NUREG-0828

Integrated Plant Safety Assessment
Systematic Evaluation Program

Big Rock Point Plant

Consumers Power Company
Docket No. 50-155

Final Report

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

May 1984

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ABSTRACT

The Systematic Evaluation Program was initiated in February 1977 by the U.S. Nuclear Regulatory Commission to review the designs of older operating nuclear reactor plants to reconfirm and document their safety. The review provides (1) and assessment of how these plants compare with current licensing safety requirements relating to selected issues, (2) a basis for deciding how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety when the supplement to the Final Integrated Plant Safety Assessment Report has been issued.

This report documents the review of the Big Rock Point Plant, which is one of ten plants reviewed under Phase II of this program. This report indicates how 137 topics selected for review under Phase I of the program were addressed. It also addresses a majority of the pending licensing actions for Big Rock Point, which include TMI Action Plan requirements and implementation criteria for resolved generic issues. Equipment and procedural changes have been identified as a result of the review.

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ACRONYMS AND INITIALISMS

ACRS	Advisory Committee on Reactor Safeguards
ADS	automatic depressurization system
AEOD	Office of the Analysis and Evaluation of Operational Data
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient(s) without scram
BTP	Branch Technical Position
BWR	boiling-water reactor
CAI	Commonwealth Associates, Inc.
CFR	Code of Federal Regulations
CPCo	Consumers Power Company
CPR	critical power ratio
CRO	control room operator
DBE	design-basis event
DER	design electrical rating
ECCS	emergency core cooling system
EHC	electrohydraulic control
EOF	Emergency Operations Facility
ERF	emergency response facility
ESF	engineered safety feature(s)
FMEA	failure modes and effects analysis
FRC	Franklin Research Center
FSHR	Final Hazards Summary Report
FTOL	full-term operating license
GDC	General Design Criterion(a)
GE	General Electric
gpm	gallons per minute
HEPB	high-energy-pipe break
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
ILRT	integrated leakage rate test
IPSAR	Integrated Plant Safety Assessment Report
IREP	Integrated Reliability Evaluation Program
ISI	inservice inspection
IST	inservice testing
LCO	limiting condition(s) of operation
LOCA	loss-of-coolant accident
MOV	motor-operated valve
mph	miles per hour
MSIV	main steam isolation valve
MSL	mean sea level
MWe	megawatt electric
MWt	megawatt thermal
NRC	Nuclear Regulatory Commission (U.S.)
ORLAS	Operating Reactors Licensing Actions Summary
ORNL	Oak Ridge National Laboratory
OSC	Operations Support Center

PCS	primary coolant system
PMF	probable maximum flood
PMP	probable maximum precipitation
PMS	probable maximum surge
POL	provisional operating license
PORV	power-operated relief valve
PRA	probabilistic risk assessment
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gage
PWR	pressurized-water reactor
QA	quality assurance
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RCW	reactor cooling water
RCWS	reactor cooling water system
RDS	rapid depressurization system
RG	Regulatory Guide
rpm	revolution(s) per minute
RPS	reactor protection system
RWCU	reactor water cleanup
RWS	radioactive waste system
SAI	Science Applications, Inc.
SAR	Safety Analysis Report
SALP	Systematic Assessment of Licensee Performance
SBLCS	standby liquid control system
SCS	shutdown cooling system
SDV	scram discharge volume
SEP	Systematic Evaluation Program
SER	Safety Evaluation Report
SPDS	safety parameter display system
SRP	Standard Review Plan
STS	Standard Technical Specification(s)
TER	Technical Evaluation Report
TMI	Three Mile Island
TRG	Technical Review Group
TS	Technical Specification(s)
TSC	Technical Support Center
UHS	ultimate heat sink
USI	unresolved safety issue

SUMMARY

The Systematic Evaluation Program (SEP) was initiated by the U.S. Nuclear Regulatory Commission (NRC) to review the designs of older operating nuclear reactor plants to reconfirm and document their safety. The review provides (1) an assessment of the significance of differences between current technical positions on safety issues and those that existed when a particular plant was licensed, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety Unlike previous SEP reviews, the review of Big Rock Point was expanded to address licensing requirements beyond those evolving from the original program.

The original review compared the as-built plant design with current review criteria in 137 different areas defined as "topics." The "Definition" and other information for the original 137 topics appear in Appendix A. During the review, 52 of the original topics were deleted from consideration by the SEP because a review was being made under other programs (Unresolved Safety Issues (USI) or Three Mile Island (TMI) Action Plan Tasks), or the topic was not applicable to the plant; that is, the topic was applicable to pressurized-water reactors (PWRs) rather than to boiling-water reactors (BWRs). The topics deleted from the original program because they were being reviewed under either the USI or TMI programs are identified in Appendix B. The topics deleted because they did not apply to the plant are in Appendix C. The final version of this report will address the resolution of the SEP topics and any required modifications and will incorporate the views of the Advisory Committee for Reactor Safeguards. A supplement will be issued to address the status of the issues that require further analysis or evaluation.

Of the original 137 topics, 85 were, therefore, reviewed for Big Rock Point; of these, 53 met current criteria or were acceptable on another defined basis. Additionally, two topics were found acceptable as a result of modifications made by the licensee during topic review. Parts of two other topics were also found acceptable as a result of modifications made by the licensee during topic review; other parts of these topics did not meet criteria and were considered in the integrated assessment. It should be noted that there are topics in Section 4 that were resolved before the issuance of the draft Integrated Plant Safety Assessment Report. These topics appear in Section 4 because the staff, in order to expedite the review, determined a cutoff date to make final all topic assessments with deviations. Therefore, all topics that were resolved before January 27, 1983, are presented in Section 3 and all other topics with identified differences as of January 27, 1983, are addressed in Section 4. A description of the modifications that were made during topic review can be found in Section 3.3.

References for correspondence pertaining to safety evaluation reports (SERs) for each of the 85 topics appear in Appendix E. The review of the 30 remaining topics found that certain aspects of plant design differed from current criteria. These topics were considered in the integrated assessment of the plant, which consisted of evaluating the safety significance and other factors

of the identified differences from current design to arrive at decisions on whether modification was necessary from an overall plant safety viewpoint. To arrive at these decisions, judgment was used as well as the results of a limited probabilistic risk assessment (PRA) study. This study and staff comments are in Appendix D.

Table 4.1 summarizes the modification recommendations reached in the integrated assessment. In general, modification requirements fell into one or more of the following categories: (1) equipment modification or addition, (2) procedure development or changes (including Technical Specifications), and (3) refined engineering analysis or continuation of ongoing evaluation, and (4) no corrective actions necessary. Section 5 describes the expanded SEP review that was conducted at the licensee's request. This assessment includes NUREG-0737 items, multiplant action items, unresolved safety issues, and plant-specific items. For each item, the licensee identified the requirements and staff guidance affecting Big Rock Point which he proposes to include in the integrated assessment. The licensee's submittal, dated June 1, 1983, describes those issues for which he proposes alternative resolutions or schedule changes and the safety bases supporting his conclusions relative to his proposal. The licensee's submittal is presented in Appendix H.

The staff compared the licensee's list with the pending actions listed in the Operating Reactors Licensing Actions Summary (ORLAS) book, the USIs that have not yet been resolved generically, and the staff's evaluation of the Big Rock Point PRA in order to ensure that all of the pending issues are addressed. Table 5.1 also identifies the pending actions that were not addressed by the licensee but were evaluated by the staff. Those issues that have not been addressed are either so far along in implementation that any assessment would be moot or they are routine licensing actions that occur regularly.

Safety improvements are being planned as a result of the integrated assessment and are listed below. Some safety improvements have already been implemented by the licensee. The following descriptions summarize the backfit actions addressed by the integrated assessment.

SAFETY IMPROVEMENTS RESULTING FROM THE EXPANDED INTEGRATED ASSESSMENT

These improvements fall into three categories. The first category comprises hardware modifications or additions that the licensee has agreed to make and that are required by the NRC. The second category comprises procedural or Technical Specification changes that become part of the operating license. The third category comprises additional engineering analysis followed by corrective measures where required. These three categories are listed below, and the issues are discussed in sections of this report given in parentheses.

Category 1, Equipment Modifications or Additions Required by NRC

(1) Bypass thermal-overload protection for motor-operated valves under accident conditions (4.15).

(2) Install additional main steam isolation valve (MSIV) position indication as outlined in the licensee's letter dated June 22, 1983 (4.20.5).

(3) Modify MSIV for testing (4.20.7.2).

(4) Cap spare penetrations (4.20.7.4).

(5) Modify diesel generator ventilation system (4.26.2). (Completed)

(6) Modify hotwell level control system (5.3.3.2).

(7) Install debris screens (5.3.6.2).

(8) Install cleanup pump bypass (5.3.9.1).

(9) Install acid pumping system (5.3.9.2).

(10) Replace corroded components in water treatment facility (5.3.9.3).

(11) Add second valve or cap reactor coolant system (RCS) vent and drain lines (5.3.10).

(12) Modify warehouse and training annex to provide more space for qualified equipment storage (5.3.12).

(13) Reroute emergency condenser leads (5.3.14.1).

(14) Provide radiant energy shield for isolation condenser valve cables (5.3.14.2).

(15) Retube heating and cooling heat exchangers (5.3.15).

(16) Modify ventilation for panel C-52 (5.3.16).

(17) Remove RCS high point vents (5.3.26).

(18) Enlarge Technical Support Center (5.4.12).

Category 2, Technical Specification Changes and Procedural Development

The staff's position regarding Technical Specification changes is that the proposed Technical Specification changes may be submitted all together following the completing of the integrated assessment. The licensee should submit within 90 days after the issuance of the Final Integrated Plant Safety Assessment Report a request for an amendment of the operating license to change the facility Technical Specifications.

(1) Provide safe shutdown flood procedures (4.2.4).

(2) Modify operating procedures for operating basis earthquake (4.16).

(3) Provide an inspection program for paints and coatings inside containment (4.19.1).

(4) Provide procedures to identify the conditions under which instrument lines should be isolated (4.20.2).

(5) Develop leak testing and emergency procedures for local manual valves (4.20.4).

(6) Develop MSIV operability test (4.20.5).

(7) Develop air lock seal replacement program (4.20.7.1). (Completed)

(8) Develop leak test for MSIV and main steam line drain valve (4.20.7.2).

(9) Provide a two-tier set of Technical Specification limits on iodine releases (4.28).

(10) Develop procedures for use of high-pressure recycle (5.3.1.2).

(11) Develop emergency operating procedures for the control room and alternate shutdown panel (5.3.2.2).

(12) Install control room air conditioning (5.3.5.3).

(13) Develop stack gas monitoring procedures to use new monitor (5.3.11.1). (Completed)

(14) Place high range monitor into operation (5.3.11.2). (Completed)

(15) Modify Technical Specifications to delete incore detectors and add flux wire system (5.3.13).

(16) Provide electrical casualty procedures (5.3.14.1).

(17) Implement the balance-of-plant quality assurance program (5.3.21).

(18) Modify radwaste monitor (5.3.23).

(19) Define operability and provide limiting conditions of operation for specified systems in the Technical Specifications (5.3.24).

(20) Develop documentation indexing system for Final Hazards Summary Report update requirements (5.3.25.1).

Category 3, Additional Engineering Evaluation

It is the staff's position regarding additional engineering evaluation that all evaluations and corresponding backfits and schedule for backfit implementations be submitted within the established schedules, as documented in the appropriate report sections and summarized in Tables 4.1 and 5.1. These evaluations are as follows:

(1) Determine probable maximum flood evaluation and evaluate adequacy of current procedures (4.2.2). (Completed)

(2) Determine adequacy of usage factors for piping and vessels (4.4).

(3) Demonstrate an ability to achieve safe shutdown using equipment that is protected against tornado missiles (4.8).

(4) Demonstrate an ability to achieve safe shutdown using equipment that is seismically qualified (4.12).

(5) Demonstrate that structures identified in the staff review of Topic III-7.B will not prevent safe shutdown under the specified load combinations (4.13).

(6) Demonstrate that the paint and coatings inside containment are qualified for postaccident conditions and will not clog the recirculation screens (4.19.1).

(7) Evaluate cost/effectiveness of reducing rapid depressurization system (RDS) pilot valve leakage (5.3.1.1).

(8) Evaluate need for full-stroke testing of RDS valves (5.3.1.3).

(9) Evaluate procedural adequacy of alternate shutdown system design (5.3.2.1).

(10) Evaluate control room design (5.3.2.3).

(11) Evaluate turbine bypass valve stability (5.3.3.1).

(12) Evaluate electrical equipment qualification (5.3.4).

(13) Evaluate plant shielding (5.3.5.1). (Completed)

(14) Evaluate control room habitability (5.3.5.2).

(15) Evaluate type and frequency for optimum testing of containment purge and vent valves (5.3.6.2).

(16) Evaluate time sequence of scram valves (5.3.8.1). (Completed)

(17) Determine if redundant scram dump tank valves are necessary (5.3.8.2).

(18) Determine proper and actual air pressure for each air-operated valve (5.3.17).

(19) Evaluate crane modifications (5.3.20).

(20) Determine cause and methods to control pressure transients in reactor cooling water system (5.3.22).

(21) Resolve drawing discrepancies (5.3.25.2).

(22) Evaluate seismic capability of masonry walls (5.4.2).

TOPIC SAFETY EVALUATION REPORTS

Copies of this report and the associated safety evaluation reports for the 85 topics listed in Appendix E are available for public inspection at the NRC Public Document Room, 1717 H Street NW, Washington, DC 20555 and at the Charlevoix Public Library, 107 Clinton Street, Charlevoix, Michigan 49720. Copies of this report are also available for purchase from sources listed on the inside front cover.

This review of the 85 topics was performed by the NRC staff and contractors listed in Appendix G. The Integrated Assessment Team performing the integrated assessment on the 30 topics that did not meet current criteria is as follows:

R. F. Scholl, Jr.--Project Manager, Integrated Assessment, Big Rock Point Plant

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INTEGRATED PLANT SAFETY ASSESSMENT
SYSTEMATIC EVALUATION PROGRAM
BIG ROCK POINT NUCLEAR POWER PLANT

1 INTRODUCTION

1.1 Background

In the late 1960s and early 1970s, the U.S. Atomic Energy Commission's (now Nuclear Regulatory Commission) scope of review of proposed power reactor designs was evolving and somewhat less defined than it is today. The requirements for acceptability evolved as new facilities were reviewed. In 1967, the Commission published for comment and interim use proposed General Design Criteria (GDC) for Nuclear Power Plants that established minimum requirements for the principal design standards. The GDC were formally adopted, though somewhat modified, in 1971, and have been used as guidance in reviewing new plant applications since then. Safety guides issued in 1970 became part of the Regulatory Guide Series in 1972. These guides describe methods acceptable to the staff for implementing specific portions of the regulations, including certain GDC, and formalize staff techniques for performing a facility review. In 1972, the Commission distributed for information and comment a proposed "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," now Regulatory Guide 1.70. It provided a standard format for these reports and identified the principal information needed by the staff for its review. The Standard Review Plan (SRP, NUREG-75/087) was published in December 1975 and updated in July 1981 (NUREG-0800) to provide further guidance for improving the quality and uniformity of staff reviews, to enhance communication and understanding of the review process by interested members of the public and nuclear power industry, and to stabilize the licensing process. For the most part, the detailed acceptance criteria prescribed in the SRP are not new; rather they are methods of review, that, in many cases, were not previously published in any regulatory document.

Because of the evolutionary nature of the licensing requirements discussed above and the developments in technology over the years, operating nuclear power plants embody a broad spectrum of design features and requirements depending on when the plant was constructed, who was the manufacturer, and when the plant was licensed for operation. The amount of documentation that defines these safety-design characteristics also has changed with the age of the plant--the older the plant, the less documentation and potentially the greater the difference from current licensing criteria.

Although the earlier safety evaluations of operating facilities did not address many of the topics discussed in current safety evaluations, all operating facilities have been reviewed more recently against a substantial number of major safety issues that have evolved since the operating license was issued.

Conclusions of overall adequacy with respect to these major issues (e.g.,emergency core cooling system, fuel design, and pressure vessel design) are a matter of record. On the other hand, a number of other issues (e.g., seismic considerations, tornado and turbine missiles, flood protection, pipe break effects inside containment, and piping whip) have not been reviewed against today's acceptance criteria for many operating plants, and documentation for them is incomplete.

1.2 Systematic Evaluation Program Objectives

The Systematic Evaluation Program (SEP) was initiated by the U.S. Nuclear Regulatory Commission (NRC) in 1977 to review the designs of older operating nuclear reactor plants in order to reconfirm and document their safety. The review provides (1) an assessment of the significance of differences between current technical positions on safety issues and those that existed when a particular plant was licensed, (2) a basis for deciding how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

The original SEP objectives were:

(1) The program should establish documentation that shows how the criteria for each operating plant reviewed compare with current criteria on significant safety issues, and should provide a rationale for acceptable departures from these criteria.

(2) The program should provide the capability to make integrated and balanced decisions with respect to any required backfitting.

(3) The program should be structured for early identification and resolution of any significant deficiencies.

(4) The program should assess the safety adequacy of the design and operation of currently licensed nuclear power plants.

(5) The program should use available resources efficiently and minimize requirements for additional resources by NRC or industry.

The program objectives were later interpreted to ensure that the SEP also provides safety assessments adequate for conversion of provisional operating licenses (POLs) to full-term operating licenses (FTOLs). Many of the plants selected for review were licensed before a comprehensive set of licensing criteria had been developed. They include five of the oldest nuclear reactor plants and seven plants under NRC review for the conversion of POLs to FTOLs. The plants to be considered under the original Phase II program were

(1) Yankee Rowe (FTOL PWR)
(2) Haddam Neck (FTOL PWR)
(3) Millstone 1 (POL BWR)
(4) Oyster Creek (POL BWR)
(5) Ginna (POL PWR)
(6) LaCrosse (POL BWR)
(7) Big Rock Point (FTOL BWR)
(8) Palisades (POL PWR)
(9) Dresden 1 (FTOL BWR)
(10) Dresden 2 (FTOL BWR)
(11) San Onofre 1 (POL PWR)

The SEP review of Dresden 1 has been deferred because the plant is undergoing an extensive modification and is not scheduled for restart before June 1986. Therefore, the total number of plants being reviewed for Phase II is 10.

1.3 Description of Plant

The Big Rock Point Nuclear Power Plant site is located in Charlevoix County, between the towns of Charlevoix and Petoskey, on the northern shore of Michigan's lower peninsula. The licensee is Consumers Power Company. As shown schematically in Figure 1.1, the Big Rock Point Nuclear Power Plant consists of a direct cycle, forced circulation boiling-water reactor; a power extraction system; and associated service facilities. The principal structures include a 130-ft-diameter spherical containment vessel, a turbine building, a structure housing water intake facilities, a 240-ft-ventilation stack, and waste storage vaults.

The containment vessel houses the reactor, recirculation piping, pumps, steam drum, fuel pool, and equipment for removal of shutdown heat. The turbine-generator and other conventional plant components are housed in a separate adjoining building.

All components of the reactor and primary coolant system are designed for a system pressure and power of 1,500 psia and 240 thermal megawatts (MWt) (licensed power level), respectively, to enable plant operation up to 75,000-kW gross electrical output. The turbine is a 3,600-rpm, tandem-compound, double-flow, condensing unit directly connected to a hydrogen-cooled generator, which in turn is connected through a reduction gear to an air-cooled exciter. Three points of extraction for feedwater heating are provided.

