During this period the operator has realigned the RHR system into the suppression pool cooling mode, and only 1 RHR and 1 core spray pump are operating. The flows for both systems are controlled by the operator.

a.) RHR Flow

The peak pool temperature will occur when only one RHR pump is available to cool the suppression pool. This is shown as Mode C2 on the RHR System process diagram (Reference 2). Per Reference 2, this flow is 4000 gallons/minute.

IV. DISCUSSION (continued)

b.) Core Spray Flow

The Core Spray Flow rate is regulated by the operator to rated flow of 3310 gpm as shown in condition IV of the core spray process diagram (Reference 6).

c.) Basis of Calculation of Net Positive Suction Head Available (NPSHA)

The basis of calculation of NPSHA for the long-term was established by SAR figure 5.2-17 which shows a pool water temperature of 179°F, a pool ambient pressure of 8.0 psig, and a flow rate of 3310 gpm. These conditions are conservative! Pool maximum temperature is shown by Reference 3 to occur at about 20,000 seconds (5.6 hrs) post-LOCA. At this same point, the suppression pool pressure is indicated by SAR figure 5.2-15 to be about 16 psig, not 8.0 psig used in the calculation. The near strainer is assumed to be plugged.

d.) NPSH Available (Long-Term Case 1)

The calculations show (Attachment 2, Part B) that under the foregoing assumptions, the available Net Positive Suction Head is 41.8 feet when ambient pool pressure is 8.0. This condition provides adequate NPSH for the Core Spray Pumps which require only 29 feet.

In addition, the condition of high pool temperature decreases with time due to continued operation of the RHR system in containment cooling as well as decreasing core decay heat with time. Therefore, if this period is ok, available NPSH should increase with time.

3. NPSH Available (Long-Term Case 2)

This case is similar to the previous case except that by definition in the RHR system process diagram (Reference 2) mode C1, two RHR pumps and the core spray pump in one quadrant are operating. The flows for both systems are controlled by the operator. This case is not part of the SAR because it is not a worst case for containment pressurization.

a.) RHR Flow

Per Reference 2, total RHR flow is 8000 gpm; 4000 gpm for each of two pumps. The two pumps share a common connection to the ring header. This connection and the suction connection for the operating core spray pump are equidistant from the nearest suction strainer connection to the ring header.

b.) Core Spray Flow

As in the previous case, core spray flow has been regulated by the operator to 3310 gpm (suction flow rate). This is the same flow rate as shown in Condition IV of the core spray process diagram (Reference 6).

c.) Basis of Calculation of Net Positive Suction Head Available (NPSHA)

Mode C1 of the RHR process diagram (Reference 3) indicates a suppression pool water temperature of 165°F and an ambient pool pressure of 17.8 psia. The adjacent strainer is assumed to be plugged.

IV. DISCUSSION (continued)

d.) NPSH Available (Long Term, Case 2)

The calculations show (Attachment 2, Part D) that under the conditions stated, the available Net Positive Suction Head for the core spray pump is greater than 35 feet; whereas 29 feet is required.

NPSH is clearly adequate under these conditions.

As in the previous case, the condition of high pool temperatures decreases with time due to continued containment cooling as well as decreasing core decay heat with time. Available NPSH should increase with time.

C. Adequate Core Spray Test Pressure

Calculations show (Attachment 2, Part C) that for surveillance tests, an indicated pump discharge pressure of 273.6 psig at the present gage location is adequate when the measured flow is 3020 gpm. This pressure represents an operating condition of 3020 gpm to the reactor when the pressure difference between the drywell and the reactor is 130 psi.

The value of 273.6 psig represents both and elevation difference of 13.25 feet plus a friction drop of 7.7 feet between the pump discharge location and the location of the instrument tap. Pump discharge pressure under this condition would be 28?.7 psig.

ATTACHMENTS

1. Ring Header Drawing, CB&I #215.R5

2. Calculations

   Section A   NPSH - Short Term Runout

   Section B   NPSH - Long Term, Case 1

   Section C   Surveillance Pump Discharge Pressure

   Section D   NPSH - Long Term, Case 2

   Section E   Evaluation of Minimum Flow

REFERENCES

Note: All references are included in this report for readers convenience.

1. RHR Design Specification Data Sheet, 257HA423AE,R.5; Sheet 5

2. RHR Process Diagram, [illegible]29E510,R.3

3. FSAR Figure 5.2-17, Pool Temperature Response vs Time

4. FSAR Figure 5.2-15, Pool Pressure Response vs Time

5. Bingham Pump Curve #26604, (VPF 2299-15-1)

6. Core Spray Process Diagram 161F301,R.2

ATTACHMENTS

MARK	QTY	DESCRIPTION			SPEC.
15-A		20" HEADER SECTION			
15-1	8	PL. 128 [illegible] X [illegible] KSK. (62 X 10-[illegible]) [illegible]	5	[illegible]	[illegible]
15-2	4	PL. [illegible] X [illegible] ([illegible]) [illegible]	5	[illegible]	CO.
15-3	4	PL. 19 [illegible] X [illegible] KSK. ([illegible] X 1'-7[illegible]) [illegible]	5	0 [illegible]	CO
5-X-204		20" PENETRATION			
15-6	4	INSERT PL. 32 O.D. X 1½ X 20[illegible] I.D. [illegible]			CO
15-7	4	WEDGE PL. 19[illegible] X [illegible] ([illegible] X 1'-7[illegible]) [illegible]	5	0 [illegible]	CO
15-8	4	FLG. PL. 27½ O.D. X 1 FIN. X 20⅝ I.D.			CO
		(27[illegible] X 1[illegible] X 2'-3[illegible])			
15-9	4	FLG. PL. 27½ O.D. X ½ X 20⅝ I.D.			A 283-C
		(28 X 2'-4 [illegible])			
15-10		STAINLESS STEEL STRAINER ASSY.			*
15-B		20" HEADER SECTION			
15-5	12	PL. 148 [illegible] X ⅜ KSK. (62 X 12-[illegible]) [illegible]	5	1 [illegible]	[illegible]
15-C		20" HEADER SECTION			
15-4	4	PL. 130 [illegible] X [illegible] KSK. (62 X 10-10[illegible]) [illegible]	5	1 [illegible]	[illegible]
15-11	2	PL. 3[illegible] X [illegible] (60[illegible] X 3'-0[illegible]) [illegible]	5	0 [illegible]	CO
15-12	2	PC. 12" ⌀ SCH. 80 SEAMLESS PIPE [illegible]	0	[illegible]	A333 GR 1
15-13	2	FLG. ONLY HEADS			A283 C
		([illegible] T=½ [illegible])			
15-D		20" HEADER SECTION			
15-4	2	PL. 130 [illegible] X [illegible] X SK. (62 X [illegible]-10[illegible]) [illegible]	5	1 [illegible]	[illegible]
15-14	1	PL. 3[illegible] X [illegible] (60[illegible] X 3'-0[illegible]) [illegible]	5	0 [illegible]	CO
15-15	1	PL. 12 X [illegible] X SK. (49[illegible] X 1'-0[illegible]) [illegible]	4	1 [illegible]	CO
15-16	1	FLG. & DISHED ASME CODE HEAD			A 283 C
		([illegible] T=½ (NOM) [illegible] 15")			
15-E		20" HEADER SECTION			
15-5	1	PL. 148 [illegible] X ⅜ X SK. (62 X 12'-4[illegible]) [illegible]	5	1 [illegible]	[illegible]
15-17	1	PL. 34[illegible] X ⅝ X SK. (62 X 2'-10[illegible]) [illegible]	5	1 [illegible]	CO
15-19	1	PL. 3[illegible] X [illegible] (60[illegible] X 3'-0[illegible]) [illegible]	5	0 [illegible]	CO
15-A	1	PIPE CAP FOR 6" ⌀ PIPE ([illegible])			
15-18	1	PL. 78 X ⅜ (62 X 6'-6[illegible]) [illegible]	5	1 [illegible]	[illegible]
15-20	1	PC. 6" ⌀ SCH 80 SEAMLESS PIPE [illegible]	C	8	A333 GR 1
15-22		MAKE-UP PL. - 12 X [illegible] (62 [illegible] X 1'-0[illegible]) [illegible]	5	1 [illegible]	[illegible]
		HEX HD BOLTS ⅝-11 W/HEX NUTS	0	2 [illegible]	TP. 304
15-F		20" HEADER SECTION			
15-1	4	PL. 128 [illegible] X [illegible] X SK. (62 X 10'-8[illegible]) [illegible]	5	1 [illegible]	[illegible]
15-2	2	PL. 40 X [illegible] (60[illegible] X 3'-4[illegible]) [illegible]	5	0 [illegible]	CO
15-23	2	PL. 16 X [illegible] X SK. (60[illegible] X 1'-4[illegible]) [illegible]	5	0 [illegible]	CO
15-24	2	FLG. & DISHED A.S.M.E. CODE HEAD			A283 C
		([illegible] T=½ (NOM) [illegible])			

MONTICELLO PROJECT

DETAILS [illegible] FOR [illegible]

CHICAGO BRIDGE & IRON COMPANY

20" Ø HEADER
FOR SUPPRESSION CHAMBER

PURCHASER'S NO. 205-55552-[illegible]
CONTRACT NO. 9-5625
DRAWN BY P.W.L. DATE 12-13-66
CHECKED BY R.E.F. DATE [illegible]-67
DWG. NO. 215-5

CERTIFIED BY VENDOR
APPROVED
BY [illegible]
DATE 8-17-67

DISTRIBUTION

FIELD			
QUAL.			
CIVIL			
ELECT.			
LAYOUT			
MECH.			
PURCH.			
EXPED.			
PROJECT			
SCHED.			
START-UP			

BECHTEL CORP.
SAN FRANCISCO

MONTICELLO NSP
GENERAL ELECTRIC
APED - SAN JOSE
VPF # 1812-78-16-11

SEP 6 1967

NUMBER MONTICELLO CORE SPRAY DATE 5/18/87
SUBJECT NPSH AT SHORT TERM RUNOUT BY R.T. REICH SHEET A-1 OF 4

INPUT DATA

TEMPERATURE OF POOL 137°F (SAR REV.2 FIG 5.2-17)
FOR SHORT TERM (< 10 MIN)
ONE STRAINER PLUGGED
FEET PER PSI = 2.344
4 PUMP RHR FLOW, TOTAL = 15,150 gpm (257HA423AE, REV. 5)
RHR FLOW = 15,150/2 = 7575 gpm FOR TWO PUMPS
HPCI FLOW = 0
RCIC FLOW = 0
REACTOR PRESSURE = "0" PSID OVER WETWELL PRESSURE SO RCIC AND HPCI CANNOT FUNCTION (IMPLIES A DESIGN BASIS LOCA).
POOL AMBIENT PRESSURE = $\frac{1}{2}$ OF SAR REV 2 PRESSURE AT 10 MIN
" " " = 8.2 / 2 = 4.1 PSIG.

(1) TO MAXIMIZE CORE SPRAY RUNOUT FLOW, MINIMIZE SUCTION LOSSES BY USING DATA FROM SHEET C-6 (SUCTION LOSSES WITH ONLY CORE SPRAY FLOW)

$\Delta H_{FRICTIONAL}$ (SUCTION) = 4.89 feet @ 3300 gpm pump flow

ΔH frictional (DISCHARGE) = 241.5 feet @ 3020 gpm (SHEET C-4)

ΔH ELEVATION (POOL TO C/S SPARGER) = 89.16 − 11.1 = 78.06 FEET, (PROCESS DIAGRAM DATA 161F301, R2)

SYSTEM RESISTANCE CURVE (BASED ON DISCHARGE FLOW)

$$R = 78.06 + \left(\frac{Q}{3020}\right)^2 (241.5 + 4.89)$$

MAXIMUM RUNOUT FLOW IS 4370 gpm (DISCHARGE LINE)

Q (GPM) (REACTOR FLOW)	TDH (feet)	R	TDH − R (feet)	TDH − R (PSI)
4300	600	577	23	9.5
4350	600	589	11	4.7
→ 4370	596	594	—	--
4500	580	625	−45	—

GENERAL ELECTRIC CO.

Nuclear Energy Business Operations

ENGINEERING CALCULATION SHEET

NUMBER: MONTICELLO CORE SPRAY — DATE: 5/12/87

SUBJECT: NPSH AT SHORT TERM RUNOUT — BY: R.T. REICH — SHEET A-2 OF 4

① CONTINUED

CALCULATE CORE SPRAY MINIMUM FLOW AT RUNOUT CONDITIONS

FROM SHEET E, MINIMUM FLOW ≈ 260 gpm AT 3000 gpm measured total Flow

THEREFORE PUMP FLOW = 3000 + 260 = 3260 gpm.

PUMP TDH AT 3260 gpm, ≈ 702 FEET OR ≈ 300 psig.

PUMP TDH AT 4370 + 200 OR 4570 gpm IS 570 FEET OR 244 psig.

TO CALCULATE THE MINIMUM FLOW AT RUNOUT CONDITIONS

$$Q = 260\left(\frac{244}{300}\right)^2 = 234 \text{ gpm}$$

THEREFORE, AT RUNOUT FLOW OF 4370 gpm PUMP FLOW IS

$4370 + 234 \approx 4600$ gpm

$.016312$
$V_f \times 144$

② CALCULATE NPSH AT <10 MINUTES IN RUN OUT CONDITION

TEMPERATURE OF POOL 137°F, FEET / PSI = 2.340, VAPOR PRESSURE = 2.6729 ft — 3.1997

144°F — 2.349 — " " = 6.265 ft — 7.516 ft

ASSUME NEAR STRAINER IS PLUGGED AND RHR AND C/S ARE SUPPLIED FROM THE FAR STRAINER ON THE SAME SIDE OF THE TORUS.

TOTAL FLOW = 7575 (RHR) + 4600 (C/S) = 12,175 gpm

ⓐ 20" PORTION OF SUCTION PIPING FRICTION LOSSES

EQUIVALENT FEET OF 20" DIA HEADER PIPE (ID = 1.604 ft)

	L/D	EXTEND	EQUIV. LENGTH (FT.)
3 MITER BENDS (22.5°)	5	15	23.75
1 TEE ON OUTLET	60	60	95.0
ENTRANCE LOSS (K=.47)	37	39	61.75
PIPE			75.0
			255.50 ft.

NUMBER MONTICELLO CORE SPRAY DATE -1.0/87
SUBJECT NPSH AT SHORT TERM RUNOUT BY R.T. FEICH SHEET A-3 OF 4

(2) CONTINUED

STRAINER LOSS = 1.0 FT / 10,000 gpm (VPF 1812-78-4)

FOR 12,175 gpm, STRAINER LOSS = $\left(\frac{12,175}{10,000}\right)^2 (1.0) = 1.482$ FEET

PIPING HEAD LOSS

$D = 1.604$ FT.

$\rho = 61.538$ lbs/ft³

$\mu = 29 \times 10^{-5}$ lbs/ft sec.

$v = \frac{12,175}{(60)(7.48)(2.021)} = 13.42$ ft/sec.

$Re = \frac{v D \rho}{\mu} = \frac{(13.42)(1.604)(61.538)}{29 \times 10^{-5}}$

$Re = 4.79 \times 10^{+6}$

Then $f = 0.0122$

$h_L = f\left(\frac{L}{D}\right)\left(\frac{v^2}{2g}\right)$

$\frac{L}{D} = \frac{255.5}{1.604} = 159.3$

$\frac{v^2}{2g} = \frac{(13.42)^2}{64.4} = 2.797$ ft

$h_L = (0.0122)(159.3)(2.797)$

$h_L = 5.436$ ft

TOTAL 20" LOSS = 5.436 + 1.482 = 6.92 FT AT 12,175 gpm

(b) 12" PORTION OF SUCTION PIPING FRICTION LOSSES.

FOR EQUIVALENT LENGTH SEE C-6 ($L/D = 231$)

$Q = 4600$ gpm, $ID = 1.0075$ ft, $\rho = 61.538$ lbs/ft³

$v = 9.226\left(\frac{4600}{3300}\right) = 12.86$ ft/sec., $\mu = 29 \times 10^{-5}$ lbs/ft sec.