Two half-capacity, vertical, multistage centrifugal pumps pump the condensate from the hotwell through the condensate system to the suction of the reactor feed pumps. Two feedwater pumps, taking suction directly from the condensate system, discharge feedwater through the high-pressure heater and through a common header to the reactor steam drum. They are horizontal, multistage, centrifugal pumps.

1.4 Summary of Operating History and Experience

The Big Rock Point plant received a provisional operating license on August 30, 1962, and began commercial operation on March 29, 1963. A full-term operating license was issued on May 1, 1964. In May 1964, the licensee increased power from 157 MWt to 240 MWt. Some major modifications made by the licensee since the plant was licensed are as follows. The reactor thermal shields were modified in the period of September 1964 through September 1965. The post-incident cooling system was modified in 1975. A reactor depressurization system was installed in 1976. The reactor coolant inlet diffusers and a leak in a control rod drive housing were repaired in 1979.

1.4.1 Summary of Oak Ridge National Laboratory Report

1.4.1.1 Introduction

To ensure that the plant's operating history, including plant transients, was appropriately evaluated and factored into the NRC staff evaluation, the staff requested the Oak Ridge National Laboratory (ORNL) to perform a detailed review. A copy of the ORNL report is attached as Appendix F. The licensee commented on a draft version of this report in a letter dated January 14, 1983(a). Some of these comments are reflected in the final version; however, the remaining comments reflect differences in judgment or interpretation. The staff does not believe that these differences affect the conclusions drawn in this evaluation.

Table 1.1 presents the Big Rock Point reactor availability and plant capacity factors. Values range from a low in 1975, when the unit was shut down for part of the year for thermal shield modifications, to a high during 1971, when the reactor was shut down only 18 days throughout the entire year.

From 1962 to 1981, Big Rock Point has experienced 124 forced shutdowns and 69 forced power reductions. In reviewing the forced shutdowns and power reductions, one is examining events during which the plant was forced to shut down or to reduce power as a result of some abnormal condition. Some abnormal conditions that resulted in a forced shutdown are identifiable as initiating events of design-basis-event (DBE) accident scenarios. These events can be associated with 21 of the 124 forced shutdowns. (See Table 4.4 in Appendix F for events occurring through 1981.)

Oak Ridge National Laboratory reviewed licensee event reports for Big Rock Point* and, at the time of review, approximately 366 individual events were evaluated. Human error and procedural inadequacies have caused or at least complicated 46% of all reportable events at Big Rock Point. Human errors include administrative, design, installation, maintenance, and operator errors.

1.4.1.2 Forced Shutdowns and Power Reductions

The primary objective of the review of the operating experience at Big Rock Point was to identify any substantial performance of safety systems. The two criteria for this evaluation were

(1) events that subjected the plant to a DBE-initiating condition

(2) events that caused a loss of a safety function designed to mitigate the effects of the DBEs.

In all cases of DBE shutdowns (21 events), the events did not initiate any sequence that resulted in a safety hazard to the plant or environs.

The DBE with the highest frequency (9 events) was loss of external load. Only three of these events resulted in a complete loss of offsite power with two occurring before the installation of a 46-kV transmission line in 1968. Each of these events was caused by equipment failure or a storm. The other six losses of external loads were partial losses. In each event, the 138-kV transmission line was isolated from the plant. The causes of these six events were electrical storms (3), human errors (2), and relay malfunctions (1). The complete losses occurred in 1965, 1966, and 1972. The partial losses of

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*Referenced in Appendix A of the ORNL report, Tables A1.1 through A2.11 (see Appendix F of this report).

power occurred during two different periods: June 1970 to September 1971 (4) and April 1978 to May 1978 (2). The remaining 12 DBE-related forced shutdowns and power reductions were caused by

(1) steam pressure regulator malfunction resulting in decreased steam flow (3)
(2) turbine trip (3)
(3) reactor coolant pump trip (2)
(4) control rod maloperation (2)
(5) loss of normal feedwater flow (1)
(6) loss of condenser vacuum (1)

Equipment failures caused 10 of the DBEs; human errors accounted for 7. Electrical storms caused an additional four DBEs when the 138-kV transmission line was lost. All four storms occurred between 1966 and 1971. Sixteen of the DBEs occurred between 1962 and 1972. After 1972, the frequency of DBEs decreased significantly with equipment failures causing four DBEs and human errors causing one.

1.4.1.3 Reportable Events

In the reportable event segment of the operating review of Big Rock Point, 366 events were reviewed. Until 1974, Big Rock Point had reported an average of seven events per year. The peak year for reportable events occurred in 1977, when Big Rock Point filed reports on 50 events. Since 1974, the average number of reportable events has increased to 39. The primary cause of reportable events has been inherent equipment failure, which contributed to 52% of all events. Human errors (including administrative, design, fabrication, installation, maintenance, and operator error) caused 46% of the reportable events. Other causes, such as lightning, were responsible for 1%. For the remaining 1% of reportable events, no causes were reported. No trends in the causes of reported events were identified.

Of the 366 reported events, 6 were identified as significant:

(1) loss of offsite power (2)

(2) containment integrity violated (1)

(3) both fire pumps unavailable while automatic depressurization system (ADS) was unavailable (1)

(4) failure of two reactor protection system (RPS) channels while 138-kV line was unavailable (1)

(5) recirculation diffusers break off (1)

Inherent failures, human errors, and the weather each caused two events. No trend was observed in the frequency of significant events, and no major problems in terms of plant safety were identified.

1.4.1.4 Recurring Events

The following three types of recurring events were noted during the review of Big Rock Point's operating history:

(1) control rod drive problems
(2) failed fuel elements
(3) failures involving the emergency condenser

Many of the difficulties encountered with the control rod drives and fuel elements were limited to the earlier years of operation. Recurring problems involved the control rods drifting out of the core, galling of the control rod index tubes, jamming of the rods so that they could be inserted but not withdrawn, and withdrawal times less than the Technical Specifications limit. The first three types of problems have not occurred since 1968. The last time a control rod's withdrawal time was less than the limit was 1978.

Big Rock Point is a high-power density reactor that has been involved in developmental programs to test high-performance fuel elements. It was during these developmental programs that fuel cladding failures occurred. The fuel cladding failures did not pose any safety problems because power reductions kept the off-gas activity within acceptable limits.

Eleven events involved failures with the emergency condenser. Two of the failures rendered one of the two emergency condenser loops inoperable in 1973 and 1978. However, a single tube bundle is sufficient to remove decay heat.

1.4.2 Operating Experience, January 1, 1982, Through February 28, 1983

The unit operated from January 1, 1982, through February 28, 1983, and experienced three reactor trips, one reactor shutdown, one removal of the main generator from the grid, and one refueling outage. Gross electrical generation was restricted during this period to approximately 65 megawatts-electric (MWe) because of thermal margin considerations. Capacity and service factors computed for the year 1982 are 63.2% and 70.8%, respectively. Capacity and service factors computed through February 1983 are 92.8% and 100%, respectively. Cumulative capacity and service factors for the life of the unit are 57.4% and 69%, respectively. Three reactor trips occurred on January 7, June 11, and December 7, 1982. The first was a manual scram caused by a faulty reactor protection system reset switch, which led to several control rods drifting into the core. The second trip was a manual scram necessitated by a fire in the exciter housing of the main generator. The third trip was an automatic scram brought on by a broken terminal board that caused a false turbine stop valve closed signal to be sent to the generator output breaker which resulted in a turbine load rejection and subsequent reactor trip.

Significant facility modifications performed during the last refueling outage included (1) addition of a water makeup line to the spent fuel pool; (2) upgrading of the containment pressure monitoring instrumentation; (3) modification of the secondary water supply to the emergency condenser, permitting remote actuation; and (4) modification of the containment spray system piping and control system.

1.4.3 Regulatory Performance, January 3, 1982, Through February 28, 1983

A management meeting was held with the licensee on October 28, 1982, to discuss the findings of the NRC Systematic Assessment of Licensee Performance (SALP), which was conducted in accordance with NRC Manual Chapter 0516. The review included the licensee's performance with the objective of improving regulatory programs and performance and was based on activities from July 1, 1981, through June 30, 1982. The SALP Board concluded that the licensee's operational and regulatory performance was generally acceptable and directed toward safe operation. The SALP Board's conclusions for each of the 11 functional areas were categorized as follows:

Category 1

Reduced NRC attention may be appropriate. The attention and involvement of the licensee's management are aggressive and oriented toward nuclear safety; the licensee's resources are adequate and are reasonably effective so that satisfactory performance with respect to operational safety or construction is being achieved.

Category 2

NRC attention should be maintained at normal levels. The attention and involvement of the licensee's management are evident and are directed toward nuclear safety; the licensee's resources are adequate and are reasonably effective so that satisfactory performance with respect to operational safety and construction is being achieved.

Category 3

Both NRC and licensee attention should be increased. The attention and involvement of the licensee's management are acceptable and are directed toward nuclear safety, but weaknesses are evident; the licensee's resources appear strained or not effectively used so that minimally satisfactory performance with respect to operational safety and construction is being achieved.

The following functional areas were evaluated:

(1) plant operations
(2) radiological controls
(3) maintenance
(4) surveillance
(5) fire protection and housekeeping
(6) emergency preparedness
(7) security and safeguards
(8) refueling operations
(9) licensing activities
(10 training
(11) environmental protection and confirmatory measurements

The SALP Board ranked the licensee's performance as Category 1 in three areas, Category 2 in six areas, and Category 3 in two areas, namely, radiological controls and training. The SALP Board concluded that the licensee's performance during the period remained satisfactory.

Thirty-five events were reported through February 28, 1983, by the licensee event report system. Of these, 21 were due to component failure, 3 to design, 2 to defective procedures, and 5 to personnel error.

1.4.4 Regulatory Performance, March 1, 1983, Through March 31, 1984

The performance during this period of operation was not significantly different from previous experience in most respects. The most notable changes were:

(1) upgrading from Category 3 to Category 2 in the areas of radiological controls and training as noted in the SALP report for the period of July 1, 1982, through June 30, 1983

(2) completion of testimony for the spent fuel pool capacity expansion

(3) completion of a major refueling outage with 10-year inservice inspection

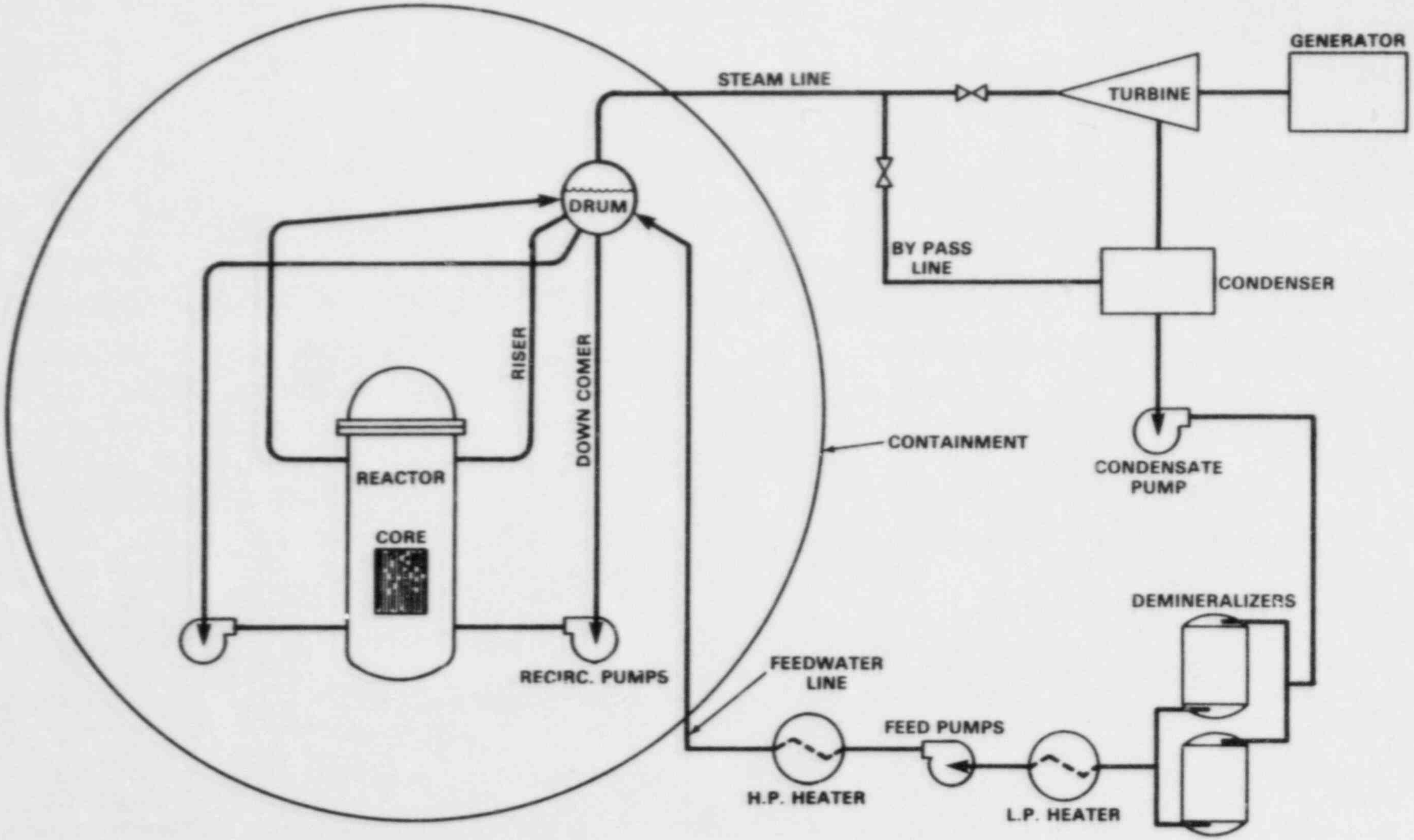

Figure 1.1 Schematic diagram of Big Rock Point

Table 1.1 Availability and capacity factors for Big Rock Point

Average	1962-63	1964	1965[a]	1966[a]	1967[a]	1968[a]	1969[a]	1970[a]	1971	1972
Reactor availability	c	c	14.8	75.1	83.7	81.5	89.7	93.5	96.7	80.0
Unit availability	c	c	14.6	73.6	81.8	80.2	c	c	c	79.9
Unit capacity (MDC)[d]	c	c	13.2	60.5	75.7	68.8	67.3	64.6	59.3	70.7
Unit capacity (DER)[e]	c	c	13.0	59.7	74.6	67.8	66.4	63.7	58.5	69.7

Average	1973	1974	1975	1976	1977	1978	1979	1980	1981	Cumulative
Reactor availability	80.0	70.8	60.3	51.4	74.1	78.9	24.0	79.2	91.4	70.0
Unit availability	79.9	70.3	59.8	50.1	73.4	77.9	23.5	78.9	90.6	68.6
Unit capacity (MDC)[c]	67.9	54.3	46.7	39.2	63.4	71.9	20.6	71.5	83.6	56.8
Unit capacity (DER)[e]	67.0	53.5	46.1	38.7	57.2	63.6	18.0	64.1	74.5	53.2

[a] November to November

[b] November 1979 to December 1970

[c] No data (ND)

[d] MDC = maximum dependable capacity

[e] DER = design electrical rating

Source: Oak Ridge National Laboratory Report (see Appendix F of this report).

2 REVIEW METHOD

2.1 Overview

The Systematic Evaluation Program (SEP) review procedure represents a departure from the typical NRC staff reviews conducted to support the granting of a construction permit or operating license for a new facility or a license amendment for an operating facility. A typical licensing review starts with the submittal by the utility of a safety analysis report (SAR) that describes the design of the proposed plant. The staff reviews the SAR on the basis of the Standard Review Plan (SRP), regulatory guides, and branch technical positions that constitute current licensing criteria. The guidelines in the SRP represent acceptable means of complying with licensing regulations specified in Title 10 of the Code of Federal Regulations (10 CFR).

The SEP was initiated by NRC, and not by the licensee as part of an application for a license or request for a license amendment. The SEP procedure involves several phases of data gathering and evaluation so that an integrated assessment of the overall plant safety can be made. The various phases and their interrelationships are described below.

2.2 Selection of Topic List

A list of significant safety topics was derived from existing safety issues during Phase I of the program. More than 800 items were considered in the development of the original list; however, a number of these were found to be duplicative in nature or were deleted for other reasons. Categories of topics that were deleted for other reasons are (1) those not normally included in the review of light-water reactors, (2) those related either to research-and-development programs or to the development of analytical evaluation models and methodology, and (3) those that are reviewed on a periodic basis in accordance with current criteria (e.g., fuel performance). The topics retained numbered 137; these were arranged in groups corresponding to the organization of the SRP. A "definition" was prepared for each topic to ensure a common understanding. This definition plus a statement of the safety objective for the review and the status of the review at that time is contained in Appendix A for ease of reference.

During the course of this review, the number of topics that applied to all plants was reduced further because some topics were being reviewed generically under either the Unresolved Safety Issues (USIs) program or the Three Mile Island (TMI) NRC Action Plan; also, duplicates found within the SEP topics were deleted. Appendix B shows these topics along with the corresponding USI, TMI task, or SEP topic referenced. The basis for deletion appears in Appendix A under individual topics.

Plant-specific deletions other than those common to all SEP plants were made to account for nonapplicability of particular topics to Big Rock Point. The plant-specific topics that were removed for Big Rock Point and the bases for deletion are shown in Appendix C.

For Big Rock Point, this process resulted in 85 topics from the topic list that formed the SEP review. The final list of 85 topics that were reviewed for Big Rock Point appears in Section 3.1.

The milestones in the review of the SEP program and the Big Rock Point Plant are shown in Table 2.1.

2.3 Topic Evaluation Procedures

Each SEP topic in Section 3.1 was reviewed to determine whether the corresponding plant design was consistent with current licensing criteria such as regulations, guides, and SRP review criteria, or the equivalent of such criteria. Safety evaluation reports (SERs) for all 85 topics were issued to document the comparison with current licensing criteria and to identify potential areas for modification. References for letters regarding the individual topic SERs are contained in Appendix E. These documents describe the detailed evaluations where conclusions are summarized in this report.

Topics were evaluated by one of two methods:

(1) The NRC staff reviewed and formally issued an SER to the licensee. This SER was termed a draft because it was only one input element to the evaluation. The purpose of the draft SER was to verify the factual accuracy of the described facility and to allow the licensee to identify possible alternate approaches to meeting the current licensing criteria. After a review of the licensee's comments on the draft SER, factual changes were incorporated as needed, proposed alternatives were reviewed, and the SER was issued in final form.

(2) The licensee submitted an SAR, and the staff issued a final SER based on a review of this submittal.

After completion of the topic evaluation, the disposition of each topic was grouped according to one of the following results:

(1) The plant is consistent with current licensing criteria and the topic review is considered complete. If the plant does not meet current licensing criteria, but the present design is equivalent to current criteria, the topic is also considered complete. A justification for this conclusion is provided in the topic SER. The topics in this category are identified in Section 3.1 of this report by an asterisk.

(2) The plant is not consistent with current licensing criteria, but the licensee has implemented or proposed design or procedural changes that the staff finds acceptable. A summary of the topic evaluation and the corrective actions taken in this category appear in Section 3.3.

(3) The plant is not consistent with current licensing criteria, and the differences from these criteria are to be evaluated as potential candidates for modification. If the staff determines the difference is of immediate safety significance, action is taken to resolve the issue promptly. No issues at Big Rock Point required that prompt

action be taken. If the difference is not of immediate safety significance, the resolution is deferred to the integrated plant safety assessment to obtain maximum benefit from coordinated and integrated modification decisions. The SEP evaluation of all 85 topics led to the conclusion that 34 topics were not consistent with current criteria. Of these, 2 topics were resolved during the topic review and are addressed in Section 3, and 32 were considered in the integrated safety assessment and appear in Section 4. The licensee has proposed integration of some modifications proposed during the topic review with modifications resulting from the integrated assessment.