$Re = \frac{v D \rho}{\mu} = \frac{(12.86)(1.0075)(61.538)}{29 \times 10^{-5}} = 2.749 \times 10^{6}$ $\therefore$ $f = 0.0135$

$h_L = f\left(\frac{L}{D}\right)\left(\frac{v^2}{2g}\right) = 0.0135(231)\left(\frac{(12.86)^2}{64.4}\right) = 8.008$ ft

NUMBER MONTICELLO CORE SPRAY DATE 5/1/87

SUBJECT NPSH AT SHORT TER BY

(2) CONTINUED

(c) CALCULATE NPSH AT 137°F TEMPERATURE AND 10 MINUTE RUNOUT

$NPSH_A = P_A + \Delta H_{ELEV} - \Delta H_{friction} - \Delta H_{vapor\ press}$

$\Delta H_{elevation} = 12.0$ ft (see C-1)

$\Delta H_{friction} = 8.008$ ft (see A-3) (12")

$= 6.92$ ft (see A-3) (20")

$\Delta H_{vapor\ press} = \cancel{6.265}$ 7.516 ft (see A-2)

$NPSH_A = (14.7 + 4.1)\ \cancel{2.344}\ 2.349 + 12.0 - 8.008 - 6.92 - \cancel{6.265}\ 7.516$

$NPSHA = \cancel{34.87}$ 33.717 FT

* COMMENT - INCREASE IN SUCTION LOSSES HAS A NEGLIGIBLE AFFECT ON C/S RUNOUT FLOW

NUMBER Monticello Core Spray NPSHA DATE 5/22/87
SUBJECT Long Term Acc, Temp = 179°F BY R.T. Reich SHEET B-1 OF 3

P_A $O_{DOO}L$ = 161 PSIG (FSAR FIG 5.7-15)

① CONDITIONS: (EACH SIDE) 1 RHR PUMP @ 4000 GPM (779E510, Rev 3)
1 CORE SPRAY @ 3310 GPM (161F301, Rev 2)

② ASSUMPTIONS: ALL CORE SPRAY AND RHR FLOW COME FROM THE FAR STRAINER AS THE NEAR STRAINER IS 100% PLUGGED. STRAINER LOSS = 1.[illegible]/10000 GPM

③ STRAINER LOSS

TOTAL FLOW = 4000 + 3310 = 7310 GPM

$$\Delta H_f = \left(\frac{7310}{10,000}\right)^2 1.0 = \underline{\underline{0.53\ ft}}$$

④ RING HEADER LOSS — 20" OD, 3/8" WALL (STD), ID = 1.60[illegible]
X AREA = 2.02 ft²

FROM SHEET A-3, EQ LENGTH = 255.5 ft

$$\frac{L}{D} = \frac{255.5\ ft}{1.609\ ft} = 159.3$$

CALC REYNOLDS NO. D = 1.604 ft

$$Re = \frac{D v \rho}{\mu}$$

ρ = 60.61 #/ft³ @ 179°F

$$v = \frac{7310\ gal}{min} \times \frac{1\ min}{60\ sec} \times \frac{1\ ft^3}{7.48\ gal \times 2.02\ ft^2}$$

$$Re = \frac{1.604 \times 6.058 \times 60.61}{21.5 \times 10^{-5}}$$

v = 8.058 ft/sec

$Re = 3.644 \times 10^6$

$\mu = 21.5 \times 10^{-5}$ #/ft-sec

$$\frac{h_L}{\left(\frac{L}{D}\right)\frac{v^2}{2g}} = .0123$$

$$\frac{v^2}{2g} = \frac{(8.058)^2}{64.4} = 1.008$$

$$h_L = .0123\ (159.3)(1.008) = \underline{\underline{1.975\ ft}}$$

TOTAL 20" LOSS = 1.975 ft + 0.53 ft = $\underline{\underline{2.505\ ft}}$

NUMBER Monticello Core Spray NPSH$_A$ DATE 5/26/87
SUBJECT Long Term Case, Temp = 179°F BY R.T. Reed SHEET B-2 OF 3

⑤ 12" SUCTION PIPE LOSS, ID = 1.0075 ft
X AREA = 0.797 ft^2

FROM SHEET C-6, L/D = 231

CALC REYNOLDS NO.

$$Re = \frac{D v \rho}{\mu}$$

D = 1.0075 ft
ρ = 60.61 #/ft^3

$$v = \frac{3310\ gpm \times 1\ min \times 1\ ft^3}{min \quad 60\ sec \times 7.48\ gal \times .797}$$

v = 9.254 ft/sec

μ = 21.5×10^{-5} #/ft-sec

$$Re = \frac{1.0075 \times 9.254 \times 60.61}{21.5 \times 10^{-5}}$$

Re = 2.628 ×10^6

$$\frac{h_L}{\left(\frac{L}{D}\right)\left(\frac{v^2}{2g}\right)} = .0135$$

$$\frac{v^2}{2g} = \frac{(9.254)^2}{64.4} = 1.33$$

h_L = .0135 (231)(1.33) = 4.147 ft.

⑥ CALC NPSHA BASED ON SAR DATA FOR A DBA.
NPSH$_A$ = AMBIENT PRESS. + ELEVATION HEAD − FRICTION − V. PRESS
(FROM SAR FIG. 5.2-15, FOR DBA)
POOL AMBIENT PRESSURE (WHEN T$_{POOL}$ = 179°F) = 16.0 PSIG
FEET/PSI = 2.376, ΔH ELEV. = 12.0 feet
VAPOR PRESS = 7.345 PSIA
NPSHA = ($\frac{16}{2}$ + 14.7)(2.376) + 12.0 − 4.147 − 2.505 − 7.345 (2.376)
NPSHA = (22.7)(2.376) + 12.0 − 4.147 − 2.505 − 7.345(2.376)
NPSHA = 41.8 feet, REQUIRED = 29 feet.

NUMBER Monticello Core Spray NPSH DATE 5/?/87
SUBJECT Long Term Case, Temp = 179°F BY [illegible] SHEET B-3 OF 3

① RECALCULATE NPSHA USING PROCESS DIAGRAM VALUES FOR SUPPRESSION POOL PRESSURE
$P_A = 16.9$ PSIA

— MODE C-2 OF (729E510, Rev 3) SHOWS ONLY ONE RHR PUMP OPERATING, AND RESULTS IN THE PEAK POOL TEMP. OF 179°F.

— ASSUME 1/2 TOTAL FLOW FROM ~~EACH~~ STRAINER (CONSERVATIVE)

$\frac{1}{2}$ FLOW = 7310 / 2 = 3655/STRAINER

— STRAINER LOSS = $\left(\frac{3655}{10{,}000}\right)^2 1.0 = 0.134$ ft

— REYNOLDS NO. = $3.644 \times 10^6 / 2 = 1.822 \times 10^6$ (SHT B-1)

$$\frac{h_L}{\left(\frac{L}{D}\right)\frac{v^2}{2g}} = .0128$$

$v = \frac{8.056}{2} = 4.014$

$\frac{v^2}{2g} = 0.250$

$\frac{L}{D} = 159.3$ (SHT B-1)

$h_L = .0128 (159.3)(0.250) = 0.51$ (20" PIPE)

TOTAL 20" LOSS = 0.51 + 0.134 = 0.644 ft.

— FROM SHT B-2, h_L FOR 12" SECTION = 4.147 ft

— $NPSH_A = 16.9(2.376) + 12.0 - 4.147 - 0.620 - 7.345(2.376)$

$NPSH_A = 29.91$ ft

FROM PUMP CURVE (BINGHAM 26604), $NPSH_R = 29$ ft

* COMMENT - LONG TERM AT THIS TEMPERATURE LASTS < 5 HOURS

GENERAL ELECTRIC CO.
Nuclear Energy Business Operations
MONTICELLO
ENGINEERING CALCULATION SHEET

NUMBER CORE SPRAY PUMP LINE LOSSES DATE

SUBJECT NORTH STATES POWER DRWG NX 13142-31 AND LINE FRICTION SEGMENT. BY E.T.

① Δ ELEVATION OF TRANSMITTER ABOVE PUMP ℄ (SITE MEASUREMENT)

Δ ELEV. = 13.25 FT

② FRICTION LOSS AT 3100 gpm (PUMP A IS WORST) TO GAGE

10" Sch. 40 PIPE D = 0.835 ft

	No	L/D	EXTEND	EQUIV. FT.
90° ELS	3*	2/20 + 1/30	70	58.45
45° ELS	1	16	16	13.36
CHK. VALVE	1	100	100	83.5
PIPE	7	—	—	7.0
TEE ON RUN	1	20	20	16.7
TOTAL				179.01 FT.

* 1 SR EL.

ΔP/100 FT AT 3100 GPM — 10" SCH. 40

AT 3500 GPM, ΔP/100 = 2.38 psi

AT 3100 GPM, $\Delta P/100 = \left(\frac{3100}{3500}\right)^2 2.38 = 1.867$ psi

③ FRICTION LOSS FROM PUMP DISCHARGE TO GAGE AT 3100 GPM

$\Delta H = 1.867 \frac{(PSI)}{100 (FT)} 179 (FT) = 3.34$ psi

$\Delta H = 3.34 (2.31) = 7.72$ FT FRICTION DURING PREOP SPECIAL TESTS AT 3100 GPM MEASURED

④ TOTAL LOSS FROM PUMP DISCHARGE TO DISCHARGE GAGE =

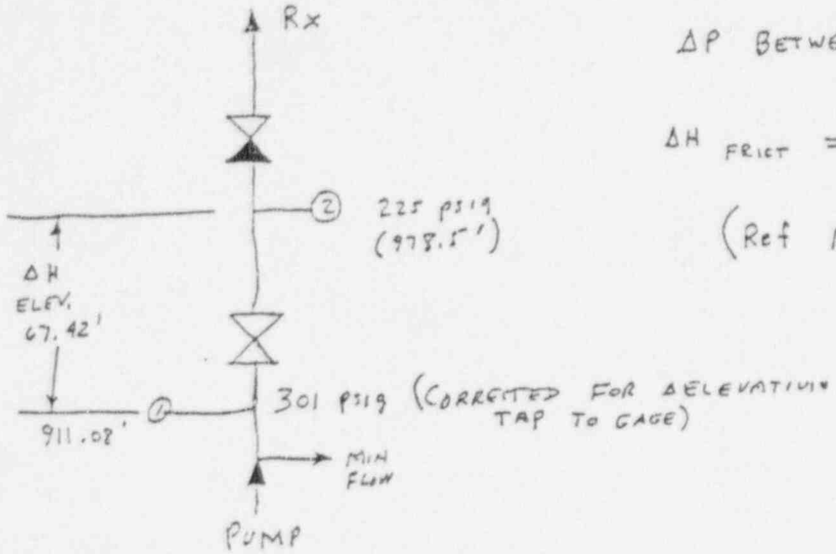
7.72 + 13.25 = 20.97 FT AT 3100 GPM MEASURED FLOW.

MONTICELLO

NUMBER CORE SPRAY PUMP LINE LOSSES DATE

SUBJECT SPECIAL PREOP TESTS BY E.T. KLECIT SHEET C-2 OF 6

(5) RESULTS OF SPECIAL TEST WITH THROTTLED VALVES.
(PREOP DATA) AT 3100 GPM (MEASURED)

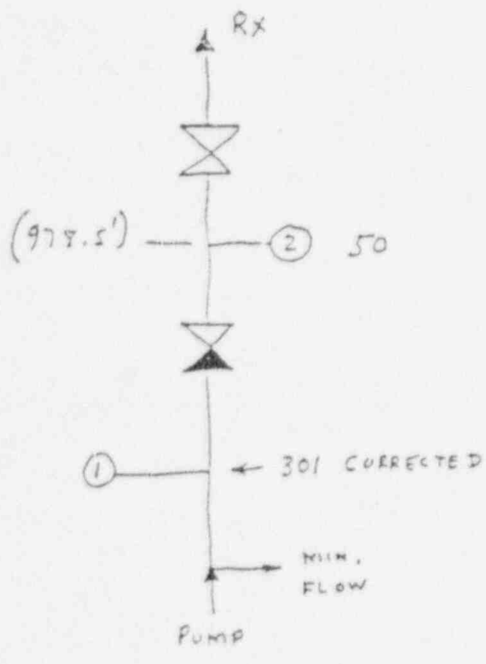


ΔP BETWEEN 1 AND 2 = 76 psi

$\Delta H_{FRICT} = 76\,(2.31) - 67.4 = 108.2$ ft

(Ref NX 13142-31)

(6) RESULTS OF SPECIAL TEST WITH THROTTLED VALVES
(PREOP DATA) AT 3100 GPM (MEASURED)



ΔH ELEVATION GAGE 2 TO CORE SPRAY
SPARGER ELEVATION 987 FT.

$\Delta H = 987 - 978.5 = 8.5$ FT

$\Delta H_{FRICT} = 50\,(2.31) - 8.5 = 107$ FT.

MONTICELLO

NUMBER CORE SPRAY PUMP LINE LOSSES DATE

SUBJECT DISCHARGE LINE FRICTIONAL LOSSES BY R TIRESCO SHEET OF 6

(7) SUM UP C/S DISCHARGE LINE FRICTION LOSSES AT 3100 GPM

$$\Delta H_{fd} = 7.72 + 108.2 + 107 = 222.9 \text{ FT.}$$

(8) SUBSEQUENT SYSTEM CHANGES

13 PSI ADDED TO CONTROL ORIFICE AT 3020 GPM – RATIO TO 3100 GPM FOR CONSISTENCY

$$13\left(\frac{3100}{3020}\right)^2 (2.31) = 31.6 \text{ FT AT 3100 GPM.}$$

(9) CURRENTLY INSTALLED DISCHARGE FRICTION LOSSES AT 3100 GPM =

$$222.9 + 31.6 = 254.5 \text{ FT.}$$

MONTICELLO

NUMBER CORE SPRAY PUMP LINE LOSSES DATE

SUBJECT PUMP DISCHARGE PRESSURE BY R.T. REICH SHEET C-4 OF 6

(10) CALCULATE REQUIRED PUMP DISCHARGE PRESSURE AT SHORT TERM CONDITIONS, TEMP. POOL = 120°F AND RATED FLOW

a. CORE SPRAY SPARGER ELEVATION = 987 FT.
b. CORE SPRAY PUMP CENTER LINE = 897' 10"
c. ELEVATION PUMP TO SPARGER = 89' 2"
d. ASSUME SUCTION PRESSURE = 12.45 psia = 29 FEET.
e. ASSUME POOL AMBIENT PRESSURE = 14.7 psia (SHORT TERM) = 34.25 FEET.
f. MINIMUM FLOW ≈ 260 GPM
g. RATED FLOW = 3020 GPM
h. FRICTION LOSS AT 3020 GPM = $\left(\frac{3020}{3100}\right)^2 254.5 = 241.5$ FT.
i. PRESSURE HEAD (130 psi) 2.33 + (34.25 − 29) FT = 308.2 FT.
j. TOTAL PUMP HEAD = PRESSURE + FRICTION + ELEVATION + SUBMERGENCE
= 308.2 + 241.5 + 89.2 + 4.0 = 642.9 FT

WITH MIN. FLOW OF 260 GPM GIVES PUMP FLOW OF 3280 GPM.

k. RECENT PUMP TESTS INDICATE NO DEGRADATION OF THE CORE SPRAY PUMP. THE PUMP CURVE (BINGHAM − WILLAMETTE CURVE 26604) SHOWS ≈ 698 FEET AT 3280 GPM. WITH MINIMUM NPSH AVAILABLE. NORMALLY THE MINIMUM NPSH OCCURS SOME TIME AFTER THE FIRST TEN MINUTES POST LOCA, SO THE ANALYSIS ABOVE IS CONSERVATIVE.
l. SUPPRESSION POOL DOWNCOMER SUBMERGENCE = 4.0 FT

(11) REQUIRED DISCHARGE PRESSURE UNDER TEST CONDITIONS TO DEMONSTRATE DESIGN CAPABILITY.

P_d REQUIRED = TDH FROM 10-j ABOVE + Δ SUCTION PRESSURE FROM TEST CONDITIONS TO 29 FT. OF NPSH

P_d REQD = 642.9 FT + 34.25 FT. + 12 FT ELEVATION (POOL ABOVE PUMP) − 29 FT.

P_d REQD = 642.9 FT + 17 FT = 659.9 / 2.316 = 284.8 PSIG

MONTICELLO

NUMBER: CORE SPRAY PUMP LINE LOSSES DATE:
SUBJECT: SUCTION PIPING LOSSES BY R.T. REICH SHEET C-5 OF 6

(12) 20" PORTION SUCTION PIPING FRICTIONAL LOSSES

a. CORE SPRAY FLOW = 3280 GPM, USE 3300 GPM.

b. ALL FLOW FROM NEAR STRAINER

c. EQUIVALENT FEET OF 20" HEADER PIPE (ID = 1.5833 FT.)