2.4 Integrated Plant Safety Assessment

The objective of the integrated plant safety assessment is to make balanced and integrated decisions on implementing current licensing criteria to SEP facilities. Factors considered important in reaching decisions on implementation include safety significance, radiation exposure to workers, and, to a lesser extent, implementation impact and schedule.

A meeting was held with the licensee (Consumers Power Company) to discuss these factors as they related to the differences identified during the SEP review between actual facility design and current licensing criteria and to obtain the licensee's views on safety significance and possible corrective actions.

The licensee by letter dated February 28, 1983, proposed corrective actions for most of the identified differences. Subsequently, in a letter dated March 18, 1983, the licensee requested that the scope of issues to be addressed in the integrated assessment be expanded to include many of the pending licensing actions for Big Rock Point which had evolved from staff reviews outside the scope of SEP. These additional issues included many of the TMI Action Plan requirements and USI implementation criteria that were excluded from the SEP scope of review. These issues also included other generic implementation criteria (e.g., multiplant actions) and utility-sponsored plant improvements.

The purpose of the expanded scope of issues is to develop a "living schedule" of plant improvements and ongoing engineering analyses to provide the most efficient use of the licensee's resources. The licensee, by letter dated June 1, 1983, identified specific issues to be considered in the integrated assessment and presented the results of their integrated assessment review of these issues. The licensee's integrated assessment was conducted by a Technical Review Group (TRG) using experience and insights gained from the utility-sponsored probabilistic risk assessment as described in Section 5.2.

Because the staff's decisions in the integrated assessment sometimes rely on judgment, risk assessment techniques were similarly used to the extent possible to supplement the staff's judgments concerning the safety significance of a particular issue. A limited probabilistic risk assessment (PRA), performed by Science Applications, Inc. (SAI) for the staff, was based on a plant-specific PRA performed by the licensee. The limited PRA, along with comments by the staff, appears in Appendix D. For reasons given in Appendix D, only certain topics could be readily analyzed by a PRA. The staff used risk assessment techniques for evaluating selected SEP topics as well as the additional issues described in Section 5, including NUREG-0737 and multiplant action items. The risk reduction potential (expressed as societal dose reduction) was calculated for the proposed resolution of Section 4 and Section 5 topics. The risk reduction potential was then considered along with implementation costs to provide an input for the resolution of issues pertaining to Big Rock Point.

Although the staff's integrated assessment considered all of the issues collectively, the results are presented in two parts for clarity. Section 4 presents the issues that evolved from the SEP topic reviews, as described in Sections 2.3 and 3. Section 5 presents the non-SEP issues, that is, the pending licensing actions and utility-sponsored plant improvements that constitute the expanded scope of the integrated assessment.

The staff's findings presented in the draft integrated assessment were discussed with the Advisory Committee on Reactor Safeguards in November 1983. The Committee's comments and the staff's response to those comments appear in Appendix I.

The draft integrated assessment was issued in September 1983. To provide an additional level of perspective to the staff's findings, the draft integrated assessment was reviewed by five independent consultants. The consultants' comments, and the staff's response to the comments, appear in Appendix J.

Inasmuch as a number of the projects were ongoing at the time that this report was issued in draft form, a number of these projects have subsequently been completed. This final version identifies the schedules for all the remaining projects, which constitute the foundation for the licensee's integrated implementation schedule. The final results of the integrated assessment are based on commitments and implementation schedules proposed by the licensee in letters dated February 2, 1984, and May 2, 1984.

Table 2.1 Topic list selection and resolution

ORIGINAL PHASE I TOPIC LIST
800

Many of these topics were deleted because they were duplicative in nature, were not normally included in the review of light-water reactors, were related to research-and-development programs, or were reviewed on a periodic basis in accordance with current criteria.

FINAL LIST OF PHASE I TOPICS REVIEWED DURING PHASE II
137 (see Appendix A)

Of the 137 topics, 23 were deleted because they were being reviewed generically under either the Unresolved Safety Issues (USIs) program or the Three Mile Island (TMI) NRC Action Plan (see Appendix B).

REMAINING TOPICS AFTER DELETION OF USIs AND TMI-RELATED TOPICS
114

Of the remaining 114 topics, 29 were deleted because the topics did not apply to Big Rock Point (see Appendix C).

FINAL NUMBER OF TOPICS REVIEWED FOR BIG ROCK POINT
85 (see Section 3.1 and Appendix E)

TOPICS THAT MET CURRENT CRITERIA OR WERE
ACCEPTABLE ON ANOTHER DEFINED BASIS
53 (see Section 3.2)

TOPICS THAT MET CURRENT CRITERIA OR WERE ACCEPTABLE ON ANOTHER
DEFINED BASIS AFTER MODIFICATIONS MADE DURING TOPIC REVIEW
2 (see Section 3.3)

TOPICS CONSIDERED FOR BACKFIT IN THE INTEGRATED ASSESSMENT
30 (see Table 4.1 and Sections 4.1-4.28)

3 SEP TOPIC EVALUATION SUMMARY

3.1 Final Big Rock Point-Specific List of 85 Topics Reviewed

Listed below are the 85 topics that were reviewed for Big Rock Point. The topics with asterisks are those for which the plant meets current criteria or was acceptable on another defined basis:

TOPIC	TITLE
II-1.A*	Exclusion Area Authority and Control
II-1.B*	Population Distribution
II-1.C*	Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities
II-2.A	Severe Weather Phenomena
II-2.C*	Atmospheric Transport and Diffusion Characteristics for Accident Analysis
II-3.A*	Hydrologic Description
II-3.B	Flooding Potential and Protection Requirements
II-3.B.1	Capability of Operating Plant To Cope With Design-Basis Flooding Conditions
II-3.C	Safety-Related Water Supply (Ultimate Heat Sink [UHS])
II-4*	Geology and Seismology
II-4.A*	Tectonic Province
II-4.B	Proximity of Capable Tectonic Structures in Plant Vicinity
II-4.C*	Historical Seismicity Within 200 Miles of Plant
II-4.D*	Stability of Slopes
II-4.F*	Settlement of Foundations and Buried Equipment
III-1	Classification of Structures, Systems and Components (Seismic and Quality)
III-2	Wind and Tornado Loadings
III-3.A	Effects of High Water Level on Structures
III-3.C	Inservice Inspection of Water Control Structures
III-4.A	Tornado Missiles
III-4.B	Turbine Missiles
III-4.C*	Internally Generated Missiles
III-4.D*	Site-Proximity Missiles (Including Aircraft)
III-5.A	Effects of Pipe Break on Structures, Systems and Components
III-5.B	Pipe Break Outside Containment
III-6	Seismic Design Considerations
III-7.B	Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria
III-7.D*	Containment Structural Integrity Tests
III-8.A	Loose-Parts Monitoring and Core Barrel Vibration Monitoring
III-8.C*	Irradiation Damage, Use of Sensitized Stainless Steel, and Fatigue Resistance
III-10.A	Thermal-Overload Protection for Motors of Motor-Operated Valves
IV-1.A*	Operation With Less Than All Loops in Service

TOPIC	TITLE
IV-2*	Reactivity Control Systems Including Functional Design and Protection Against Single Failures
V-4*	Piping and Safe-End Integrity
V-5	Reactor Coolant Pressure Boundary (RCPB) Leakage Detection
V-6*	Reactor Vessel Integrity
V-10.A	Residual Heat Removal System Heat Exchanger Tube Failures
V-10.B*	Residual Heat Removal System Reliability
V-11.A*	Requirements for Isolation of High- and Low-Pressure Systems
V-11.B*	Residual Heat Removal System Interlock Requirements
V-12.A	Water Purity of BWR Primary Coolant
VI-1	Organic Materials and Postaccident Chemistry
VI-2.D*	Mass and Energy Release for Postulated Pipe Break Inside Containment
VI-3*	Containment Pressure and Heat Removal Capability
VI-4	Containment Isolation System
VI-6*	Containment Leak Testing
VI-7.A.3*	Emergency Core Cooling System Actuation System
VI-7.A.4*	Core Spray Nozzle Effectiveness
VI-7.B*	Engineered Safety Feature Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)
VI-7.C*	Emergency Core Cooling System (ECCS) Single-Failure Criterion and Requirements for Locking Out Power to Valves, Including Independence of Interlocks on ECCS Valves
VI-7.C.1*	Appendix K--Electrical Instrumentation and Control Re-reviews
VI-7.C.2*	Failure Mode Analysis (Emergency Core Cooling System)
VI-7.D*	Long-Term Cooling Passive Failures (e.g., Flooding of Redundant Components)
VI-10.A	Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing
VII-1.A	Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices
VII-1.B*	Trip Uncertainty and Setpoint Analysis Review of Operating Data Base
VII-2*	Engineered Safety Features System Control Logic and Design
VII-3*	Systems Required for Safe Shutdown
VII-6*	Frequency Decay
VIII-1.A*	Potential Equipment Failures Associated With Degraded Grid Voltage
VIII-2*	Onsite Emergency Power Systems (Diesel Generator)
VIII-3.A*	Station Battery Capacity Test Requirements
VIII-3.B	DC Power System Bus Voltage Monitoring and Annunciation
VIII-4	Electrical Penetrations of Reactor Containment
IX-1*	Fuel Storage
IX-3	Station Service and Cooling Water Systems
IX-5	Ventilation Systems
IX-6*	Fire Protection
XIII-2*	Safeguards/Industrial Security
XV-1*	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

TOPIC	TITLE
XV-3*	Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)
XV-4*	Loss of Nonemergency AC Power to the Station Auxiliaries
XV-5*	Loss of Normal Feedwater Flow
XV-7*	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break
XV-8	Control Rod Misoperation (System Malfunction or Operator Error)
XV-9*	Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate
XV-11*	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (BWR)
XV-13*	Spectrum of Rod Drop Accident (BWR)
XV-14*	Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction That Increases Reator Coolant Inventory
XV-15*	Inadvertent Opening of a PWR Pressurizer Safety/Relief Valve or a BWR Safety/Relief Valve
XV-16*	Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment
XV-18	Radiological Consequences of Main Steam Line Failure Outside Containment
XV-19*	Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary
XV-20*	Radiological Consequences of Fuel-Damaging Accidents (Inside and Outside Containment)
XVII*	Operational Quality Assurance Program[1]

3.2 Topics for Which Plant Design Meets Current Criteria or Was Acceptable on Another Defined Basis

As listed in Section 3.1.

3.3 Topics for Which Plant Design Meets Current Criteria or Equivalent Based on Modifications Implemented by the Licensee

This section summarizes those topics (II-1.A and IV-1.A) that meet current criteria as a result of modifications made or committed to by the licensee during topic review. (These topics are also listed in Section 3.1 because they now meet current criteria.)

[1]The Operational Quality Assurance Program was reviewed according to the criteria specified for operating reactors in 1974 (see Appendix A). NRC is currently evaluating all aspects of Nuclear Power Plant Quality Assurance Programs. Additional review of this issue will be performed outside the context of SEP.

3.3.1 Topic II-1.A, Exclusion Area Authority and Control

The safety objective of this topic is to ensure that appropriate exclusion area authority and control are maintained by the licensee as required by 10 CFR 100. The review was conducted in accordance with the guidance given in SRP Section 2.1.2. The staff concluded that the licensee did not have control of traffic on the Chesapeake and Ohio Railroad line which traverses a part of the exclusion area.

The licensee subsequently modified the emergency plan so that the Sheriff will have adequate control over rail traffic on this line during an emergency.

3.3.2 Topic IV-1.A, Operation With Less Than All Loops in Service

The safety objective of this topic is to ensure that flow through an inactive loop does not interfere with safety instrumentation or cause core flow asymmetries that invalidate the models upon which the ECCS designs are based.

The licensee provided sufficient analysis to permit the issuance of Amendment 48 to Facility Operating License DPR-6.

4 INTEGRATED ASSESSMENT SUMMARY

Table 4.1 shows the list of topics considered in the integrated assessment, whether Technical Specification requirements or modifications are needed, and whether or not the licensee proposes to modify Big Rock Point. A more detailed description of each topic with identified differences follows.

Implementation schedules have not been completed by the licensee. This is consistent with the current status of the staff's integrated assessment review. The licensee will be requested to complete implementation schedules for all plant modifications and procedure revisions following review by the Advisory Committee on Reactor Safeguards (ACRS) of this draft Integrated Plant Safety Assessment Report (IPSAR). Final implementation schedules will be developed by the licensee within 90 days of the publication of this report and will be identified in the supplement. The differences from current licensing criteria identified in this section were derived from the safety evaluation reports referenced in Appendix E.

A limited probabilistic risk assessment (PRA) has been performed for 14 of the SEP topics with identified differences from current licensing criteria. This limited PRA is presented in Appendix D and is based on a plant-specific PRA study performed by the licensee. This risk perspective has been used to judge the importance of the identified differences in relation to accident sequences leading to core melt, with due consideration of the uncertainties in the PRA techniques. In addition, the licensee has performed his own integrated assessment, submitted by a letter dated February 28, 1983, and has proposed corrective actions to resolve those issues considered significant.

The licensee's submittal and the limited risk assessment have been evaluated by the staff and used as input to this integrated plant safety assessment. Where the licensee's proposed corrective actions are consistent with or equivalent to current licensing criteria, they constitute the basis for the staff's acceptance. The remaining issues were evaluated using the process described in Section 2.4.

4.1 Topic II-2.A, Severe Weather Phenomena

The topic evaluation identified wind and tornado loading conditions that had not been considered in the original plant design. These conditions are addressed in relation to Topics III-2 and III-4.A for wind and tornado loadings and tornado missiles in Sections 4.5 and 4.8, respectively.

4.2 Topic II-3.B, Flooding Potential and Protection Requirements; Topic II-3.B.1, Capability of Operating Plants To Cope With Design-Basis Flooding Conditions; and Topic II-3.C, Safety-Related Water Supply (Ultimate Heat Sink [UHS])

10 CFR 50 (GDC 2), as implemented by SRP Sections 2.4.2, 2.4.5, 2.4.10, 2.4.11, and 3.4.1 and Regulatory Guides 1.27 and 1.59, requires that structures, systems, and components important to safety be designed to withstand the effects

of natural phenomena such as flooding. The safety objective of these topics (II-3.B, II-3.B.1, and II-3.C) is to verify that adequate operating procedures and/or system designs are provided to cope with the design-basis flood.

The site grade elevation is 583.5 to 594 ft mean sea level (MSL). During the staff's review of the hydrology-related topics, the following flooding elevations were identified, as defined by current licensing criteria:

probable maximum flood (PMF) resulting from:
probable maximum precipitation (PMP) - 598.8 ft MSL
probable maximum surge (PMS) from wave runup - 586.8 ft MSL

As a result of these flooding levels, the staff has identified the following issues.

4.2.1 Design-Basis Ground Water Level

The original design value for ground water level at Big Rock Point was 583.6 ft MSL. In lieu of an analysis to determine the maximum ground water level, a ground water level at plant grade should be assumed when considering uplift and hydrostatic forces separately from seismic loadings. The staff's review of this topic indicates that plant structures can withstand ground water levels at plant grade, and, therefore, this issue is resolved to the staff's satisfaction.

In lieu of further analysis to determine the ground water level to be used in combination with seismic loading, the highest recorded lake level (approximately 584 ft MSL) may be used. As part of the SEP Topic III-6 evaluation, load combinations involving seismic loading and ground water level were considered using the original design-basis ground water elevation of 583.0 ft MSL. This elevation is sufficiently close to the 584-ft value so that the staff finds it acceptable. The adequacy of structures to resist the seismic-groundwater load combination is being reviewed in SEP Topic III-6. Other load combinations are being addressed in SEP Topic III-7.B.

4.2.2 Probable Maximum Flood

The topic evaluation estimated that the PMF resulting from the PMP in the drainage basin around the plant site would result in flooding elevations of 598.8 ft MSL at the west side of the turbine building. Further, a storm surge from Lake Michigan was estimated to result in a flooding elevation of 586.8 ft MSL at the intake structure. These various flooding estimates were derived from conservative analyses of the flooding events performed by consultants to the staff.

By letter dated June 23, 1983, the licensee transmitted the results of a flooding analysis of the site, which concluded that the maximum flood elevation would be slightly below 594.0 ft MSL at the turbine building for the PMP and PMF and 587.4 ft MSL for lake flooding. The licensee's evaluation of lake flooding included wave runup effects for a fast moving squall in conjunction with the maximum mean monthly lake level.

Safe shutdown can be accomplished for flooding events in which the flooding elevation does not exceed about 594.0 ft MSL at the turbine building and about 589.0 ft MSL outside and about 584.0 ft MSL inside the intake structure. At these elevations, the interior of the structures would be flooded, but the pumps and electric power supplies necessary for shutdown would be above the flooding elevation. Further, if cooling water could not be supplied by the pumps inside the intake structures, the emergency condenser could operate using the demineralized water storage tank with well-water cooling for control valves.

To resolve this issue, the staff reviewed detailed hydrologic engineering calculations, maps, level surveys, photographs of critical site features, and a report by a licensee consultant on Lake Michigan flooding effects. On the basis of an analysis of this additional information, the staff concludes that a PMF caused by either PMP or lake flooding would not exceed 594.0 ft MSL at the turbine building or 584.1 ft MSL inside the intake structure. In view of this finding and the extreme nature of the assumptions regarding a PMF event, the staff concludes that the plant can safely shut down in the event of a probable maximum flood.

4.2.3 Probable Minimum Water Level

The topic evaluation identified a probable minimum lake water level that could potentially cause a loss of the cooling path to the ultimate heat sink.

The licensee has evaluated the cooling capability of the plant under such conditions. The licensee's evaluation concluded that the minimum water elevation resulting from a negative lake surge or seiche would be 572.1 ft MSL with the circulating pumps, service water pumps, and fire pumps all operating. This elevation is above the stated minimum elevation of 570.0 ft MSL necessary to maintain the minimum required net positive suction head for these pumps.

The staff has reviewed the licensee's analyses and concludes that the probable minimum water elevation will exceed the required 570.0 ft MSL. Therefore, this issue is resolved.

4.2.4 Flood Emergency Plan

The topic evaluation concluded that the licensee's flood emergency plan in its present form does not meet current criteria regarding its adequacy for safe shutdown of the facility following a severe flood. Further, there is no existing Technical Specification (TS) limit that restricts plant operation for a flooding event.

In a letter dated February 2, 1984, the licensee committed to develop an emergency procedure that would instruct the operators to contact a local fire department to request a pumper truck to refill the demineralized water storage tank in the event the demineralized water transfer pump, demineralized water fill pump, and fire pumps are disabled by the flooding events as described in Sections 4.2.2 and 4.11.

The demineralized water storage tank can supply cooling water to the emergency condenser for approximately 8 hours, which allows sufficient time to implement such a procedure.

This new emergency procedure will be completed by November 1984. The staff will confirm that this procedure identifies the appropriate corrective actions to transfer functions and electrical loads to equipment located above the maximum flooding elevation well before that equipment would be disabled by flooding.

4.3 Topic II-4.B, Proximity of Capable Tectonic Structures in Plant Vicinity

10 CFR 100, as implemented by SRP Sections 2.5.1 and 2.5.3, requires that the site be reviewed with respect to local geological features that may lead to earthquake faulting (resulting in ground motion) and caverns that may lead to collapse. When the staff first considered the possibility of solution features (caverns) beneath the site two concerns came to light:

(1) the possible existence of a large cavern under the site that could ultimately cause subsidence or collapse

(2) the possibility of the development and enlargement of a new cavern during the life of the plant

These concerns arose after a review of the literature and a site visit by an NRC geologist. In their report, "Solution Features in the Traverse Group of Northwestern Michigan," Harding-Lawson Associates, geology consultants for Consumers Power Company, presented data supporting their conclusion that extensive solutioning is not going on in the site area at the present time, nor has it likely been for the past several thousand years. The evidence cited includes:

(1) The sinks present in the quarries are filled with undisturbed glacial deposits including sand, gravel, and till, thus dating the solution holes as being at least Late Pleistocene age.

(2) The open cavern in the Penn-Dixie quarry had been bridged by 60 to 80 ft of rock before excavation and was well below the present level of Lake Michigan, indicating that it probably formed when the level of the lake was much lower than it is today.

(3) Movement of ground water through the rock, related to the wide range of fluctuation of the surface of ancestral Lake Michigan during the Pleistocene age, is believed to have caused most of the more geologically recent solutioning activity. The level of Lake Michigan and the local ground water surface have been relatively stable since the lake reached its present level after the close of the Pleistocene age.

(4) The site region is covered by a blanket of relatively impermeable soil, causing most precipitation to run off rather than percolate down and move through the rock.

(5) Extensive karst topography is not apparent at ground surface in the site area. However, because of the scarcity of information on the condition of site bedrock, the topic evaluation recommended that the licensee perform additional studies to confirm bedrock competency.

The licensee contracted with Commonwealth Associates, Inc. (CAI) of Jackson, Michigan, to investigate the possible existence of solution cavities beneath the plant. CAI reported its conclusions in the report "An Investigation Into the Possible Existence of Solution Cavities Beneath the Big Rock Point Nuclear Power Plant Near Charlevoix, Michigan," February 1983. In that report the consultant concluded that the geologic processes that created solution features in the area have not been active since the last episode of glaciation, and there is insufficient information to confirm either the presence or absence of cavities beneath the site.

On the basis of the evidence available to date, it is not likely that significant solution activity is going on in the rock beneath the site, nor is it likely that there are large caverns beneath the site sufficiently close to the surface to cause subsidence or collapse beneath the plant, because indications of this condition would probably have been observed during or shortly after construction 20 years ago. The staff concludes that there is insufficient benefit to be gained from conducting additional onsite investigations; therefore, no further action is required.

4.4 Topic III-1, Classification of Structures, Systems, and Components (Seismic and Quality)

10 CFR 50 (GDC 1), as implemented by Regulatory Guide 1.26, requires that structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of safety functions to be performed. The codes used for the design, fabrication, erection, and testing of the Big Rock Point plant were compared with current codes.

The development of the current edition of the American Society of Mechanical Engineers "Boiler and Pressure Vessel Code" (ASME Code) has been a process evolving from earlier ASME Code, American National Standards Institute, and other standards, and manufacturer's requirements. In general, the materials of construction used in earlier designs provide comparable levels of safety.

The review of this topic identified several systems and components for which the licensee was unable to provide information to justify a conclusion that the quality standards imposed during plant construction meet quality standards required for new facilities. The staff did not identify any inadequate components. However, because of the limited information on the components involved, the staff was unable to conclude that for code and standard changes deemed important to safety, the plant met current requirements. The staff will require that the licensee complete the evaluations described in the following sections, to demonstrate that adequate margins of safety exist for those components necessary to mitigate the consequences of an accident or to ensure safe plant shutdown, and include that information in the Final Safety Analysis Report update which must be submitted within 2 years after the completion of the SEP review (10 CFR 50.71). A plan for the update is currently scheduled to be available in October 1985 (Section 5.3.25).

By letter date November 23, 1982(b), the licensee submitted an evaluation of fracture toughness of the specified components. That evaluation was reviewed by the staff.

4.4.1 Piping

Calculations similar to those presented in Section 4.2, Appendix A of Technical Evaluation Report C5257-434, which was appended to the staff's evaluation (letter dated April 16, 1982), should be performed in order to assess the impact on the usage factor of gross discontinuities in Class 1 piping systems for a medium and large number of cyclic loads.

The licensee was not able to generate the analysis required because of the inability, at this time, to define the proper cyclic loads. The licensee states that the loads will be defined as part of the analysis required under SEP Topic III-6 (Section 4.12). The licensee has agreed to perform sample analyses to confirm that there is an adequate margin of safety for piping fatigue by using the methods used by the staff's consultant, as described in the SER for this topic. This work is scheduled to be completed by June 1985.

4.4.2 Pressure Vessels

The licensee should demonstrate compliance with current fatigue analysis requirements for all Class 1 vessels.

The licensee was not able to perform the required analysis because of a lack of information on loads. The licensee stated that the information will be generated as part of the analysis required under SEP Topic III-6 (Section 4.12). The licensee has agreed to perform sample analyses to confirm that there is an adequate margin of safety for vessel fatigue by using the methods used by the staff's consultant, as described in the SER for this topic. This work is scheduled to be completed by June 1985.

4.5 Topic III-2, Wind and Tornado Loadings

10 CFR 50 (GDC 2), as implemented by SRP Sections 3.3.1 and 3.3.2 and Regulatory Guides 1.76 and 1.117, requires that the plant be designed to withstand the effects of natural phenomena such as wind and tornadoes.

The licensee has proposed to evaluate the need for and potential alternative corrective actions for Sections 4.5.1 through 4.5.5 as part of their probabilistic risk assessment (PRA). That evaluation is intended to establish the maximum windspeed at which safe plant shutdown can be ensured and the recurrence interval for that windspeed. The general method proposed by the licensee is acceptable; however, because the recurrence intervals and the associated uncertainty bounds have been established uniformly as part of the topic evaluation, the staff will require that the licensee include in their evaluation the alternative corrective actions required to withstand the NRC's determined 10-4 and 10-5 windspeed, at the upper 95% confidence limit, and perform a cost-benefit analysis to support a determination of which modifications should be performed. This evaluation is to be coordinated with the evaluation under Topic III-4.A for tornado missiles (Section 4.8) and load combinations (Section 4.13). The licensee's wind load evaluation was submitted on July 5, 1983, and is being reviewed by the staff. The staff's evaluation will be presented in a supplement to this report.

4.5.1 Windspeed

The existing design and construction of structures important to safety do not meet current licensing criteria regarding the ability of safety-related structures to resist design-basis tornado winds of 360 mph and differential pressures of 3.0 psi. As a result of its topic review, the staff recommended that the licensee should:

(1) implement modifications to meet the design-basis tornado loads,

(2) demonstrate that the consequences of their failure if subjected to tornado loads are acceptable, or

(3) demonstrate adequate resistance (i.e., no loss of function) for smaller tornado loadings and that the risk associated from larger tornado loadings is acceptable

for the following structures:

(1) concrete chimney
(2) screenhouse/discharge structure
(3) turbine building
(4) service building (includes control room, electric equipment room)
(5) diesel generator enclosure
(6) turbine building passageway
(7) containment structure

4.5.2 Differential Pressure Load

For the containment sphere differential pressure load, the staff requested that the licensee perform the evaluation described above or determine the adequacy of the venting system to prevent a differential pressure (external greater than internal) from exceeding 1.22 psig. Since that SER was issued on December 9, 1982, the staff has performed an analysis that indicates that the 1.22-psi differential limit will not be exceeded because the external pressure transient is too short and too small to have an appreciable effect on the mass of air in the containment through the 24-in. purge and vent lines.

4.5.3 Components Not Enclosed in Qualified Structures

For safety-related components not inside qualified structures, the licensee should demonstrate either acceptability for tornado loads or acceptability of the consequences of failure.

4.5.4 Foundation Capacity

The licensee should establish that foundation and soil capacities are not more limiting than the values reported in conjunction with the topic evaluation. Also, the original foundation design should be reviewed to determine whether the bearing-stress increase for wind design is acceptable.

4.5.5 Load Combinations

The licensee should determine whether operating pipe reaction loads, thermal loads, and snow loads were considered with the wind loads in the original design or any subsequent evaluation to demonstrate safe shutdown capability. If these loads were not, the effect of combining them should be addressed in conjunction with the evaluation of load combinations under Topic III-7.B (Section 4.13).

4.6 Topic III-3.A, Effects of High Water Level on Structures

The topic evaluation identified ground water loading conditions that had not been adequately considered in the original plant design. These conditions are addressed in Section 4.2.1.

4.7 Topic III-3.C, Inservice Inspection of Water Control Structures

10 CFR 50 (GDC 1), as implemented by Regulatory Guide 1.127, requires that structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. It also requires that appropriate records of design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power plant licensee throughout the life of the plant.

The licensee, in a letter dated December 21, 1981, described the current inspection program and the basis for the conclusion that an adequate program for periodic surveillance has been instituted at Big Rock Point.

The major differences identified in conjunction with the topic evaluation are:

(1) The licensee should formalize the present program in the plant procedures. The licensee provided a formal commitment to modify plant procedures in a letter dated January 14, 1983. The staff finds this commitment acceptable.

(2) The licensee does not have a program for inspecting the internal surfaces of the intake line. Considering (a) that the 1,470 ft of 5-ft-diameter pipe is buried below Lake Michigan, (b) that the required flow for safety equipment is only 2% of the normal flow, and (3) the risk to diver safety to conduct such an inspection, the staff concludes that implementation of this inspection requirement is not warranted.

4.8 Topic III-4.A, Tornado Missiles

10 CFR 50 (GDC 2), as implemented by Regulatory Guide 1.117, prescribes structures, systems, and components that should be designed to withstand the effects of a tornado, including tornado missiles, without loss of capability to perform their safety functions. Regulatory Guide 1.117 requires that structures, systems, and components that should be protected from the effects of a design-basis tornado are (1) those necessary to ensure the integrity of the reactor coolant pressure boundary, (2) those necessary to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition (including both hot

standby and cold shutdown), and (3) those whose failure could lead to radioactive releases resulting in calculated offsite exposures greater than 25% of the guideline exposures of 10 CFR 100 using appropriately conservative analytical methods and assumptions. The physical separation of redundant or alternate structures or components required for the safe shutdown of the plant is not considered acceptable by itself for providing protection against the effects of tornadoes, including tornado-generated missiles, because of the large number and random direction of potential missiles that could result from a tornado, as well as the need to consider the single-failure criterion.

The topic evaluation concluded that the Big Rock Point plant does not meet the current criteria for tornado-missile protection for the following systems and subsystems:

(1) emergency condenser

(2) fire suppression water system

(3) control rod drive system

(4) station batteries

(5) emergency diesel generator

(6) power, control, and instrumentation for the safe shutdown systems and other safety systems

(7) spent fuel pool

(8) reactor depressurization system

(9) postincident cooling system (enclosure spray)

(10) liquid poison system

The licensee has proposed to evaluate the damage probability from tornado missiles in conjunction with the probabilistic risk assessment under Topic III-2 (Section 4.5). It is the staff's position that the licensee demonstrate an ability to achieve safe shutdown using equipment that is protected against tornado missiles in accordance with the evaluation criteria described in Section 4.5.

4.9 Topic III-4.B, Turbine Missiles

10 CFR 50 (GDC 4), as implemented by Regulatory Guide 1.115 and SRP Section 3.5.1.3, requires that structures, systems, and components important to safety be appropriately protected against dynamic effects, which include potential missiles. The safety objective of this review is to ensure that all of the structures, systems, and components important to safety (identified in Regulatory Guide 1.117) have adequate protection against potential turbine missiles because of either structural barriers or a high degree of assurance that failures at design or destructive overspeed will not occur.

General Electric (GE) currently is analyzing the probability of generating turbine missiles generically for its turbine designs. This analysis will consider material properties, turbine disc design, inservice inspection intervals, and overspeed protection system characteristics as they relate to destructive overspeed missile generation. The results of this analysis will be submitted to the staff and will identify recommended inspection intervals for the disc and overspeed protection system based on plant-specific turbine characteristics and test results. On the basis of the results of the last turbine inspection, GE has recommended a schedule to all owners for the next inservice inspection (ISI) based on GE's crack-growth models. The time interval can range from 18 months to 6 years depending on inspection results.

The Big Rock Point turbine is different from the generic turbine in that it has a monolithic rotor. As a result, the staff has found the licensee's 7-year inspection schedule for this rotor acceptable. However, the topic evaluation identified a concern about the lack of redundancy in the overspeed protection for the Big Rock Point turbine. In a letter dated December 13, 1982, the licensee pointed out that the likelihood of rotor failure, even at runaway speeds, was very low because it is a monolithic rotor as opposed to the shrunk-on disc rotors typically used in nuclear power plants. A site visit by the staff indicated that the only major component in the path of a 25° cone, tangential to the rotor centerline, was the condensate storage tank. The condensate storage tank is not needed for safe shutdown in this case because the emergency condenser makeup can be supplied from the demineralized water storage tank, the potable water system, or the fire water system.

On the basis of the low likelihood of developing a turbine missile and the low consequences of such an event, the staff concluded that the addition of a redundant overspeed trip is not warranted.

4.10 Topic III-5.A, Effects of Pipe Break on Structures, Systems, and Components Inside Containment

10 CFR 50 (GDC 4), as interpreted by SRP Section 3.6.2, requires, in part, that structures, systems, and components important to safety be appropriately protected against dynamic effects such as pipe whip and discharging fluids. The safety objective for this topic review is to ensure that if a pipe should break inside containment, the plant could safely shut down without a loss of containment integrity and the break would pose no more severe conditions than those analyzed by the design-basis accidents. The topic evaluation concluded that cascaded failure of safety-related equipment is probable and that the licensee's method of analysis may be inadequate. The topic evaluation recommended that the licensee provide an improved analysis and additional protection against high-energy-line breaks inside containment. In response, by a letter dated June 22, 1983(b), the licensee provided an analysis based on his PRA and the staff's review of current leakage detection capability to show that adequate protection exists.

Specifically, it is the licensee's position that the probability of a high-energy-line break of sufficient size and in the proper place so as to cause core damage is so remote (4.7 x 10-6/reactor-year) as to render the performance of pipe stress and fracture mechanics evaluations (to show a lower probability of failure) or installation of pipe whip restraints and/or jet shields not cost effective.

The staff has reviewed the licensee's cost-benefit evaluation and concludes that plant modifications to mitigate the consequences of pipe breaks inside containment or to provide protection against possible cascade failures would not be cost effective. Moreover, in view of the plant's leakage detection capability (Section 4.16), the staff concludes that the potential for a pipe break inside containment that could lead to cascade failures beyond the design-basis accident is sufficiently small that designed protection is not warranted. However, the staff notes that, as part of an overall evaluation of plant improvements to provide additional protection against external hazards (Sections 4.12 and 4.13), the licensee should reconsider the cost-benefit decisions for this issue where they are affected by the cost-benefit findings of these other issues.

4.11 Topic III-5.B, Pipe Break Outside Containment

10 CFR 50 (GDC 4), as implemented by SRP Sections 3.6.1 and 3.6.2 and Branch Technical Positions (BTPs) MEB 3-1 and ASB 3-1, requires, in part, that structures, systems, and components important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures. The safety objective for this topic review is to ensure that if a pipe should break outside the containment, the plant can be safely shut down without a loss of containment integrity.

The intake structure contains several pumps and associated piping. Flooding caused by a failure in the fire system, the service water system, or the circulating water system, could result in submergence of the fire pumps. Spray from such breaks could also affect pumps in the screenhouse.

The fire pumps have several safety functions at the Big Rock Point plant. Accordingly, the topic evaluation concluded that the potential to damage both pumps as a result of flooding should be eliminated and that the licensee should ensure that a postulated moderate-energy-line leakage crack will not disable both fire system pumps. The topic evaluation further concluded that the plant is adequately protected from the dynamic effects of pipe failure outside containment subject to resolution of flooding from postulated leaks in the intake structure or external flooding as discussed in Section 4.2.2.

The limited PRA presented in Appendix D to this report indicates that the failure probability of the fire protection system is dominated by pump mechanical failures. The staff review of pump testing was conducted under Topics VI-7.A.3 (Section 3.1) and VI-10.A (Section 4.21). The staff has concluded that present testing programs are adequate at Big Rock Point.

The emergency condenser could be used for shutdown, with makeup from either the demineralized water system or the fire water system (if at least one fire pump is unaffected). However, makeup to the demineralized water system from the potable (well) water system requires the use of a transfer pump in the intake structure which would likely fail because of flooding; so long as a supply can be maintained to the demineralized water system, a transfer pump in the turbine building can maintain emergency condenser cooling and well-water cooling is provided for control valves.

Because the failure of the emergency cooling water sources are dominated by mechanical failures other than seals and because of the availability of shutdown systems not involving equipment in the screenhouse (Topic V-10.B, in

Section 3.1), the staff has concluded that safe shutdown can be assured when the licensee has appropriate procedures to provide emergency condenser cooling, as described in Section 4.2.4.

4.12 Topic III-6, Seismic Design Considerations

10 CFR 50 (GDC 2) and 10 CFR 100, Appendix A, as implemented by SRP Sections 2.5, 3.7, 3.8, 3.9, and 3.10 and SEP review criteria (NUREG/CR-0098, "Development of Criteria for Seismic Review of Selected Nuclear Power Plants"), require that structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena, such as earthquakes, without loss of capability to perform their safety functions.

During its topic evaluation, the staff concluded that the criteria and analyses supplied by the licensee for structures, buried piping, and portions of the reactor coolant loop piping were not adequate to resolve questions concerning analytic uncertainty or to quantify the effects of simplifying assumptions. The seismic analyses performed to date are not in accord with either SEP or SRP criteria. The licensee has indicated that it is not economically feasible to perform the analyses required to demonstrate seismic capability and quantify analytical uncertainty. The staff agrees that considerable detailed analysis would be required. As an alternative, the licensee has proposed to evaluate the seismic resistance of equipment important to safety using a combination of probabilistic methods and deterministic analyses. The specific approach is to

(1) identify those transients most likely to occur as a result of a seismic event

(2) use the PRA event trees for the transients to identify those systems that require seismic resistance

(3) identify those seismic failures that must occur to result in core damage by combining event trees

(4) provide a best estimate of the ground acceleration corresponding to building responses at which sufficient seismic failures resulting in core melt occur

(5) rank the cut sets by magnitude of seismic resistance

(6) propose modifications of equipment and structures in those cut sets that feature the lowest resistance (i.e., the weak links)

On the basis of insights from both deterministic analysis and the above probabilistic methods, the emergency condenser supports represent the weakest link. The evaluation of equipment, however, is not complete because the seismic capacity of certain equipment is not known (or at least large uncertainties exist in the estimate of such capacity). On the basis of analysis performed to date, the licensee has proposed the following:

(1) To ensure an anticipated transient without scram is unlikely, identify the weak links in the reactor internals and ensure that the control rod drive mechanism discharge piping does not crimp.

(2) Complete the cable tray evaluations using generic criteria being developed by the Owners Group and ascertain whether seismic dependencies exist between power supplies and electrical components in the routing of cable trays and conduit.

(3) Inspect valves MO7050, MO7053, and MO7063 to ensure that the valve operators will not impact surrounding structures if motion occurs during an earthquake.

(4) Evaluate or restrain the motion of valves MO7070, MO7071, MO7051, and MO7061 to ensure the motors do not strike surrounding structures if motion occurs during an earthquake.

(5) Place a mechanical block on the cleanup demineralizer hoist to ensure it cannot travel over the enclosure spray valves.

(6) Complete the evaluation by May 1985, documenting the results of the seismic capability study and identifying any additional cost-effective seismic upgrading.

It is the licensee's position that an evaluation of components other than those listed in Items 1 through 5 above is of no benefit until the capability of these components has been shown to be at least 0.12g. At that time, an evaluation of the methods by which the emergency condenser supports can be upgraded may be beneficial in determining whether or not further seismic upgrading of the plant can be justified.