ITEM	L/D	EXTEND	EQUIV. LENGTH
1 MITER BEND (22.5°)	5	5	7.917
1 TEE ON OUTLET	60	60	95.0
ENTRANCE LOSS (K=.47)	39	39	61.75
PIPE	—	—	25.0
			189.667 FT

d. STRAINER LOSS = 1.0 FT/10,000 gpm (VPF 1812-78.4)

FOR 3300 gpm

$$\Delta H = \left(\frac{3,300}{10,000}\right)^2 (1.0) = 0.109 \text{ ft.}$$

e. 20" PIPE LOSS = $\frac{0.129 \text{ psi}}{100 \text{ FT}}$ AT 3500 GPM (CRANE CATALOG)

THEN AT 3300 GPM, $\Delta P = \left(\frac{3300}{3500}\right)^2 (0.129) = \frac{0.115 \text{ psi}}{100 \text{ ft}}$

$$\frac{0.115 \text{ (psi)}}{100 \text{ ft}} \, 2.316 \left(\frac{\text{ft}}{\text{psi}}\right) = \frac{0.266 \text{ ft}}{100 \text{ ft}} \text{ AT 3300 GPM.}$$

f. ΔH FOR 20" PIPE $= \frac{0.266 \text{ FT}}{100 \text{ FT}} (189.7 \text{ FT}) + 0.109 \text{ FT}$

ΔH (20" PIPE) = 0.614 FT AT 3300 GPM.

(13) 12" PORTION (SCHEDULE STD) DATA FROM DWG NSP NX 13142-20, R.D.

DIA = 1.0075 FT.

ITEM	L/D	EXTEND	EQUIV. LENGTH
7 90° ELS	20	140	141.
1 TEE ON RUN	20	20	20.2
2 GATE VALVES	13	26	26.2
1 ENTRANCE LOSS (K=.23)	18	18	18.1
STR. PIPE	—	—	30.
			235.5 FT

MONTICELLO — ENGINEERING CALCULATION SHEET

NUMBER CORE SPRAY PUMP LINE LOSSES DATE

SUBJECT SUCTION PIPING LOSSES BY R.T. REICH SHEET C-6 OF 6

(13) CONTINUED

REYNOLDS NUMBER AT 3300 GPM

$D = 1.0075$ FT, $A = 0.797$ FT^2

$\rho = 62.15$ Lbs/FT^3 AT 80°F, TEST

$\mu = 50 \times 10^{-5}$ Lbs/SEC. FT AT 80°F,

$$v = \frac{3300}{(60)(7.48)(.797)} = 9.226 \text{ FT/SEC.}$$

$$Re = \frac{vD\rho}{\mu}$$

$$Re = \frac{(9.226)(1.0075)(62.15)}{50 \times 10^{-5}} = 1.155 \times 10^{6}$$

Then $f = 0.014$

$$h_L = f\left(\frac{L}{D}\right)\left(\frac{v^2}{2g}\right)$$

$$\frac{L}{D} = \frac{235.5}{1.0075} = 231$$

$$\frac{v^2}{2g} = \frac{(9.226)^2}{64.4} = 1.321$$

$$h_L = 0.014(231)(1.321)$$

$= 4.272$ FT loss IN 12" SUCTION PIPING AT 80°F

(14) TOTAL SUCTION LOSS AT 80°F $= 4.272 + 0.614 = 4.89$ FT.

NOTE: THIS FIGURE IS VERY CLOSE TO THE ESTIMATED VALUE OF 5 FT IN ITEM (11), SO:

(15) REQUIRED PUMP DISCHARGE PRESSURE AT 3300 GPM SUCTION FLOW

$$P_D = \frac{659.7 - 5.0}{2.316} = 282.7 \text{ psig AT PUMP DISCHARGE}$$

$$P_G = 282.7 - \frac{21.0}{2.316} = 273.6 \text{ psig AT PUMP DISCHARGE GAGE}$$

NUMBER Monticello Core Spray NPSHA DATE 5/26/87
SUBJECT Long Term core, $T_{supp} = 165°F$ BY R.T. Reid SHEET D-1 OF 3

184°F peak temp

feet/PSI = 144x ~~.01662~~ .016534 = ~~2.3695~~ 2.3808

VAPOR PRESSURE = ~~5.335~~ 8.203 PSIA

① CALCULATE NPSH A USING DATA FROM MODE C-1 OF RHR PROCESS DIAGRAM (~~7296~~ 510, Rev 3)

Torus P at Peak pool Temp 16.3 psig 50%

P_A POOL = ~~17.8 PSIA~~ 8.15 + 14.7 = 22.85 PSIA

2 RHR PUMPS @ 4000 GPM EACH, TOTAL 8000 GPM
1 C/S PUMP @ 3310 GPM
ADJACENT STRAINER PLUGGED
NO OTHER ECCS PUMPS OPERATING

a. Calc RHR FLOW SPLIT 20" RING HEADER
L/D TO CLOSEST STRAINER = 159.3 ft (SHT A-3)

— CALC L/D TO C/S INTAKE . ID = 1.604'

	L/D	EXTEND	LENGTH
2 MITER BENDS (22.5°)	5	10	16
2 TEE ON RUN	20	40	64
PIPE			50
			13.0 eq. ft.

$L/D = \frac{130'}{1.604'} = 81$

— FIRST ASSUMPTION, 6000 GPM RHR FROM 1TS CLOSEST STRAINER & 2000 RHR FROM FAR STRAINER

6000 GPM STRAINER LOSS = $\left(\frac{6000}{10000}\right)^2 1.0$ = .36 ft

CALC. REYNOLDS NO. NEARER STRAINER

ρ = 60.90 #/ft³

$Re = \frac{D v \rho}{\mu}$

D = 1.604 ft

μ = 24.5x10⁻⁵ #/ft-sec

$Re = \frac{1.604 \times 6.618 \times 60.9}{24.5 \times 10^{-5}}$

$v = \frac{6000\ gal \times 1\ min \times 1\ ft^3}{min\ \ 60\ sec\ \ 7.48\ gal \times 2.02\ ft^2}$

$Re = 2.638 \times 10^6$

v = 6.618 ft/sec

NUMBER Monticello Core Spray NPSHA DATE 5/28/87
SUBJECT Long Term case, Temp = 165°F BY R.T. Beck SHEET D-2 OF 3

VA1

(1) (cont'd)
a. (cont'd)

$$\frac{h_L}{\left(\frac{L}{D}\right)\left(\frac{v^2}{2g}\right)} = .0125$$

$\frac{L}{D} = 159.3$

$\frac{v^2}{2g} = \frac{(6.618)^2}{64.4} = .680$

$h_L = .0125(159.3)(.680) = 1.354$ ft

TOTAL LOSS = 1.354 FT + .36 FT = 1.714 FT

CALC REYNOLDS NO. TO FAR STRAINER

COMBINED FLOW = 3310 (C/S) + 2000 (RHR) = 5310

INTERMEDIATE FLOW = 2000 GPM (RHR ONLY)

$Re = 2.638 \times 10^6 \left(\frac{5310}{6000}\right) = 2.33 \times 10^6$

$$\frac{h_L}{\left(\frac{L}{D}\right)\left(\frac{v^2}{2g}\right)} = .0127$$

$v = 6.618\left(\frac{5310}{6000}\right) = 5.86$

$L/D = 159.3$

$h_L = .0127(159.3)(.533)$

$\frac{v^2}{2g} = \frac{(5.86)^2}{64.4} = .533$ ft

$h_L = 1.079$ ft , STRAINER LOSS $= \left(\frac{5310}{10000}\right)^2 1.0 = 0.282$ ft.