The staff concurs with the licensee's proposed approach to selective seismic upgrading. The original design of Big Rock Point included a 0.05-g static horizontal load for structures, but no seismic design basis for equipment and piping. The seismic analyses performed under Topic III-6 have demonstrated that there is inherent seismic resistance in the design; however, to complete the analysis and any modifications necessary to demonstrate a consistent seismic capability for all safety-related equipment and structures would be very time consuming and expensive because of the lack of original seismic design analyses, the complex nature of the "as-built" plant, and (in some cases) lack of original construction details needed to perform seismic analyses. The offsite dose analyses performed in conjunction with SEP topics and the licensee's PRA have demonstrated that the relative consequences of accidents, even those involving core melt, are very low because of the small plant size and low population distribution around the plant site.

In view of these considerations, the staff concludes that the approach proposed by the licensee (i.e., to selectively upgrade the "weak links" in the systems and structures necessary to mitigate accidents that would be expected to result from seismic events) is reasonable and, if properly executed, would provide sufficient seismic resistance so that the health and safety of the public could be ensured. The staff will require that the licensee's evaluation address the issues raised regarding the analysis methods in the topic evaluation and the potential for failure of masonry walls (see Section 5.4.2), wherever they apply. The staff will continue to review the licensee's implementation of this approach and will describe the results in a supplement to this report.

4.13 Topic III-7.B, Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria

10 CFR 50 (GDC 1, 2, and 4), as implemented by SRP Section 3.8, requires that structures, systems, and components be designed for the loading that will be imposed on them and that they conform to applicable codes and standards.

The topic evaluation of code, load, and load combination changes affecting specific types of structural elements identified areas where existing safety margins in structures are significantly reduced from that which would be required by current versions of the applicable codes and standards. That evaluation suggested that the differences between plant design and current licensing criteria should be resolved as follows:

(1) Review seismic Category I structures at Big Rock Point to determine if any of the structural elements for which a concern exists are a part of the facility design of Big Rock Point. For those that are, assess the impact of the code changes on margins of safety on a plant-specific basis.

(2) Examine on a sampling basis the margins of safety of seismic Category I structures for loads and load combinations not covered by another SEP topic and denoted by "Ax" in the SER forwarded by letter dated September 30, 1982. (The load tables should be reviewed to ensure their technical accuracy concerning applicability of the loads for each of the structures and their significance. The seismic Category I structures considered should be reviewed to ensure completeness.)

The licensee has recommended that such detailed studies not be done, but that the safety margins be determined as outlined in the resolution of seismic loads under Topic III-6 (Section 4.12). The licensee has developed similar probabilistic analyses for the loading conditions caused by winds (Section 4.5), tornado missiles (Section 4.8), and pipe breaks (Section 4.10). The staff will require that each of these evaluations explicitly consider the affected structural elements and load combinations described above, on a sampling basis, as part of the determination of the "weak links" for all of these events. Moreover, the staff will require that the licensee consider all of these probabilistic analyses collectively when deciding on selective plant upgrading, so that a relatively equivalent level of protection is achieved for all of the hazards considered (i.e., seismic, winds, tornados, and pipe breaks) and that any necessary corrective actions are integrated to the maximum extent possible. The staff will continue to review the licensee's implementation of this approach and will describe the results in a supplement to this report. The licensee has scheduled the completion of the project by June 1985.

4.14 Topic III-8.A, Loose-Parts Monitoring and Core Barrel Vibration Monitoring

10 CFR 50 (GDC 13), as implemented by Regulatory Guide 1.133, Revision 1, and SRP Section 4.4, requires a loose-parts monitoring program for the primary system of light-water-cooled reactors. Big Rock Point does not have a loose-parts monitoring program that meets the criteria of Regulatory Guide 1.133.

A loose-parts monitoring program could provide for an early detection of loose parts in the primary system that could help prevent damage to the primary system. Such damage relates primarily to

(1) damage to fuel cladding resulting from reheating or mechanical penetration

(2) jamming of control rods

(3) possible degradation of the component that is the source of the loose part to such a level that it cannot properly perform its safety-related function

Implementation of a loose-parts monitoring program is being considered in Revision 1 to Regulatory Guide 1.133. If the staff decides to implement the recommendations of this revision, then the need to implement a loose-parts monitoring program on operating reactors will be addressed generically. The following factors were considered in making a recommendation that no modifications be done at this time:

(1) A summary of 31 representative loose-parts incidents at 31 reactors (from the value-impact statement of Revision 1 to Regulatory Guide 1.133) indicates that structural damage occurred as a result of loose parts in only 9 incidents. None of these incidents caused a safety-related accident.

(2) Most loose parts can be detected during refueling inspections.

(3) The limited PRA of this issue for Big Rock Point concluded that eliminating loose parts-induced transients by installing a loose-parts monitoring system would have no effect on risk.

4.15 Topic III-10.A, Thermal-Overload Protection for Motors of Motor-Operated Valves

10 CFR 50.55a(h), as implemented by Institute of Electrical and Electronics Engineers (IEEE) Std. 279-1971 and 10 CFR 50 (GDC 13, 21, 22, 23, and 29), requires that protective actions be reliable and precise and that they satisfy the single-failure criterion using quality components. Regulatory Guide 1.106 presents the staff position on how thermal-overload protection devices can be made to meet these requirements.

The objective of this review is to provide assurance that the application of thermal-overload protection devices to motors associated with safety-related motor-operated valves (MOVs) does not result in needless hindrance of the performance of valve safety functions.

In accordance with this objective, the application of either one of the two recommendations contained in Regulatory Guide 1.106 is adequate. These recommendations are as follows:

(1) Provided that the completion of the safety functions is not jeopardized or that other safety systems are not degraded,

(a) the thermal-overload protection devices should be continuously bypassed and temporarily functional only when the valve motors are undergoing periodic or maintenance testing, or

(b) those thermal-overload protection devices that are normally functional during plant operation should be bypassed under accident conditions.

(2) The trip setpoint of the thermal-overload protection devices should be established with all uncertainties resolved in favor of completing the safety-related action. With respect to those uncertainties, consideration should be given to

(a) variations in the ambient temperature at the installed location of the overload protection devices and the valve motors

(b) inaccuracies in motor heating data and the overload protection device trip characteristics and the matching of these items

(c) setpoint drift

To ensure continued functional reliability and the accuracy of the trip setpoint, the thermal-overload protection device should be tested periodically.

At present, thermal-overload protection for some motors of motor-operated valves at Big Rock Point does not meet current licensing criteria. However, in a letter dated February 14, 1983, the licensee justified the present design for most valves on the basis that they are not required to function during an accident and are, therefore, electrically locked out. For the remaining six valves that are required to change position, the licensee proposed to bypass the thermal overloads during normal operation except during valve testing.

The limited PRA for Big Rock Point ranked this issue as being of medium risk significance because of its effect on shutdown cooling and fire protection systems.

Accordingly, the staff concluded that the Big Rock Point satisfies the current licensing criteria for safety-related valve functions or the licensee had proposed an acceptable alternative that will provide an equivalent level of protection. Continued operation until the proposed modifications were to have been completed was found to be acceptable on the basis of past operating experience at Big Rock Point. This project is scheduled to be completed by the end of the 1984 refueling outage.

4.16 Topic V-5, Reactor Coolant Pressure Boundary (RCPB) Leakage Detection

10 CFR 50 (GDC 30), as implemented by Regulatory Guide 1.45 and SRP Section 5.2.5, prescribes the types and sensitivity of systems and their seismic, indication, and testability criteria necessary to detect leakage of primary reactor coolant to the containment or to other interconnected systems.

Regulatory Guide 1.45 recommends that at least three separate leak detection systems be installed in a nuclear power plant to detect unidentified leakage from the RCPB to the primary containment of 1 gpm within 1 hour. Leakage from identified sources must be isolated so that the flow of this leakage may be monitored separately from unidentified leakage. The detection systems should be capable of performing their functions after certain seismic events and of being checked in the control room. Of the three separate leak detection methods recommended, two of the methods should be (1) sump level and flow monitoring and (2) airborne particulate radioactivity monitoring. The third method may be either monitoring the condensate flow rate from air coolers or monitoring airborne gaseous radioactivity.

Other detection methods - such as monitoring humidity, temperature, or pressure - should be considered to be indirect indications of leakage to the containment. In addition, provisions should be made to monitor systems that interface with the RCPB for signs of intersystem leakage through methods such as monitoring radioactivity and water levels or flow.

A limited risk assessment of the importance of the sensitivity of leakage detection systems to risk was performed. This study only addressed leakage detection as it related to the small-break loss-of-coolant accident. For this event, it was determined that the importance of leakage detection capability (i.e., the sensitivity of detectors to leak rate and time) to risk was very dependent on the time for a leak to become a break. If the leak-before-break-time was short (less than the current 1-hour requirement for detection of a 1-gpm leak) or the detection time was long (more than 8 hours to detect a 1-gpm leak), the benefits of leak detection capability were low. However, this limited risk assessment does not address the staff's principal concern with respect to leakage detection, which is not the small break (high-energy-pipe break (HEPB)) inside containment but a pipe crack in a larger line (such as the recirculation lines) that grows from a small leak to a large break and the resulting effects of an HEPB. Big Rock Point was not originally designed to mitigate the effects of an HEPB (e.g., pipe whip, jet impingement, and cascading breaks). There are no physical restraints, and there may not be adequate separation between systems. Therefore, a HEPB may cause damage in other systems and may reduce the availability of mitigating systems. This aspect was not evaluated in either the Millstone Unit 1 (NUREG/CR-3085) or Browns Ferry (NUREG/CR-2802) Integrated Reliability Evaluation Program studies nor in any PRA other than that done by the licensee. For example, a plant-specific evaluation of crack size and leak rates for the emergency condenser inlet and return lines at Oyster Creek has shown that a leakage detection capability with a sensitivity of 0.1 to 1.0 gpm is necessary to detect a through-wall circumferential flaw that is four times the pipe wall thickness (e.g., approximately 3.5 in. long for a 16-in.-diameter pipe). These flow rates are predicted by analyses based on elastic-plastic fracture mechanics that have been verified on a limited basis by experimental data. Experience has shown that the sensitivity and reliability of current leakage detection equipment may be questionable (e.g., Duane Arnold safe-end cracks and Indian Point Unit 2 fan cooler leakage). Further, most crack growth processes (e.g., fatigue and stress corrosion) are time dependent, yet experience has shown that it is almost impossible to quantify the rates (e.g., rates of hours to months have been experienced). However, time to achieve the required sensitivity is important because the exposure times for transient loadings are increased and, thus, the potential for unstable failure is increased.

For some postulated break locations at Big Rock Point (Section 4.10), where separation and/or restraint is not practical or possible to mitigate the effects of an HEPB, it may be necessary to use local leak detection. The current licensing position of detection of a leak of 1 gpm within 1 hour may not be sufficient for consideration of some HEPB locations.

The staff review of this topic indicates that Big Rock Point satisfies current criteria with the exception of seismic requirements. The licensee's Technical Review Group has concluded that the emergency operating procedures will be revised to require a leak test in the event of a confirmed seismic event. Further, if the leak detection equipment is inoperable, Big Rock Point Plant would be shut down (limiting condition for operation) until such time that the equipment can be returned to service. The licensee has committed to complete these changes by the end of June 1984. The staff finds this committment to be an acceptable resolution.

4.17 <u>Topic V-10.A, Residual Heat Removal Heat Exchanger Tube Failures</u>

10 CFR 50 (GDC 45 and 60), as implemented by SRP Sections 9.2.1 and 9.2.2, requires, in part, that leakage in cooling water system heat exchangers be limited to prevent radioactive releases to the environment or introduction of impurities into the primary coolant system. As noted in the topic review for Big Rock Point, the current Technical Specifications do not contain a requirement to sample the primary system daily when the shutdown cooling system is in operation and a high level alarm on the reactor cooling water (RCW) system water tank to indicate primary system leakage into the shutdown cooling system does not exist.

Because the shutdown cooling system (SCS) heat exchangers are on the suction side of the shutdown cooling pumps, the primary system may be contaminated by a leak from the shutdown cooling system during cooling system operation and the primary system may leak into the cooling system during reactor operation.

As protection against undetected leakage into the primary system, the Big Rock Point RCW system water tank incorporates a low level alarm which will alert the plant operators to leakage through the SCS heat exchangers (or any of the other components cooled by the RCW system) when the RCW is in operation. In addition, the RCW system incorporates a radiation detector and alarm, as does the service water system which cools the RCW heat exchangers and is the ultimate heat sink.

The RCW system pressure at the two RCW heat exchangers varies from a few inches of water vacuum to a few founds per square inch gage. Because the service water pressure at these heat exchangers varies from approximately 20 to 45 psig, the possibility exists for inleakage of contaminants from Lake Michigan into the RCW system. As noted above, such inleakage could find its way into the primary coolant system during SCS operation because of the differential pressures across the SCS heat exchanger. Although this scenario presumes failures of tubing in a combination of the SCS and RCW heat exchangers, such a combination, with resultant primary system contamination, cannot be ruled out, given that no inservice inspection of heat exchanger tubes has been performed and that differential pressures would aid such leakage. Big Rock Point procedures require twice weekly analysis of the RCW system and testing for dilution of chromates (a compound that is used in the RCW system as a corrosion inhibitor) and conductivity. These tests may detect inleakage from the service water system, but added defense and early warning could be obtained by the incorporation of a high level alarm in the RCW system water tank.

Currently, only the low level alarm exists as protection in addition to the twice weekly sampling and operating procedures that require the level to be logged every shift on the control room log sheet.

As defense against primary system contamination during power operation, Big Rock Point Technical Specification 4.1.2(b) requires daily primary coolant sampling, which includes chlorides and conductivity. This could be expanded to include sampling during shutdown when the SCS is in operation and thus when leakage into the primary system is most likely.

The limited PRA for Big Rock Point rated this issue to be of low risk significance because of the need to fail two heat exchangers and because the relatively low corrosion rates limit the analysis sensitivity to sampling rates greater than the present twice weekly rate of the Technical Specifications. However, such sampling is only conducted when the shutdown cooling system is in operation and the PRA did not consider long-term effects of impurities in the systems.

As noted under SEP Topics V-12.A (Section 4.18) and VI-1 (Section 4.19), the staff has found the present chloride limits acceptable.

The periods of plant shutdown are relatively short. Any impurities that might develop in the primary coolant would be detected following plant startup, and the appropriate corrective action taken before any long-term degradation effects might begin. Therefore, the staff concludes that no further action is necessary.

4.18 Topic V-12.A, Water Purity of BWR Primary Coolant

10 CFR 50 (GDC 4), as implemented by Regulatory Guide 1.56, requires that the reactor coolant pressure boundary (RCPB) have minimal probability of rapidly propagating failure. This includes corrosion-induced failures from impurities in the reactor coolant system. The safety objective of this review is to ensure that the plant reactor coolant chemistry is adequately controlled to minimize the possibility of corrosion-induced failures. The staff's review of this topic identified the following two issues.

4.18.1 Water Chemistry Limits

As shown in Table 4.2, the Big Rock Point Technical Specifications do not meet the limits established in Regulatory Guide 1.56 for conductivity, chlorides, and pH of the reactor vessel water and conductivity of the feedwater system. On the basis of past operating experience, the staff has concluded that these differences are not significant.

4.18.2 Limiting Conditions for Operation

The topic evaluation concluded that the requirements of the plant operating procedures that govern (1) the sampling of the reactor water cleanup (RWCU) system demineralizer in service and any subsequent shifting of flow and (2) the measurement of flow every 4 hours through each condensate demineralizer in service and the daily calculation of unused capacity of each bed are not incorporated into the plant Technical Specifications. These requirements are desirable to avoid corrosion-induced failures in case of a condenser tube rupture.

The topic evaluation recommended that the licensee provide new water chemistry limits and new limiting conditions for operation of the RWCU system and condensate demineralizers unless it can be demonstrated that such changes are not necessary.

The licensee responded in a letter dated June 14, 1983. Consumers Power Company maintains that 20 years of operating experience at Big Rock Point (which includes condenser tube failures) and the ongoing inservice inspection (ISI) program have demonstrated the adequacy of the existing limits and Technical Specifications. On the basis of this experience, the staff concludes that the licensee's existing procedures are adequate and incorporating these procedures into the Technical Specifications is not warranted.

4.19 Topic VI-1, Organic Materials and Postaccident Chemistry

4.19.1 Organic Materials

10 CFR 50 (GDC 1) requires that structures and systems important to safety be designed and tested to quality standards commensurate with the importance of the safety function to be performed Also, Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," describes an acceptable method of complying with the Commission's quality assurance requirements with regard to protective coatings. The safety objective of this topic is to ensure that protective coatings inside the containment do not consist of material (such as hydrocarbons or chlorides) that could create a hazardous environment or cause material failure by blockage of screens and spray nozzles.

As a result of the review of this topic, the staff recommended that the licensee demonstrate that the alkyd enamel and urethane coatings used inside containment are qualified for design-basis-accident conditions and that these coatings will not clog the recirculation screens. Furthermore, the licensee should have a formal program for periodic inspection of these coating inside containment.

The licensee proposed to provide the results of the qualification study and implement an inspection program. The schedule to complete this project will be established by the licensee's Technical Review Group.

4.19.2 Postaccident Chemistry

10 CFR 50 (GDC 14) requires that the RCPB be designed and erected so it has an extremely low probability of abnormal leakage and gross rupture. Also, GDC 41 requires systems to control concentration of fission products released to the environment following a postulated accident.

The staff review of this topic determined that the plant uses water directly from Lake Michigan for emergency core cooling. This water can have chloride concentrations in excess of the limits established by current licensing criteria. There is no provision to control the water chemistry to within the acceptance limits for boiling-water reactors in SRP Section 6.1.1. There is also no provision to control or analyze the chloride content of the sodium pentaborate solution in the standby liquid control system (SBLCS). Therefore, at the onset of an accident, there is no assurance that the water to be used for emergency core cooling and containment spray will be maintained within chemistry conditions during recirculation to minimize the probability for chloride-induced stress-corrosion cracking of austenitic stainless steel components and to minimize chemically induced hydrogen generation (i.e., corrosion induced).

In a letter dated June 17, 1983, the licensee maintained that 20 years of operating experience and the ongoing ISI program have demonstrated the adequacy of the existing limits and Technical Specifications in view of the actual salinity of Lake Michigan. Recent operating experience with false initiation of the emergency core cooling system has shown that such events are manageable. As noted under SEP Topic V-12.A (Section 4.18), the staff does not consider the differences between the plant Technical Specification limits and the requirements for new plants to be significant.

Offsite doses for these events are evaluated under Topic XV-18 (Section 4.28), as part of the Systematic Evaluation Program. Hydrogen generation from chemical reactions between metals inside containment and the containment and core spray water will be evaluated under the TMI Task Action Plan (Task II.B.7 in NUREG-0660) and Unresolved Safety Issue A-48 in NUREG-0705 generically in the future. In the interim, hydrogen generation does not pose a serious threat for Big Rock Point because of the large containment volume in relation to the core size and because containment failure as a result of hydrogen explosions was not a dominant contributor in the PRA accident sequences. The low probability of a core-degrading accident, coupled with the reduced temperatures that would exist after an accident, significantly reduces the potential for chloride-induced stress corrosion cracking. In addition, even if such corrosion were to occur, it would occur over a relatively long period of time and only in random locations, so that the staff would not expect it to affect the consequences of the accident or the ability to maintain the plant in a safe condition following an accident. Therefore, the staff concludes that the existing chemistry limits and inspections are adequate.

4.20 Topic VI-4, Containment Isolation System

10 CFR 50 (GDC 54, 55, 56, and 57), as implemented by SRP Section 6.2.4 and Regulatory Guides 1.11 and 1.141, requires isolation provisions for the lines penetrating the primary containment to maintain an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment. The topic evaluation of the containment penetrations at Big Rock Point has identified several areas that do not conform to current licensing criteria for containment isolation. The staff's limited PRA for Big Rock Point rates the reduction in containment leakage probability as a result of improving the isolation of electrical faults as being of low risk significance because of the high likelihood of containment valve leakage (0.1/demand compared with a contribution of 1 x 10-4/year from the specified penetrations) as a failure mode. The dominant contributor to containment leakage (0.1) is a failure of an operator to close valves VPI-1 and VPI-2 or VPI-3 in penetrations H-28 and H-29 if a leak develops. However, the design of these lines was found to conform to current licensing criteria in the topic evaluation.

4.20.1 Administrative Controls

The isolation valving arrangements for the following test, vent, and drain lines, associated with containment penetrations, differ from that required by current licensing criteria:

Penetration	Valve
H-11	VFW-138 and VFW-171
H-17	Undesignated vent valve on Drawing M-108
H-27	VFP-170
H-29	VPI-101
H-36	VFP-167, VFP-168, and VFP-169

The licensee has committed to administratively control these valves, except for valves VFW-171 and VPI-101. Valve VFW-171 is on a feedwater sampling line which must be open to provide continuous sample flow. The sample line is outside containment and the boundary formed by the redundant containment isolation valves and the test line containing valve VFW-138. Because the test line containing valve VFW-138 will be administratively closed and by applying the single-failure criterion to the containment isolation valves, the staff concludes that valve VFW-171 need not serve as a containment boundary. Valve VPI-101 is in a drain line for the core spray system pump return addressed in Sections 4.20 and 4.20.3.

The staff finds the licensee's proposal to administratively control these valves with locks or seal closures acceptable, provided that each of these lines is also equipped with either a pipe cap (in accordance with the ASME Code) or a redundant isolation valve. By letter dated September 13, 1983, the licensee provided suitable controls for all of the valves.

4.20.2 Instrument Lines

The isolation provisions for the following instrument lines, associated with containment penetrations, differ from that recommended by Regulatory Guide 1.11:

Penetration	Instrument/valve
H-10	Main steam/turbine control system (VTO-1A, PT-151, PT-175, PT-176, VFW-165, VFW-166)
H-27	VPI-137, VPI-157
H-36	VPI-136, VPI-156
H-89	RP-12.3
H-90	RP-12.4
H-96	VCI-15
H-98	RP-12.2
H-99	RP-12.1

The instrument lines associated with penetration H-10 are a part of the turbine control system. The licensee has determined that the radiation levels following an accident are low enough to permit manual isolation of these lines (note: the pressure instruments have root valves), and the licensee has committed to develop appropriate procedures to identify the conditions under which these lines should be isolated. This work is scheduled to be completed by July 1984.

The instrument lines associated with penetrations H-36 and H-27 are spares. The licensee has committed to seal-close the valves on these lines. The staff finds this proposal acceptable, provided the valves are included in the administrative check list to periodically verify the isolation of these lines. The remaining penetrations (H-89, -90, -96, -98, and -99) are sensing lines for containment pressure. The pressure instruments provide signals for engineered safety features and postaccident monitoring. Modifying these lines to provide automatic isolation would jeopardize that function. The integrity of the lines and instruments is verified during each containment integrated leakage rate test. In addition, the limited PRA concluded that leakage from such small lines does not significantly increase overall risk. On the basis of these considerations, the staff concludes that no further action is necessary.

4.20.3 Local Manual Valves on Safety Systems

The isolation provisions for the following containment penetrations differ from the explicit requirements of GDC 55 and 56, in that manual rather than automatic isolation valves are used:

Penetration	Valve
H-27	VFP-30
H-28	VPI-1, VPI-3
H-29	VPI-2, VPI-3, VPI-9
H-36	VFP-29
H-112	VPI-108
H-113	VPI-4

All of these lines are associated with the core spray, post-incident cooling, and fire water systems, which serve safety-related functions to mitigate the consequences of accidents.

VPI-1, -2, and -9 are located inside the containment and would not be accessible following a significant accident. VPI-9 is currently locked-closed and under administrative control. VFP-29 and -30 are closed from the control room as part of the procedure to switch from injection to recirculation cooling following an accident. VPI-108 is a locked-open vent valve in the core spray system, in a line that returns to the containment floor drains; a check valve inside the containment isolates this line in the event of a break in the line outside containment. VPI-3 is a locked-open isolation valve in the common core spray suction line outside containment.

The licensee has concluded that most of these valves should be locked-open to ensure the safety function following an accident. In addition, the licensee concluded that procedures for remote isolation of these lines is not warranted because isolation at the wrong time by human error might exacerbate the conditions of the accident. However, if any of these systems had to be taken out of service after an accident, the operator would want to close these valves to minimize leakage outside containment. This is an example of the procedures to be developed in Section 5.3.3.3.

The staff concludes that automatic isolation for these penetrations is not warranted because of the safety functions provided by the associated systems and the low likelihood of a passive failure in these systems following an accident. However, because most of the locked-open isolation valves could be used to mitigate the effects of pipe breaks in the associated systems, the licensee has committed to develop appropriate procedures to describe the conditions under which these valves should or should not be closed and identify the indicators available to the operator to verify those conditions. This project is scheduled to be completed by July 1984.

4.20.4 Local Valves on Nonsafety Systems

The isolation provisions for the following containment penetrations differ from the explicit requirements of GDC 55 and 56, in that manual rather than automatic isolation valves are used:

Penetration	Valve
H-10	VTG-101 and VFW-ST-01
H-11	CV-4000 and CV-4012
H-17	VRW-52
H-18	CV-4105
H-20	VA-14
H-23	VCU-13
H-25	VA-7

The line associated with penetration H-10 is the main steam line drain. This issue is addressed in the context of the isolation provisions for the main steam line itself in Section 4.20.5.

For the remaining penetrations, except H-18, the licensee has concluded that the valves identified do not serve a containment isolation function because existing, redundant isolation provisions already exist, as follows:

Penetration	Isolation barriers
H-11	VFW-9, VFW-304, and VFW-305
H-17	CV-4049, VRW-313
H-20 and H-25	Closed system inside containment with check valve
H-23	CV-4091, CV-4092, and CV-4093

These isolation barriers are all inside containment, rather than one inside and one outside as required by GDC 55 and 56. However, the limited PRA for Big Rock Point and other plants has found that the valve location does not significantly affect the penetration failure probability; that is, the probability of a break between the outermost valve and the containment is small compared with the probability of failure of all isolation valves. In addition, many of these valves are normally closed. The closed systems associated with penetrations H-20 and H-25 (service air and instrument air) normally operate at a pressure higher than the peak containment pressure, providing a constant leakage check, and these systems would have to passively fail upstream of the check valve to create a leakage path outside containment.

In a letter dated June 22, 1983(c), the licensee evaluated the reliability of the instrument and service air systems. Because of the potential for air inleakage to the containment as well as failure of the check valve to restrict leakage when the compressors are inoperable, the licensee concluded that implementing a leakage test program for these systems would be worthwhile. The licensee will begin this testing program during the 1984 refueling outage and monitor the results until sufficient data have been developed to draw a definitive conclusion.

In a letter dated December 22, 1983, the licensee concluded that valves VFW-9 and -304 in the feedwater system do not serve a containment isolation function, even though leakage through them has contributed to integrated (Type A) test failures, because the system would likely be in operation following an accident. However, for an accident caused by a break in the feedwater line, these valves would serve an isolation function. Nevertheless, on the basis of the risk perspective and the typical procedures for such accidents, the staff concludes that the existing isolation provisions are adequate.

In a letter dated February 2, 1984, the licensee committed to install an automatic operator for valve CV-4049 during the 1984 refueling outage.

For penetration H-18 (demineralized water), the licensee has determined that the remote manual control valve CV-4105 can be isolated by a hand switch in the control room. The licensee has committed to review the existing procedures to confirm that the operator has adequate instructions to determine when to close this valve.

On the basis of these considerations, the staff concludes that these isolation provisions are adequate and no additional actions are necessary.

4.20.5 Main Steam Line Isolation Valve

The main steam line is equipped with only a single isolation valve (MO-7050, with valve MO-7065 on the upstream drain), rather than redundant isolation valves as required by GDC 55. In the topic evaluation, the staff recommended that the licensee qualify downstream valves in the main steam system as containment isolation valves. However, this action would require automatic closure with a diverse isolation signal and leak testing for these valves.

The licensee evaluated various leak testing programs using PRA to develop cost-benefit estimates (see Appendix H, Issue 10). The results of this evaluation were presented in a letter dated June 22, 1983(c). The licensee concluded that a program for periodic stroke testing of the main steam line isolation valve (MSIV), to improve valve reliability, should be pursued. The licensee has estimated that the cost of adding a second isolation valve, to conform to current criteria, would be approximately $150,000. The corresponding reduction in exposure was estimated to be 33.8 person-rem/ reactor-year. Conversely, the licensee estimated that a testing program to improve the reliability of the existing isolation valve would be approximately $4,000 with an exposure reduction of 20.2 person-rem. The action recommended in the topic evaluation would fall somewhere between these two estimates.

The staff has reviewed the licensee's evaluation and, although several of the assumptions are questionable, agrees that the cost of adding a second isolation valve is not warranted. This conclusion is based, in part, on the conservative assumptions in the offsite dose evaluations performed in conjunction with SEP Topic XV-19.

Currently, the containment integrated leakage rate test is the means of determining the leakage integrity of the MSIV. The periodic testing proposed by the licensee is directed at determining the ability of the valve to shut, as opposed to the ability of the valve to restrict leakage. The staff believes that both functions are important. Consequently, the staff concludes that the licensee's proposal to develop a periodic testing program is acceptable, provided that the evaluation include a study of the feasibility of conducting periodic leakage integrity tests against some baseline condition. The licensee's operability testing program development is scheduled to begin in 1985, and the data collection and analysis to prove desired reliability is scheduled to be completed by March 1989. The licensee is continuing the evaluation of the staff's proposal to provide automatic closure of the downstream valves. In the interim, the licensee will monitor the results to determine whether any trends require a more immediate action.

4.20.6 Closed Systems

The following containment penetrations are associated with closed systems inside containment that have no containment isolation valves and so differ from the explicit requirements of GDC 57:

Penetration	System
H-9	Emergency condenser vent
H-12	Service water return
H-13	Service water supply
H-14	Heating steam
H-19	Heating condensate

The emergency condenser (penetration H-9) is being reviewed in conjunction with Topic III-5.A (Section 4.10) with regard to the ability to detect leakage and take corrective action. For the heating and service water systems, the licensee evaluated the cost-benefit of installing containment isolation valves in his June 22, 1983 submittal referenced earlier. The licensee has concluded that the estimated exposure reduction (3.2 person-rem/reactor-year) does not justify the cost ($150,000).

The staff agrees that the cost of adding isolation valves is not warranted, provided the system integrity is periodically verified to qualify the system as an extension of the containment. The licensee's evaluation did not consider the cost-benefit associated with periodic testing to verify the system integrity. Therefore, the staff recommended that the licensee develop a periodic inspection procedure to identify and correct significant system leakage.

The licensee has concluded that the existing roving patrols inside the containment provide adequate surveillance to identify significant degradation in these systems. In addition, the leakage detection system (see Section 4.16) is capable of detecting leaks as small as 0.02 gpm. The licensee has estimated that the probability of a breach in these systems is more than two orders of magnitude below the probability of the dominant containment failure modes;

even then, the systems would likely be at a pressure higher than the containment pressure so that any leakage would be into the containment.

On this basis, the staff concludes that the existing surveillance conditions are sufficient and, therefore, no further action is warranted.

4.20.7 Appendix J Leak Test Requirements

On November 23, 1982(a), a number of exemptions to the containment leak test requirements of Appendix J to 10 CFR 50 were granted to Big Rock Point. The forwarding letter for those exemptions and the safety evaluation that was attached indicated that several issues in the Appendix J review were being deferred to the integrated assessment in the SEP. The following sections describe the resolution of those items.

4.20.7.1 Containment Airlock Testing Frequency

Currently, the containment airlocks (equipment, personnel, and emergency) are leak tested every 6 months. Appendix J to 10 CFR 50 requires that airlocks be leak tested within 72 hours after each use or every 72 hours if the airlocks are used daily. Therefore, the explicit requirements of Appendix J to 10 CFR 50 are not met. The Appendix J safety evaluation proposed reduced pressure leak tests within 72 hours after each use or every 72 hours during frequent use in addition to the 6-month tests as an acceptable airlock leak test schedule.

The licensee has concluded that frequent use of the personnel airlock is necessary for the safe operation of the plant; the personnel airlock is used many times a day. Airlock testing is time consuming (requiring at least 4 hours to obtain statistically significant data), even for a reduced pressure test, because the entire airlock must be pressurized. The airlocks are all of the single seal design, not the double seal design which allows testing by pressurizing between the seals. During testing of the personnel airlock, entry to containment is curtailed because the only available entrance is the emergency airlock. The emergency airlock is opened daily as a personnel safety measure to ensure operability. The equipment airlock is used a couple of times a month. Each of the airlocks is tested every 6 months, and each airlock is covered by a preventive maintenance program, including seal inspection and cleaning. Moreover, the as-found leakage observed during the 6-month tests has been quite low. The leak rates have averaged 3% to 5% (closer to 3% since 1974) of the maximum Technical Specifications leakage limit. The requirement of additional tests, even reduced pressure tests, would (1) place a burden on plant operations and (2) provide no increase in safety based on the record of the 6-month leakage tests. Installation of doors with testable seals (double-seal design) would be expensive.

On this basis, and on the basis of information from the limited PRA for Big Rock Point, the staff concludes that the present airlock leak test frequency is acceptable, provided the seals are periodically replaced in accordance with manufacturer's recommendations. In a letter dated February 2, 1984, the licensee committed to inspect these seals in accordance with the manufacturer's recommendations, which the staff understands include replacement as necessary. NRC action on this exemption request will be completed following issuance of the Final Integrated Plant Safety Assessment Report.

4.20.7.2 Testing of Main Steam and Main Steam Line Drain Isolation Valves

Currently, the Appendix J Type C leak tests of the main steam isolation valve and the main steam line drain valve are performed using water as the testing medium. Because these valves are not normally pressurized with fluid from a seal system, Appendix J requires that they be tested with air or nitrogen. The licensee has concluded that testing of the MSIV and the drain valve with air or nitrogen is not feasible. Because these valves are single valves, not a pair of valves in series, the common testing method of pressurizing the piping between the two valves in series cannot be done.

An air test of the MSIV and drain valve would require pressurizing a very large volume of piping with many other valves being used as isolation valves; this would be an impractical test. These valves are tested with air as part of the integrated containment leak rate test every 40 months. They are also tested with water during hydrostatic testing of the primary system at each refueling. Leakage during the hydrostatic tests is measured as drops of water per second.

In a letter dated February 2, 1984, the licensee committed to develop and implement a procedure, including any necessary modifications, to permit pneumatic testing of the MSIV beginning in the 1985 refueling outage. This procedure would not include the main steam line drain, because of the system configuration; however, that valve is normally closed, the line is small, and the leakage integrity is verified during both the system hydrostatic test and the containment integrated leakage test. In discussions with the licensee, the licensee has committed to develop a suitable test for the drain valve or to cut and cap the line downstream of the valve. Therefore, the staff finds the licensee's proposed action acceptable.

4.20.7.3 Testing of Isolation Devices for Closed Systems Inside Containment

The leak rate testing of isolation boundaries for the following systems, which are closed systems inside containment and which penetrate containment, was deferred to the integrated assessment because Topic VI-4 initially identified the possible need for additional isolation valves in some of these systems:

(1) service air
(2) service water
(3) heating and cooling
(4) instrument air
(5) integrated leakage rate test (ILRT) reference volume
(6) shutdown flushing

The licensee has concluded that lines associated with these systems would not rupture or leak significantly because they contain no high-energy fluids and have no openings to the containment atmosphere that provide a path to the environment. These lines are subject to the same environment as the containment shell and are provided the same surveillance for leakage during the ILRT. As further protection against leakage, the service water, service air, and instrument air systems normally operate at pressures greater than the maximum pressure during loss-coolant-accident (LOCA) conditions. The instrument air and service air systems are addressed in Section 4.20.4. These two systems have check valves inside containment and gate valves outside containment.

Results of the licensee's PRA indicate that failure of these systems is not a significant contributor to the overall containment failure probability at Big Rock Point. The staff concludes that the testing developed under Section 4.20.4 will be sufficient to demonstrate leakage integrity and no further testing is necessary.

The service water and heating and cooling systems are addressed in Section 4.20.6.

The shutdown flushing line and the ILRT reference volume were not identified in Topic VI-4 as requiring additional isolation provisions. These lines are only used when the plant is shut down and are isolated during power operation. During power operation both lines are closed to the containment atmosphere. For leakage to occur outside containment through either line requires passive failure of the line and a blank flange or pipe cap. The results of the limited PRA indicate that failure of these lines is not a significant contributor to the overall containment failure probability for Big Rock Point. Therefore, the staff concludes that Type C leak testing of these lines would not significantly improve safety and need not be conducted.

NRC action on any necessary exemption requests resulting from these findings will be completed following issuance of the Final Integrated Plant Safety Assessment Report.

4.20.7.4 Spare Penetration Testing

The licensee has committed to seal-weld the threaded pipe caps used to seal spare containment penetrations. This commitment resolves the issue of spare penetration testing because Type C leak testing is not required for welded pipe caps.

4.21 Topic VI-10.A, Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing

10 CFR 50 (GDC 21), as implemented by Regulatory Guide 1.22 and the BWR Standard Technical Specifications (STS) (NUREG-0123), requires that the reactor protection system (RPS) be designed to permit periodic testing of its functioning, including a capability to test channels independently. 10 CFR 50.55(h), through IEEE Std. 279-1971 and IEEE Std. 338-1977, requires that response-time testing be performed on a periodic basis for plants with construction permits issued after January 1, 1971. During the topic review, the following issues were identified.

4.21.1 Surveillance Frequency Requirements

The Big Rock Point Technical Specifications do not require calibration of the initiation channels for the RPS, the emergency condenser system, and the containment isolation system. Calibration of these systems is controlled by plant test procedures, which are scheduled in the Technical Specifications.

The Big Rock Point Technical Specifications specify response times but do not require response-time testing of the RPS and engineered safety features (ESF) systems. Response-time tests are controlled by plant test procedures; RPS response-time test intervals are greater than that specified in the STS. For

Big Rock Point, the staff agrees with the licensee position that operating experience justifies a test interval that is greater than that specified in the STS.

4.21.2 Reactor Protection System Response-Time Testing

Response-time testing of the RPS does not include the sensors that initiate RPS action or ESF action. Response-time testing of the ESF systems does not include the system logic that actuates the valves. It includes only the opening and/or closing time of the valves when they are actuated from a hand-switch in the control room. With regard to the testing of RPS and ESF sensors, the staff noted that neither IEEE Std. 338-1977 nor Regulatory Guide 1.118 requires response-time testing of neutron detectors. However, Regulatory Guide 1.118 does recommend the testing of cable capacitance or other suitable test. The remainder of the sensors that provide an input to the protection system logic are snap action, blind sensors. Such sensors are not suitable candidates for response-time testing in the field. However, the neutron monitoring cables and signal processing equipment could be response-time tested.