INTERMEDIATE LOSS (FROM CRANE TABLES)

$h_L = \left(\frac{2000}{2500}\right)^2 \frac{.075 \text{ psi}}{100 \text{ ft}} (2.3645) \cdot 130 \text{ ft} = 0.1475$ ft

TOTAL LOSS = 0.282 + .1475 + 1.079 = 1.508 ft vs 1.714 ft above

∴ MORE RHR FLOW MUST BE IN WITH C/S FLOW

— SECOND ASSUMPTION 5800 GPM RHR FROM ITS CLOSEST STRAINER & 2200 RHR FROM FAR STRAINER

ASSUME NEGLIGIBLE CHANGE IN REYNOLDS NO & FRICTION FACTOR

NUMBER Monticello Core Spray NPSHa DATE 5/28/87
SUBJECT Long Term Case, Temp = 165°F BY R.T. Reed SHEET D-3 OF 3

① (cont'd)

a (cont'd) calc flow split – near strainer

STRAINER LOSS = $\left(\frac{5800}{10000}\right)^2 1.0 = .336$ ft

$v = 6.618\left(\frac{5800}{6000}\right) = 6.3974$ ft/sec

$h_L = .0125(159.3)\left(\frac{6.397^2}{64.4}\right) = 1.2655$ ft

TOTAL LOSS = 1.2655 + .336 = 1.602 ft

for strainer,

$v = 5.86\left(\frac{5510}{5310}\right) = 6.08$ ft/sec, $\frac{v^2}{2g} = 0.574$ ft

$h_L = .0127(159.3)(.574) = 1.161$ ft

STRAINER LOSS = $\left(\frac{5510}{10000}\right)^2 1.0 = .303$ ft

INTERMEDIATE LOSS (FROM CRANE TABLE)

$h_L = \left(\frac{2200}{2500}\right)^2 \left(\frac{.075 \text{ psi}}{100 \text{ ft}}\right)(2.3645)(130 \text{ ft}) = 0.1785$

TOTAL LOSS = .303 + .1785 + 1.161 = 1.643 ft

∴ RHR FLOW SPLIT ≅ 5850 FROM NEAR STRAINER AND 2150 FROM FAR STRAINER AND COMBINED C/S & RHR = 3310 + 2150 = 5460 gpm

STRAINER LOSS = $\left(\frac{5460}{10000}\right)^2 1.0 = 0.298$ ft

for 5460 gpm, $v = 5.86\left(\frac{5460}{5310}\right) = 6.0255$ ft/sec

$\frac{v^2}{2g} = 0.5638$ ft

$h_L = .0126(159.3)(.5638) = 1.132$ ft in 20" header

TOTAL LOSS = 0.298 + 1.132 = 1.430 ft

② CALC NPSH USING C/S ~~PUMP~~ SUCTION LOSS FROM SHEET B-2 FOR 3310 GPM

NPSHA = P_A + ΔH ELEV – FRICT. – VAPOR PRESSURE

NPSHa = ~~17.8~~ 22.85 (~~2.3645~~ 2.3808) + 12 – 1.430 – 4.147 – ~~5.335~~ 8.203 (~~2.3645~~ 2.3808)

NPSHA = 35.89 ft — OK – 29 ft REQ'D.

41.29

GENERAL ELECTRIC CO.
Nuclear Energy Business Operations
ENGINEERING CALCULATION SHEET

MONTICELLO

NUMBER CORE SPRAY PUMP LINE LOSSES DATE
SUBJECT EVALUATE MINIMUM BYPASS FLOW BY R.T. REICH SHEET E OF 1

① DATA FROM PREOP TESTING - SPECIAL TEST

FLOW (GPM) (MINIMUM FLOW LINE OPEN)	DISCHARGE PRESSURE (PSIG)	$\Delta(\Delta P)$
3000	300	—
2000	328	28
1000	339	11

FLOW (GPM) (MINIMUM FLOW LINE CLOSED)	DISCHARGE PRESSURE (PSIG)	$\Delta(\Delta P)$
3000	305	—
2000	331	26
1000	349	13

② DATA FROM BINGHAM PUMP CO CURVE 26604

$$\frac{\Delta Q}{\Delta P} = \frac{2500-3000}{743-720} = \frac{-500}{23} = -21.74 \ \frac{\text{GPM}}{\text{FT OF HEAD}}$$

$$\text{MIN. FLOW} = (21.74)(5)(2.31) = 251 \ \text{GPM}$$

BASED ON SITE DATA, ORIFICE CHARACTERISTICS, MIN FLOW OF 260 GPM WAS ASSUMED FOR A PROCESS FLOW OF 3000 GPM.

③ PUMP FLOW WITH MEASURED FLOW OF 3020 GPM IS 3280 GPM.