With regard to the ESF valve actuation logic, the staff has noted that it is composed of relays that are similar to those found in the RPS and the valve controls. The RPS and valve control relays are response-time tested.

The staff performed a limited PRA of this issue for Big Rock Point to estimate the improvement in overall safety if response-time testing of the ESF was required. The results of this PRA indicated that response-time testing has low risk significance. This occurs because response-time testing is concerned with events on the order of seconds and the PRA has shown that response times of minutes are sufficient for the RPS actuation to ensure the success of the subcriticality function in time to allow other safety systems to prevent core melt. Functional tests are sufficient to demonstrate functioning of the ESF on the order of minutes, and these tests are performed at Big Rock Point.

On the basis of the limited PRA and past experience at Big Rock Point, the staff believes that the additional response-time testing of the neutron detector cables and the ESF valve logic is unnecessary.

4.22 Topic VII-1.A, Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices

10 CFR 50.55a(h), through IEEE Std. 279-1971, requires that safety signals be isolated from nonsafety signals and that no credible failure at the output of an isolation device shall prevent the associated protection system channel from meeting the minimum performance requirements specified in the design bases.

For some boiling-water reactors, isolation between each reactor protection system channel and its respective nonsafety power supply is inadequate because failures of the motor-generator protection system (abnormal voltage or frequency) could result in failure to scram because of overheating of the electrical solenoid valves that control the air-operated scram valves. The review of this topic indicated that Big Rock Point is different from other GE plants because the overvoltage sensor at Big Rock Point is not in the regulator cabinet and an undervoltage relay is not provided. Furthermore, redundant protection is not provided at Big Rock Point for each motor-generator output as has been implemented at other GE plants to fix this problem on a generic basis. The staff PRA for Big Rock Point ranked this issue to be of a high risk significance (201 person-rem/reactor-year saved) and fourth out of 37 issues reviewed.

By a letter dated March 11, 1983, the licensee submitted an analysis of the protection provided. As a result of this analysis, the licensee has reduced the voltage regulator and the overvoltage protection relay setpoints to limit the maximum sustained voltage. In addition to the setpoint change, testing has shown that scram solenoid power requirements are less than the minimum rated operating conditions for all voltages below rated operating voltage down to plunger dropout. (As a result, the coil cannot overheat before a scram is initiated.) Finally, the analysis showed that motor thermal overloads provide protection against underfrequency events resulting from mechanical failure of the motor-generator sets. Underfrequency events from degraded plant bus conditions have been reviewed under Topic VIII-1.A (Section 3.1).

In view of the protection provided, the fact that the equipment is of the same quality as that used in other engineered safety features, and the fact that the plant has experienced several undervoltage transients (to scram valve plunger dropout) without equipment damage, the staff concludes that modifications to provide additional protection beyond those made by the licensee will not provide a significant increase in protection. Also, as noted in the licensee's letter of March 11, 1983, periodic replacement and testing programs for these solenoid valves have been effective in preventing multiple failures. The staff finds the modifications made by the licensee acceptable.

4.23 Topic VIII-3.B, DC Power System Bus Voltage Monitoring and Annunciation

10 CFR 50.55a(h), through IEEE Std. 279-1971, and 10 CFR 50 (GDC 2, 4, 5, 17, 18, and 19), as implemented by SRP Section 8.3.2, Regulatory Guides 1.6, 1.32, 1.47, 1.75, 1.118, and 1.129, and BTP ICSB 21, require that the control room operator be given timely indication of the status of the batteries and their availability.

As a minimum, the following indications and alarms of the Class 1E dc power system(s) status in the control room are required by current licensing criteria:

(1) battery current (ammeter-charge/discharge)
(2) battery charger output current (ammeter)
(3) dc bus voltage (voltmeter)
(4) battery charger output voltage (voltmeter)
(5) battery high discharge rate alarm
(6) dc bus undervoltage and overvoltage alarm
(7) dc bus ground alarm (for underground system)
(8) battery breaker(s) or fuse(s) open alarm
(9) battery charger output breaker(s) or fuse(s) open alarm
(10) battery charger trouble alarm (one alarm for a number of abnormal conditions that are usually indicated locally)

The purpose of the monitoring instrumentation is to ensure that the battery is connected to the dc bus by a low resistance path and to monitor battery system performance. The staff's main concern is that the battery charger output may mask a degraded battery supply during normal operations.

The review of this topic determined that the Big Rock Point control room has no indication of battery charger output current, charger output voltage, battery high discharge rate, bus voltage, battery or charger breaker/fuse status, or battery current.

At Big Rock Point, there is only one battery and one dc system for plant dc services. The onsite ac system is completely independent from this dc system. (In addition, there are four small dc systems, one per channel of the depressurization system, and separate cranking batteries for the diesel generators and diesel fire pump.) Technical Specification 11.3.5.3 provides the limiting conditions for operation for emergency power sources. An orderly shutdown must start within 1 hour after the plant battery has been declared inoperable. By a letter dated March 10, 1983, the licensee has proposed to test the continuity of the plant battery connections by monitoring battery current trends during the monthly change of battery chargers. This change in procedures with the logging of weekly pilot cell readings that became effective on April 15, 1983, is acceptable to the staff.

The staff also concludes that additional monitoring of the rapid depressurization system (RDS) batteries is not necessary because of the small loads, short load duration, and multiple redundancy (2 out of 4) provided in the RDS design. The small RDS loads and short load duration make it less likely that a dc system failure that can be masked by battery charger performance will occur. The batteries for the diesel generators and diesel fire pump are load tested during the monthly diesel starts; therefore, additional instrumentation is not recommended by the staff. The limited PRA for Big Rock Point ranked this issue to be of low risk significance because of the small effect that the loss of any one of these battery systems had on the probability of a core melt. (The ac systems are generally independent of the dc systems because dc control power is only provided to the emergency diesel breaker. RDS battery A and not the station battery provides this control power. Thus, either the diesel fire pump, and the station battery or the diesel generator, ac fire pump, and RDS A battery provide adequate cooling.)

4.24 Topic VIII-4, Electrical Penetrations of Reactor Containment

10 CFR 50 (GDC 2, 4, 5, 17, 18, and 50), as implemented by SRP Sections 8.3.1 and 8.3.2, Regulatory Guides 1.32, 1.63, and 1.118, and BTP RSB 1, established the requirements for the electrical penetrations. The review of this topic indicated that at Big Rock Point, with the LOCA environment inside containment, the low-voltage penetrations do not comply with the current criteria regardless of the initial assumed temperature because the operating times of the backup circuit breakers are excessive.

The issue of the adequacy of electrical circuit protection devices to protect containment electrical penetrations was not addressed in the limited PRA of selected Big Rock Point issues. Rather, a broader subject of the importance of containment failure by leakage rather than some other failure mode was assessed. Six different PRAs were reviewed (Millstone Unit 1, Integrated

Reliability Evaluation Program (IREP) (NUREG/CR-3085); Browns Ferry, IREP (NUREG/CR-2802); Peach Bottom, Reactor Safety Study (WASH-1400); Grand Gulf, Reactor Safety Study Methodology Application Program (NUREG-0011); the licensee's PRA for Big Rock Point; and the staff's limited PRA), and it was determined that no dominant sequence involved electrical penetration failure as a release mechanism. Failure of penetrations is less significant because the potential leakage paths are smaller than those for piping penetrations and containment ventilation isolation valve failure. Therefore, the staff concludes that this issue's importance to risk is low.

In a letter dated November 16, 1981, the licensee committed to evaluate the adequacy of the backup protection device clearing times and to provide protection against seal failure on the typical low-voltage penetrations that result from fault current.

During the integrated assessment, the licensee reconsidered the proposed action in view of the low risk importance and concluded in a letter dated April 25, 1983(b), that such an evaluation is unnecessary. The staff agrees.

4.25 Topic IX-3, Station Service and Cooling Water Systems

10 CFR 50 (GDC 44), as implemented by SRP Sections 9.2.1 and 9.2.2, requires a system to transfer heat from structures, systems, and components important to safety to an ultimate heat sink; this system shall have suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities to ensure that for onsite or offsite power system operation the system safety function can be accomplished, assuming a single failure.

The review of this topic concluded that a single failure in nonredundant pipe running off of the fire water system (or other cooling water pump discharge lines) could result in loss of system function. On the basis of the staff's review of the service and cooling water systems for Big Rock Point, only the fire protection system is considered essential and within the scope of this topic. The topic evaluation concluded that the design of this system is acceptable with the following exceptions:

(1) The licensee should verify the existence of procedures that would ensure that system flow requirements are met after a piping failure.

(2) There may be a need for system modification to eliminate potential passive single failures for which adequate compensating procedures are not available.

The staff evaluation of September 29, 1982(a), reiterated the concern about the adequacy of present plant procedures and equipment to ensure adequate emergency core cooling after a break in the fire water system.

The licensee provided the requested procedures on May 16, 1983, and the staff has found them acceptable.

4.26 Topic IX-5, Ventilation Systems

10 CFR 50 (GDC 4, 60, and 61), as implemented by SRP Sections 9.4.1, 9.4.2, 9.4.3, 9.4.4, and 9.4.5, requires that the ventilation systems shall have the

capability to provide a safe environment for plant personnel and for engineered safety features.

The topic review of the ventilation systems for Big Rock Point found them acceptable except for the following two items.

4.26.1 Hydrogen Generation - Batteries

The depressurization system batteries are ventilated by the shop area system. The plant battery is ventilated by the electric equipment room ventilation system. All of the battery chargers are sequenced onto the diesel generator, but neither ventilation system is. Hydrogen generation occurs as a result of battery charging. The staff is concerned that a hydrogen fire may result from a lack of adequate ventilation. The licensee has calculated that it will take more than 3 hours to reach the 4% hydrogen concentration flammability point. The licensee proposed in a letter dated March 31, 1983, to change operating procedures to open the truck door and a door to the electric equipment room if the normal ventilation systems cannot be restarted after a loss of offsite power.

The limited PRA for these two systems ranked the loss of ventilation to be of high risk significance. This result was based on the assumption that the contained equipment required immediate cooling to function. Such an assumption is overly conservative because the thermal capacity of the shop walls will probably provide adequate cooling and major electrical equipment room heat sources, such as the motor-generator sets, trip on loss of offsite power.

It is the staff's judgment, based on the small heat loads and the large volume of the spaces, the air circulation resulting from the opening of doors to mitigate the hydrogen buildup will provide sufficient cooling for these areas. The licensee has completed an analysis of the hydrogen buildup from the RDS batteries. As a result of this analysis the staff has concluded that sufficient time is available to open the doors in the machine shop and RDS equipment area. The licensee by a letter dated August 31, 1983, submitted a similar study of the plant battery and the electric equipment room. The results show that opening the doors to this room is sufficient to limit hydrogen concentration. The staff considers this issue resolved.

4.26.2 Diesel Generator Ventilation

The diesel generator room has a passive ventilation system. After a 24-hour diesel generator run, the licensee noted that the tar roof had started to melt. An automatic exhaust fan and new air intake louvers were installed. The new system is temperature controlled and powered from the diesel generator. The licensee has also insulated the muffler. The licensee currently has no plans to move the muffler. However, if the licensee decides to move it to the roof, the staff will require that the licensee evaluate the consequences of muffler damage resulting from strong winds or missiles on engine operability.

Aside from the muffler concern, the staff believes that the licensee's approach of demonstrating the adequacy of proposed ventilation modifications by preoperational testing ensures adequate cooling for the electrical equipment in the diesel enclosure.

4.27 Topic XV-8, Control Rod Misoperation (System Malfunction or Operator Error)

10 CFR 50 (GDC 10) requires that the core and associated coolant, control, and protection systems be designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operation, including the effects of anticipated operational occurrence. 10 CFR 50 (GDC 20) requires that the protection system be designed to initiate automatically the operation of reactivity control systems to ensure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences. 10 CFR 50 (GDC 25) requires that specified fuel design limits not be exceeded for any single malfunction of the reactivity control systems such as accidental withdrawal of control rods.

The review of this topic determined that the Big Rock Point reactor does not have either a rod worth minimizer or a rod block monitor, which is present in newer boiling-water reactors. As a result, the amount of withdrawal of a control rod is not limited by a protective circuit. A single operator error or equipment failure can result in the inadvertent withdrawal of a high-worth rod. For the staff analysis, a maximum- worth rod was chosen and a scram at 120% of full power was assummed not to occur because the local power increase was not seen at the excore detector. Instead, the power was assumed to increase to 140% of full power.

For the conservative analysis that was performed, some assemblies were predicted to have a critical power ratio (CPR) below the acceptable fuel design limit for events initiated by a single malfunction in the reactivity control system. The limited PRA for Big Rock Point rated this issue of low risk significance because of the low frequency of occurrence and the very conservative power distribution that was assumed in the analysis that resulted in core damage.

By a letter dated April 25, 1983(a), the licensee provided a new, more detailed analysis that shows a higher CPR. The staff has reviewed this new analysis and determined that Big Rock Point meets current licensing criteria for postulated control rod withdrawal accidents. The consequences of the control rod drop accidents were previously reviewed under Topic XV-13; the staff concluded that Big Rock Point conforms to current licensing criteria for those accidents.

4.28 Topic XV-18, Radiological Consequences of a Main Steam Line Failure Outside Containment

10 CFR 100, as implemented by SRP Section 15.6.4, requires that the radiological consequences of failure of a main steam line outside containment be limited to small fractions of the exposure guidelines of 10 CFR 100.

On the basis of an independent assessment of the radiological consequences of a main steam line failure outside containment, the staff has determined that Big Rock Point does not meet the current acceptance criteria for this topic. If the existing Technical Specification limits for primary coolant activity are used, the potential offsite doses would substantially exceed the applicable dose limits.

The staff's limited PRA for Big Rock Point concluded that this issue does not affect any core melt sequence and thus has no effect on core melt frequency or risk. However, because of the radiological consequences of this accident in the absence of core melt, it is the staff's position that the licensee maintain the primary coolant activity within the GE STS limits for dose equivalent iodine-131 (equilibrium and maximum) and propose a plant-specific sample frequency based on analysis techniques and plant operation characteristics. The staff, therefore, suggested that the licensee should propose and provide the basis for plant-specific action statements should the STS dose equivalent iodine-131 limits be exceeded.

In a letter dated December 16, 1983, the licensee filed a Technical Specification change request to incorporate the STS primary coolant activity limits. A license amendment is being prepared by the staff.

Table 4.1 Integrated assessment summary

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
II-2.A	4.1	Severe Weather Phenomena	No	See Sections 4.5 and 4.8	-	**	No
II-3.B, II-3.B.1, II-3.C	4.2.1	Design-Basis Ground Water Level	No	None	Yes	-	No
	4.2.2	Probable Maximum Flood	No	None	Yes	-	No
	4.2.3	Probable Minimum Water Level	No	None	Yes	-	No
	4.2.4	Flood Emergency Plan	No	Provide safe shut-down procedure	Yes	11/84	No
II.4.B	4.3	Proximity of Capable Tectonic Structures in Plant Vicinity	No	None	Yes	-	No
III-1	4.4.1	Piping	No	Evaluate impact of gross discontinuities on usage factor	Yes	6/85	No
	4.4.2	Pressure Vessels	No	Demonstrate compliance with fatigue requirements	Yes	6/85	No
III-2	4.5.1	Windspeed	No	See Section 4.8	†	**	Yes

See footnotes at end of table.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
III-2	4.5.2	Differential Pressure Load	No	None	Yes	-	No
	4.5.3	Components Not Enclosed in Qualified Structures	No	See Section 4.8	†	**	Yes
	4.5.4	Foundation Capacity	No	See Section 4.8	†	**	Yes
	4.5.5	Load Combinations	No	See Section 4.8	†	**	Yes
III-3.A	4.6	Effects of High Water Level on Structures	No	None	Yes	-	No
III.3.C	4.7(1)	Inspection Program	No	None	Yes	-	No
	4.7(2)	Use of Divers	No	None	Yes	-	No
III-4.A	4.8	Tornado Missiles	No	Provide protection of systems and components to ensure the capability to safely shut down the plant	No	††	No
III-4.B	4.9	Turbine Missiles	No	None	Yes	-	No
III-5.A	4.10	(1) Cascading Pipe Breaks	No	None	Yes	-	Yes
		(2) Jet Impingement	No	None	Yes	-	Yes
		(3) Pipe Whip	No	None	Yes	-	Yes

See footnotes at end of table.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
III-5.B	4.11	Pipe Break Outside Containment	No	Protect against common mode fire pump failures	Yes	See Section 4.2.4	Yes
III-6	4.12	Seismic Design Considerations	No	Demonstrate adequate seismic capability	Yes	5/85	No
III-7.B	4.13	Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria	No	Evaluate adequacy of orignial design criteria on a sampling basis for specified structural elements	Yes	6/85	No
III-8.A	4.14	Loose-Parts Monitoring and Core Barrel Vibration Monitoring	No	None	Yes	-	Yes
III-10.A	4.15	Thermal-Overload Protection for Motors of Motor-Operated Valves	No	Install bypasses	Yes	12/84	Yes
V-5	4.16	Reactor Coolant Pressure Boundary (RCPB) Leakage Detection	No	Modify operating procedures	Yes	6/84	Yes
V-10.A	4.17	Residual Heat Removal System Heat Exchanger Tube Failures	No	None	Yes	-	Yes

See footnotes at end of table.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
V-12.A	4.18.1	Water Chemistry Limits	No	None	Yes	-	No
	4.18.2	Limiting Conditions for Operation	No	None	Yes	-	No
VI-1	4.19.1	Organic Materials	No	Demonstrate coating qualification	Yes	**	No
			Yes	Provide formal inspection program	No	**	No
	4.19.2	Postaccident Chemistry	No	None	Yes	-	No
VI-4	4.20.1	Administrative Controls	No	None	Yes	-	Yes
	4.20.2	Instrument Lines	No	Develop emergency procedures	Yes	7/84	Yes
	4.20.3	Local Manual Valves on Safety Systems	No	See Section 4.20.2	Yes	7/84	Yes
	4.20.4	Local Manual Valves on Nonsafety Systems	No	Develop leak test and emergency procedures	Yes	12/84	Yes
	4.20.5	Main Steam Line Isolation Valve	Yes	Provide augmented test and position indication	Yes	3/89	Yes
	4.20.6	Closed Systems	No	None	Yes	-	Yes

See footnotes at end of table.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
VI-4	4.20.7	Appendix J Leak Test Requirements					
	4.20.7.1	Containment Airlock Test Frequency	No	Periodic seal replacement	Yes	-	Yes
	4.20.7.2	Testing of Main Steam and Main Steam Line Drain Isolation Valves	Yes	Modify to test steam line isolation valve and drains	Yes	12/85	Yes
	4.20.7.3	Testing of Isolation Devices for Closed Systems inside Containment	No	None	Yes	-	Yes
	4.20.7.4	Spare Penetration Testing	No	Seal weld caps	Yes	**	Yes
VI-10.A	4.21.1	Surveillance Frequency Requirements	No	None	Yes	-	No
	4.21.2	Reactor Protection System Response-Time Testing	No	None	Yes	-	Yes

See footnotes at end of table.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
VII-1.A	4.22	Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices	No	None	Yes	-	Yes
VIII-3.B	4.23	DC Power System Bus Voltage Monitoring and Annunciation	No	None	Yes	-	Yes
VIII-4	4.24	Electrical Penetrations of Reactor Containment	No	None	Yes	-	Yes
IX-3	4.25	Station Service and Cooling Water Systems	No	None	Yes	-	Yes
IX-5	4.26.1	Hydrogen Generation	No	None	Yes	-	Yes
	4.26.2	Diesel Generator Ventilation	No	Completed	Yes	-	Yes
XV-8	4.27	Control Rod Misoperation (System Malfunction or Operator Error)	No	None	Yes	-	Yes
XV-18	4.28	Radiological Consequences of a Main Steam Line Failure Outside Containment	Yes	Implement Technical Specifications	Yes	††	Yes

*See Appendix D.
**To be scheduled by the licensee's Technical Review Group within 90 days of the publication of this report.
†Under licensee evaluation.
††Under staff review

Table 4.2 Water chemistry limits

Parameter	Regulatory Guide 1.56 limit	Big Rock Point limit
Reactor coolant conductivity	(1) 10 μmho/cm requires orderly shutdown	(1) 5 μmho/cm
	(2) 1 μmho/cm with up to 0.2 ppm chloride for 72 hours per incident not to exceed 2 weeks/year	(2) Peak of 10 μmho/cm on startup until 24 hours after exceeding 20% power
Chlorides	(1) 0.5 ppm requires orderly shutdown	(1) 1 ppm
	(2) Up to 0.2 ppm with greater than 1 μmho/cm conductivity for 72 hours per incident not to exceed 2 weeks/year	
pH	(1) 5.3 to 8.6	(1) 4.0 to 10.0
Feedwater conductivy	(1) 10 μmho/cm requires orderly shutdown	(1) 1 μmho/cm at demineralizer inlet
	(2) 0.5 μmho/cm at demineralizer inlet	(2) 1 μmho/cm at inlet demineralizer outlet
	(3) 0.2 μmho/cm at demineralizer outlet	

5 NON-SEP TOPIC REVIEWS

5.1 Introduction

In a letter dated March 18, 1983, the licensee requested that the NRC integrated assessment include those licensing issues currently affecting Big Rock Point, beyond those issues raised in conjunction with SEP. In a meeting with the licensee on April 19, 1983, the staff discussed the appropriate method of performing the proposed expanded integrated assessment. During that meeting, the licensee presented a preliminary ranking of issues that they felt should be addressed in such a review. The purpose of Section 5 is to expand the Big Rock Point integrated assessment to include licensing requirements beyond those evolving from the original SEP.