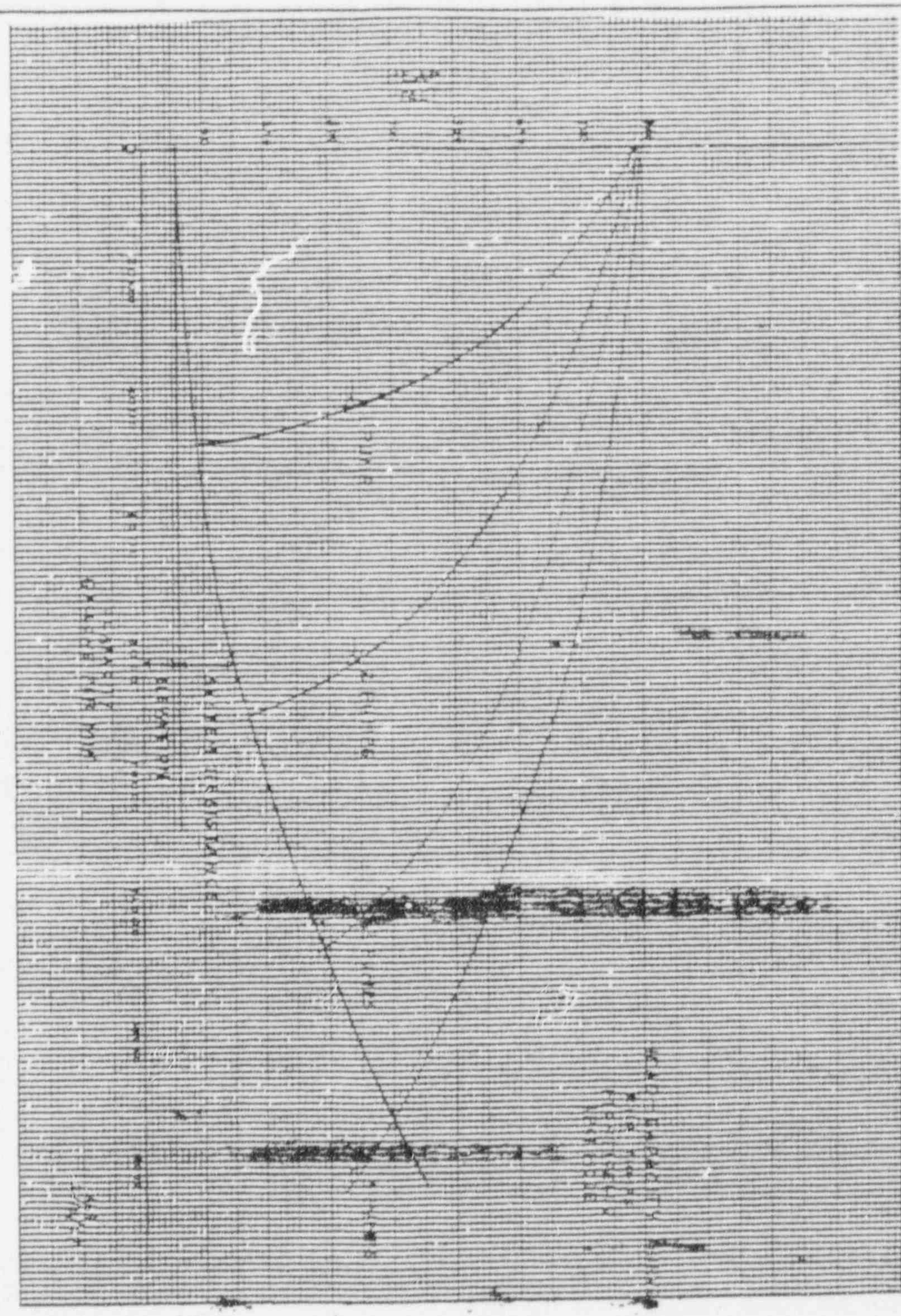
REFERENCES

GENERAL ELECTRIC
ATOMIC POWER EQUIPMENT DEPARTMENT

MONTICELLO

ENGINEERING FORM

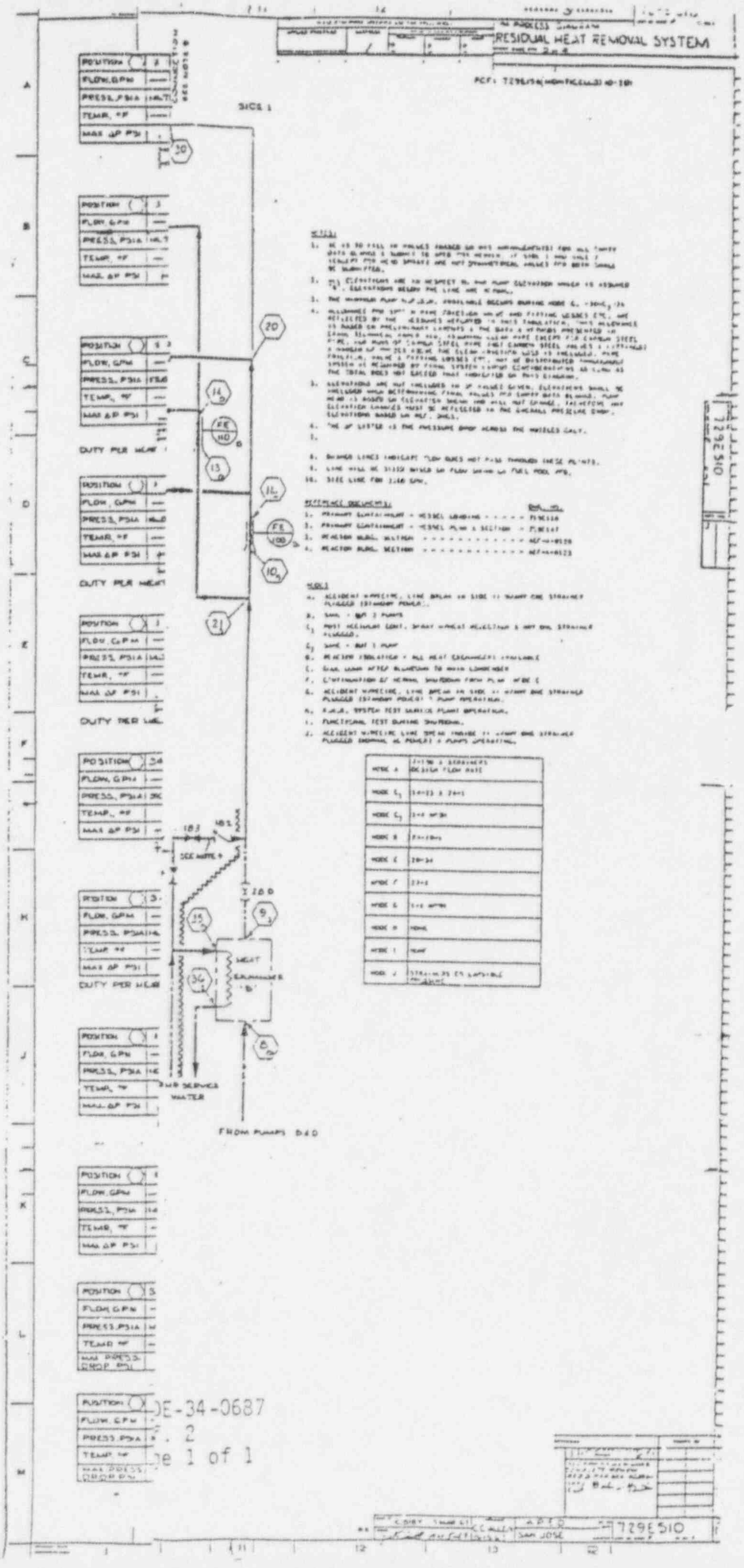
TITLE RESIDUAL HEAT REMOVAL SYSTEM DATA SHEET



EqDE-34-0687
Ref. 1
Page 1 of 1

BY		APPROVALS	REV NO. 5
			257HA423AE
ISSUED	APR 7 1970		CONT ON SHEET 6 SH NO. 5

NED - 749


RESIDUAL HEAT REMOVAL SYSTEM
729E510
POSITION
FLOW, GPM
PRESS, PSIA
TEMP, °F
MAX ΔP PSI
DUTY PER HEAT
HEAT EXCHANGER 'B'
RHR SERVICE WATER
FROM PUMPS B&D
SEE NOTE 4
MODE A
MODE B
MODE C
MODE D
MODE E
MODE F
MODE G
MODE H
MODE I
MODE J
MAX PRESS. DROP PSI
SAN JOSE
DE-34-0687
2
e 1 of 1

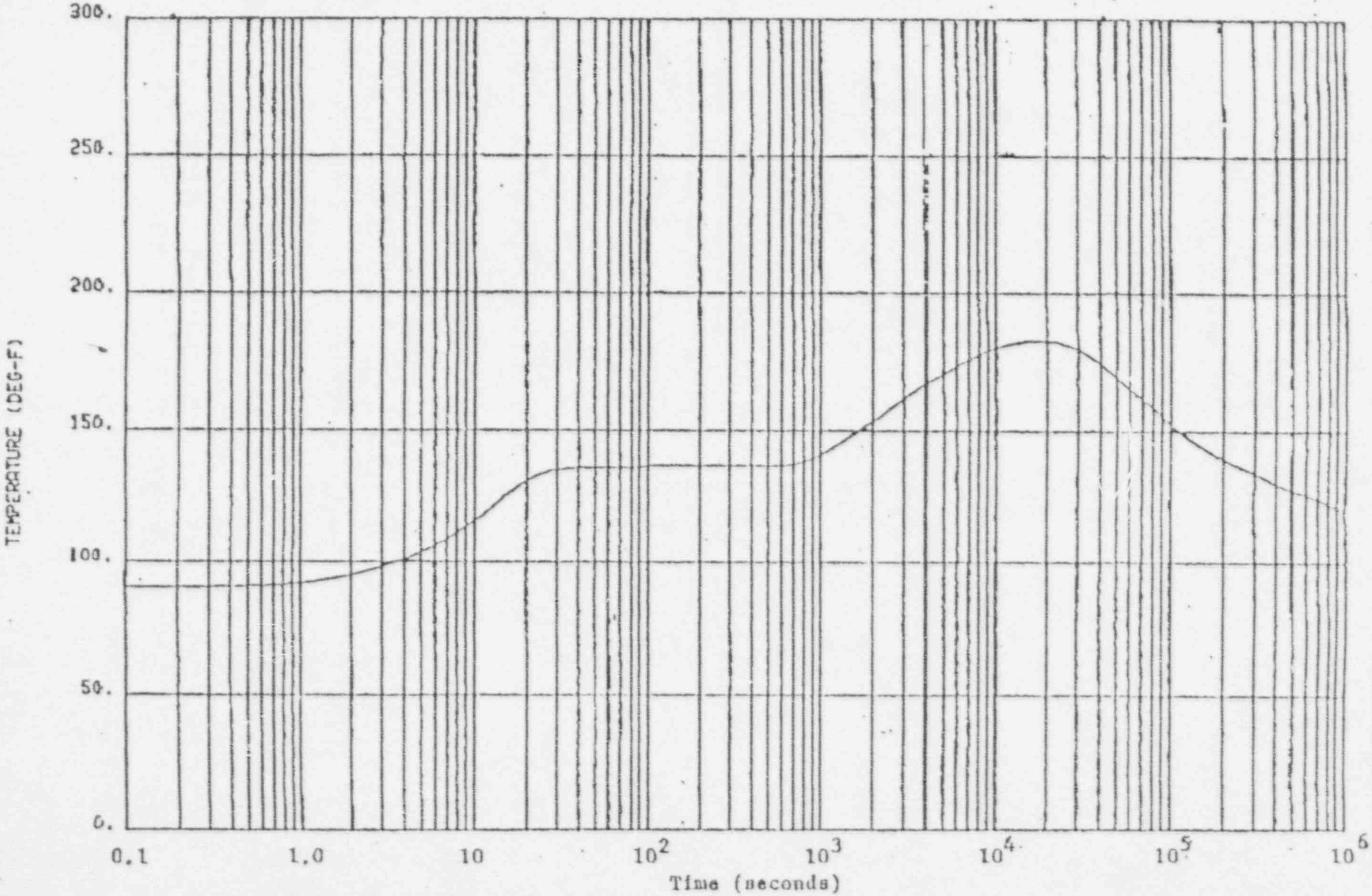
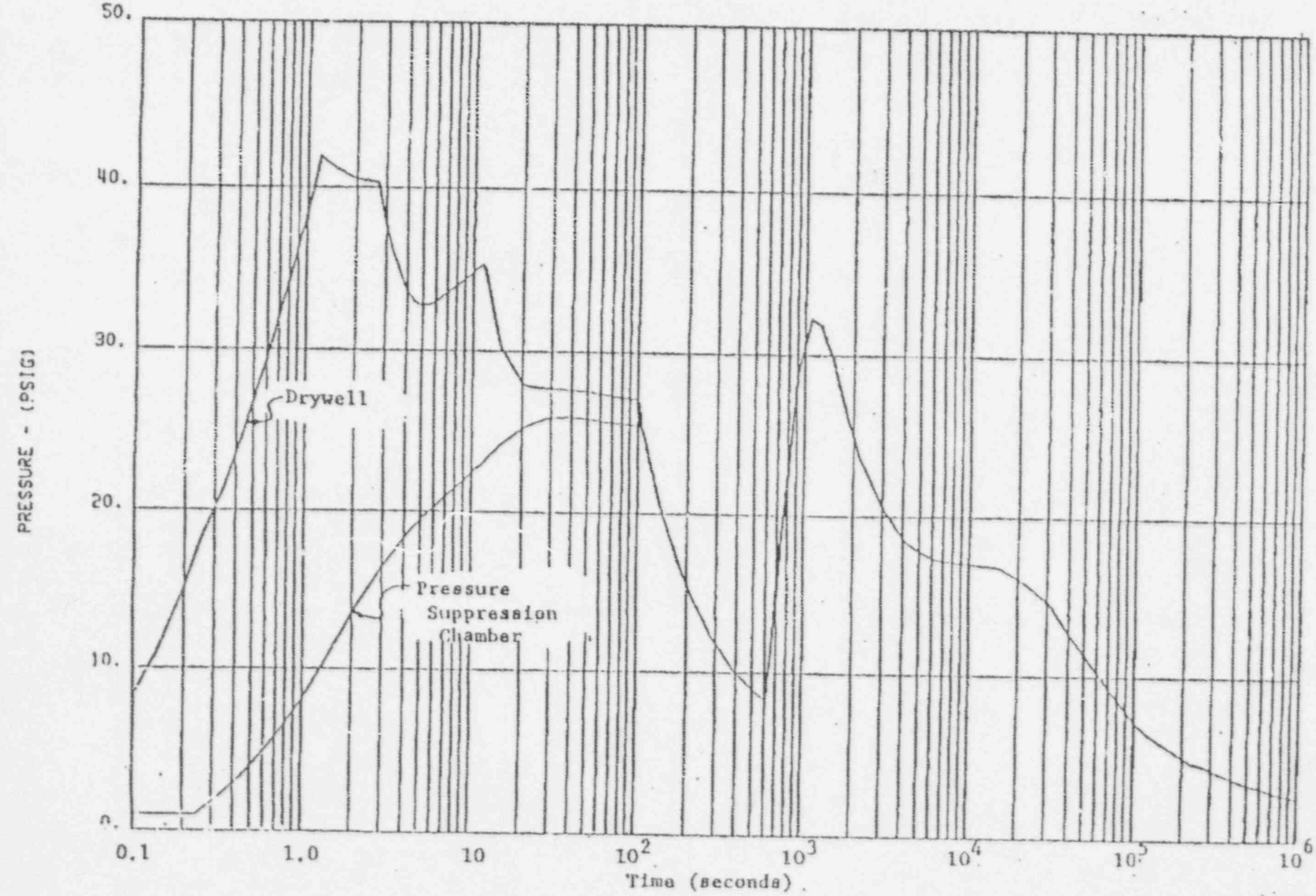


Figure 5.2-17 Suppression Pool Temperature Response

EqDE-34-0687
Ref. 3



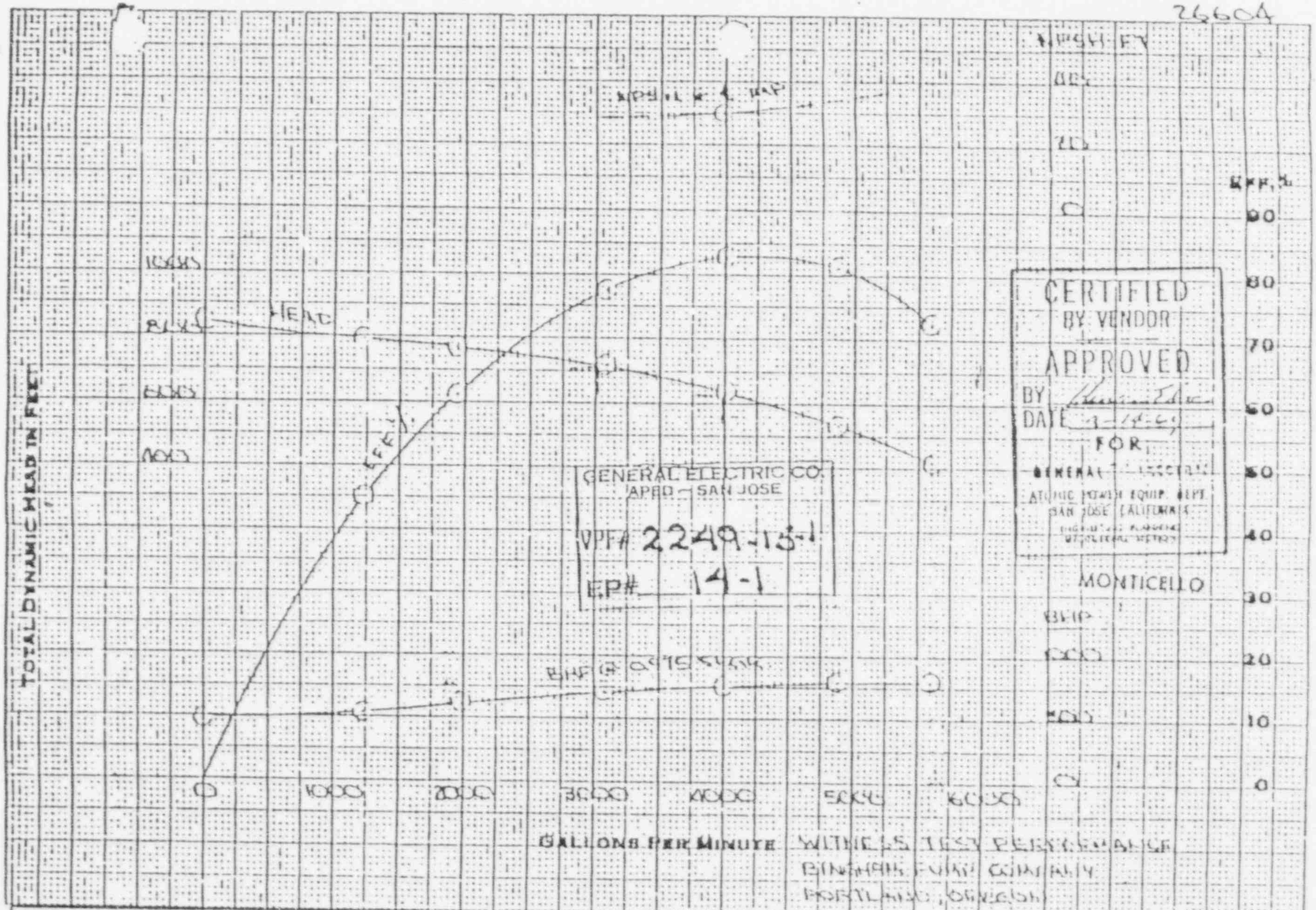
83-305

MONTICELLO

Figure 5.2-15 Containment Pressure Response to the Design Basis Accident   REV 2   10/83

EqDE-34-0637
Ref. 4
Page 1 of 1

26604



GENERAL ELECTRIC CO. APED MONTICELLO (NSF) CORE SPRAY PUMP 14-1 PUMP NO. 270418	CHARACTERISTIC CURVE SHEET BINGHAM PUMP CO. EqDE-34-0687 Ref. 5 OREGON	IMPELLER MAX. DIA. 14½ MIN. DIA. EYE AREA 72.2 SQ. IN.	10 x 12 x 14½ CVDS PUMP		
			DIA IMPELLER 13 11/16 NPSH REQUIRED	IMPELLER PATT. 1212 CVDS-1 REFERENCE	3560 R.P.M. CURVE NO 26604

E-101