This assessment includes NUREG-0737 items, multiplant action items, unresolved safety issues (USIs), and plant-specific items. For each item, the licensee identified the requirements and staff guidance currently affecting Big Rock Point which they proposed to include in the integrated assessment. In a letter dated June 1, 1983, the licensee described those issues for which they proposed alternative resolutions or schedule changes, and the safety bases supporting those conclusions. The licensee's submittal is presented in Appendix H.

The staff compared the licensee's list with the pending actions listed in the Operating Reactors Licensing Actions Summary (ORLAS), the USIs that have not yet been resolved generically, and the staff's evaluation of the Big Rock Point probabilistic risk assessment (PRA) in order to ensure that all of the pending issues have been addressed. Those issues that have not been addressed are either so far along in implementation that any assessment would be moot or they are routine licensing actions that occur regularly.

5.2 Selection of the Issues

The list of issues presented in Table 5.1 is based on the submittal made by the licensee, excluding the SEP issues which are addressed in Section 4. This list included some plant-initiated actions that are outside the scope of current NRC requirements. The licensee used the plant-specific PRA, where it was applicable, to rank issues in descending order of priority. Because of the reliance on the licensee's PRA, this IPSAR includes the results of the staff's evaluation of specific issues from the licensee's PRA as an attachment to Appendix D. In some cases, staff safety evaluation reports (SERs) for issues as they apply specifically to Big Rock Point do not exist because a plant-specific review has not been conducted or documented. In such cases, the integrated assessment team identified the requirement and its basis using the available staff guidance. Although most plant-initiated actions are primarily directed toward improved plant availability, the staff considered that they may have an implicit safety significance because they may reduce the demand rate on safety systems.

The licensee's integrated assessment of June 1, 1983, as supplemented on February 2, 1984, to include schedules, encompassed all of the pending licensing actions, plant improvements recommended by the utility's staff, and outstanding issues from the SEP reviews. Although the plant improvements are not NRC requirements, they have an explicit or implicit safety significance and, therefore, deserve consideration in the allocation of time and resources for plant modifications. For all of these issues, the licensee developed numerical priority rankings based on the collective judgments of a Technical Review Group (TRG). (See Appendix H for the details of the TRG procedures.) The licensee's TRG included representatives from plant operations and maintenance, engineering, health physics, licensing and management, and probabilistic analysis. The TRG ranked each issue with regard to (1) effect on safe shutdown and core cooling, (2) potential for significant radionuclide release, (3) effect on plant availability, and (4) effect on plant personnel safety. These rankings were based on characterizations of each issue by the technical specialists on the utility's staff and a consistent scoring system for each of the areas of interest.

The result of the licensee's integrated assessment was a prioritized list of actions which assist the licensee in (1) directing finite resources first toward issue resolutions that offer the greatest payback (i.e., reduction in risk or increase in availability) and (2) developing schedules for the various elements of engineering evaluation and design, procurement, and outage time necessary to implement the plant modification. As much as possible, the TRG evaluated the means to resolve issues, rather than the issues themselves, and considered corrective actions that would resolve several issues.

For a group of issues that ranked low on the list of priority, the TRG proposed that certain issues did not warrant further action because of their low safety significance.

The NRC staff has not attempted to review the licensee's integrated assessment methods because of the judgments involved in the numerical ranking system. Rather, the staff review team, as described in Section 2.4, has evaluated the safety significance of each issue on a plant-specific basis and formed an independent judgment of the appropriateness of the licensee's proposed corrective action and relative priority.

The staff's evaluation of the issues addressed in the licensee's integrated assessment is presented in Section 5.3. However, this list of issues does not constitute all of the pending licensing actions for Big Rock Point that existed at the time integrated assessment was conducted; the licensee has submitted additional information and/or proposed corrective actions for a number of actions for which the NRC staff review is not complete. The staff's evaluation of the resolution of these additional issues is presented in Section 5.4, and it reflects the licensee's current views on these issues as described in their letters, dated September 12, 1983, and February 2, 1984.

5.3 Additional Topic Evaluations

Appendix H contains the licensee evaluations for the issues listed in Table 5.1. The following sections provide the staff evaluation of the issues described in Appendix H and Table 5.1. The sequence of issues does not imply any relative ranking by the staff of the issues presented.

5.3.1 Reactor Depressurization System Valve Reliability

The reactor depressurization system (RDS) and code safety valves at Big Rock Point vent directly to containment atmosphere. The containment is normally occupied. Calculations show that the containment atmosphere will not support human life after a 2-minute blowdown. As a consequence, these valves must not open spuriously nor may they fail to open upon demand.

The primary defense against a failure to function is the provision of redundant, high-quality valves operating in parallel. However, the licensee as a result of the PRA and operating experience and the staff as a result of the events at Three Mile Island (TMI) have initiated improvements to measure the reliability of these valves.

5.3.1.1 RDS Pilot Valve Leakage

The RDS provides relief paths to reduce the primary system pressure and allow the core spray system to inject cooling water. The RDS consists of four parallel discharge paths, off a 12-in. line connected to the main steam line, which vent to the containment at the steam drum enclosure. Each discharge path contains an air-operated isolation gate valve in series with a solenoid pilot-operated relief valve (6-in. Target Rock). A 1½-in. bypass line around the isolation gate valve maintains pressure and temperature on the upstream side of the relief valve and contains a manual and air-operated isolation valve in series, both normally open. Position indication for the isolation gate valves and relief valves are displayed in the control room.

Plant instrument air pressure opens the isolation gate valve by a 125-V dc solenoid-operated, three-way valve; the isolation valve fails in the open position upon a loss of instrument air pressure. The relief valves are opened by separate 125-V dc solenoid pilot valves, which actuate to cause a pressure imbalance across the main valve piston of the relief valve. The relief valves do not have the self-actuation feature commonly found in other BWR designs. The relief valve will remain open until the solenoid pilot valve is deenergized. In the event that the isolation gate valve accidentally opens, the equalized pressure afforded by the bypass line will prevent the relief valve from opening because of hydraulic or thermal shock.

The licensee has recognized a need to reduce the frequency of pilot valve leakage. Pilot valve leakage can lead to premature opening and delayed reseating of pilot-operated valves. Big Rock Point does not have a high-pressure safety injection system. In the event of a spurious opening of the RDS, it may be necessary to completely depressurize the reactor. This situation presents a risk of core damage and, if personnel are inside containment, personnel fatalities.

The licensee proposed to evaluate the possible reduction in leakage and the probability for inadvertent RDS opening. The licensee's PRA currently estimates a probability of 6.7×10^{-3}/year of a failure leading to an inadvertent blowdown.

The leakage of the pilot valves and the resultant consequences do not violate any specific licensing criteria, but the challenge to operator safety and protection equipment functioning is not desirable.

The licensee has committed to develop an evaluation plan that will be coordinated with a related modification plan for the instrument air supply to the RDS recently initiated. A schedule for the evaluation plan will be established following their receipt of a report from the pilot valve vendor.

5.3.1.2 RDS Reliability - High-Pressure Recycle System

The high-pressure recycle system, proposed by the licensee, would permit the operator to provide cool makeup water to the reactor vessel via the post-incident cooling system and the high-pressure feedwater pumps using existing equipment, piping, and valves. The system would collect primary coolant discharge from the safety valves from the containment sump, cool it in the post-incident heat exchanger, and return it to the primary system through the condenser hotwell and feedwater system without use of the reactor depressurization system.

The advantages of this approach are that lower containment temperatures and radiation levels and higher core water levels will be maintainable after the simultaneous loss of both sections of the emergency condenser and the main condenser.

The work to be done includes operating procedures and operator training. Engineering analyses of piping stresses, heat transfer paths (heat balances at design flows), and assurance of valve operability at expected differential pressures have been completed. As a result of this work, the licensee concluded in a letter dated December 22, 1983, that the temperature, pressure, and flow conditions required for the high-pressure recycle function would be within the design parameters for the post-incident cooling and feedwater systems.

The high-pressure recycle system would reduce the number of challenges to the RDS valves. The staff review of the licensee PRA indicates that improvement in RDS valve reliability (including actions to reduce the number of challenges) is important to risk reduction.

The licensee has proposed to coordinate this work with the efforts to upgrade emergency operating procedures (Section 5.3.3.3) and implement a complete procedure package by May 1986. The staff does not recommend that the development of recycle procedures take precedence over the upgrading of other emergency procedures because its analysis indicates that a reduction of only 6 person-rem/reactor-year could be realized. However, the staff agrees that recycle procedures should be developed.

The licensee has indicated that the procedures would include sampling of the primary coolant activity before this water is cycled outside containment. In view of this procedural constraint and the engineering analyses conducted by the licensee, the staff concludes that the benefits of the alternate high-pressure cooling function outweigh the limited risk associated with transporting radioactive coolant outside containment in a nonsafety system.

5.3.1.3 Full-Stroke Testing of RDS Valves

For the RDS valves to be completely effective, three of the four valves must open all the way. The licensee is concerned that the present partial-stroke testing may not be adequate because it does not demonstrate that the valves can open fully. The licensee proposes to review the valve design and the test method to determine if the test is valid by March 1985. The valves are solenoid operated and even partial-stroke testing provides a complete electrical test. Continued operation is justified by the low likelihood of mechanical failures that would only permit partial movement. Similarly, the staff concludes that this project can potentially improve RDS reliability but should not take precedance over the pilot-valve leakage evaluation.

5.3.1.4 Position Indication of Power-Operated Relief Valves

As a result of the events at TMI, the NRC staff requires (NUREG-0737, Item II.D.3) direct indication of power-operated relief valve (PORV) position. Big Rock Point does not have PORVs for pressure control. The spring-operated safety valves have nonenvironmentally qualified position indication.

The licensee has determined that it is not necessary to upgrade the safety valve position indication because there are no controls nor are there any gagging devices for these valves. Although such indications could identify a stuck-open or leaking valve, containment atmosphere monitors provide equivalent indicators (Section 4.16). Therefore, the staff concludes that no further action is necessary.

5.3.2 Safe Shutdown Provisions

5.3.2.1 Alternate Shutdown System (Panel and Procedures) - Appendix R

The licensee has proposed to install an alternate shutdown control station (panel) and power supply within the immediate vicinity of the core spray room. This station would feature certain primary coolant system instrumentation and controls that are used to valve in the emergency condenser to cool down the reactor, which include a three-hour-fire-rated barrier between it and the core spray system (see Section 5.3.14.2). The action also includes the development of suitable operating procedures by which the alternate shutdown station would be used to shut down the reactor (see Sections 5.3.3.3 and 5.3.3.4). This alternative was evaluated and approved by the staff as part of the exemptions to 10 CFR 50, Appendix R, that were requested by the licensee. The staff's safety evaluation was issued by letter dated March 8, 1983. There were no open issues.

The implementation of the plant modifications has been ranked first by the licensee and is scheduled to be completed by the end of the 1985 refueling outage. The staff's limited PRA (Appendix D) identified the installation of the alternate shutdown panel as the largest single contributor to risk reduction at Big Rock Point (228 person-rem/reactor-year) out of 37 issues reviewed. The staff concludes that the licensee's proposed actions and schedule are appropriate.

5.3.2.2 Upgrade Emergency Operating Procedures

The TMI Action Plan, Item I.C.1, and the clarifying documents (NUREG-0737 and NUREG-0737, Supplement 1) required reanalysis of transients and accidents, preparation of emergency procedure guidelines, and upgrading of emergency procedures by licensees. Owners of BWRs accomplished the reanalysis of transients and accidents and development of generic emergency procedure guidelines through the BWR Owners Group. Another TMI Action Plan Item, I.C.9, required the staff to upgrade procedures to improve ease of use and to reduce the likelihood of human error by implementing good human factors practices. The BWR Owners Group has developed generic technical guidelines that incorporate some of the good human factors practices, and these guidelines will be used by Consumers Power Company staff to write plant-specific emergency operating procedures. Consumers Power Company will be required to provide details to the NRC staff as to how human factors practices will be further employed in the development and writing of plant-specific emergency operating procedures. The staff has reviewed General Electric Topical Report NEDO-24934, "Emergency Procedure Guidelines, Revision 2," dated June 1982, and issued a generic SER to all BWR licensees of operating reactors (except LaCrosse) dated February 8, 1983. The staff has found these Emergency Procedure Guidelines to be acceptable for implementation. The staff believes that the BWR Emergency Guidelines provide a basis for a significant improvement over current emergency operating procedures.

The guidelines are not complete (combustible gas control and secondary containment control guidelines are not yet included), and the staff's SER issued February 8, 1983, requires a few changes to the guidelines.

The staff has recommended that implementation of the guidelines proceed in two steps:

(1) preparation of plant-specific procedures that in general conform to the Emergency Procedure Guidelines referenced above and implementation of these procedures as outlined in Supplement 1 to NUREG-0737, transmitted by Generic Letter No. 82-33, dated December 17, 1982

(2) preparation of supplements to the guidelines that cover changes, new equipment, or new knowledge and incorporation of these supplements into plant-specific procedures

Step (1) refers to the guidelines referenced above and discussed in the SER. Step (2) refers to guideline updates that will be generated routinely after the plant-specific procedures have been put in place. Although Step (2) includes combustible gas control and secondary containment control guidelines that are yet to be developed, it is essentially a maintenance function and is not significant for Big Rock Point because of the large containment volume and lack of a secondary containment. Therefore, the licensee has no plan to implement Step (2) at this time.

During its review, the staff identified several steps in the guidelines that require minor changes. These are identified in the SER issued on February 8, 1983. The staff recommended that the licensee address these items during the implementation of Step (1). Plant-specific procedures for Big Rock Point were due on June 1, 1983. The licensee has proposed to delay this submittal until the end of December 1984 because of related design reviews such as the detailed control room design review (Section 5.3.2.3) which must be completed first.

As noted in Section 5.3.1.2, final procedures are now scheduled to be implemented by May 1986. Considering the many plant design studies and possible modifications that must be examined, the staff agrees with this schedule.

5.3.2.3 Control Room Design Review

The TMI event (NUREG-0660, Item I.D.1) and experience at other nuclear facilities have shown that existing procedures and controls may be inadequate and may hinder the operator's efforts to cope with an accident. The licensee will perform a detailed review of the man-machine interface to ensure that the operator can perform during stressful, accident conditions. As part of this review, the licensee will study control room design and operating procedures, including accident walk-throughs as a part of the process for determining the need for a safety parameter display system (SPDS). The licensee will also use this review to determine if control panel equipment identification can be improved to the point where plant transients are reduced. The staff requires that the alternate shutdown panel be included in this review.

The schedule for completion of any control room modifications that are determined to be necessary, including retraining to the new procedures (Section 5.3.2.2), will be presented in a summary report of the control room design review by April 1985. The staff agrees that the small size and unique design of Big Rock Point warrant special consideration in a control room design review; however, to ensure that the objectives of the control room design review are satisfied, the staff will require that the licensee submit the results of the evaluation and the basis for any corrective actions for staff review before implementation.

5.3.3 System Stability

To ensure safety, nuclear power plants must be operated in a manner that maintains plant parameters within the limits assumed in the accident analyses. Several methods are used to provide assurance of proper operation. One method is to require that operators be trained and experienced and follow established procedures. Such operators are given periodic license examinations. A second method is to provide the operators with automatic control systems that anticipate the need for corrective action and reduce the magnitude of transients.

As a result of plant operating experience, the licensee has proposed modifications to some nonsafety control systems. In addition, the staff has mandated changes in operating procedures and control room design as a result of the events at TMI.

5.3.3.1 Turbine Bypass Valve Control System

The turbine bypass valve at Big Rock Point is a single 100% capacity valve. The action of this valve to control reactor power has a greater effect than those in newer plants because of its relative size. (Usually a bypass capacity of 30% to 40% is provided.) In addition, the contribution of reasonance effects in the Big Rock Point main steam line on reactor power are less than that at other BWR plants because of the damping characteristics of the steam drum.

The licensee recognizes a need to improve the reliability of the turbine bypass valve electrohydraulic control (EHC) system. The system has been found to be unreliable, in that the valve has on occasion not operated properly during startup (the valve cycles open and closed) and during power operation (the valve fails to open or inadvertently opens). During power operation, failure of the valve to open results in a loss of full-power main heat sink for the primary coolant system. Failure to open can also result in a needless plant trip during a load rejection or a loss-of-offsite-power transient. Spurious operation of the valve may also cause changes in steam pressure that result in a plant trip.

The licensee has proposed to perform a study to identify the frequency and type of misoperation and possibly attribute the misoperation to some specific portion of the EHC system before contacting the manufacturer. The resolution of this issue was ranked third by the licensee. Of 37 issues, the staff PRA ranked this issue tenth with an estimated risk reduction of 26 person-rem/reactor-year based on an assumed reduction in valve failures by a factor of 10 (90% reduction). Proportionately lesser benefits would result from a lesser improvement in performance. The licensee's studies are scheduled to be completed by January 1985.

The staff believes that the action proposed by the licensee is appropriate. The staff's review of Topic XV-1, "Increase in Steam Flow," concluded that an inadvertent opening of the turbine bypass valves would not cause an unacceptable transient. Similarly, the staff's review of Topic XV-3, "Turbine Trip," concluded that the Big Rock Point Plant conforms to current licensing criteria for such transients.

5.3.3.2 Secondary System Instabilities

The licensee recognizes the need to ensure that proper primary coolant system (PCS) makeup will occur following a load rejection. Following a load rejection, the PCS should blow down through the turbine bypass valve to the condenser hot-well. As a result, the hotwell levels will swell causing a signal to open the reject valve. When the reject valve opens, a significant portion of the condensate pump discharge is diverted from the suction of the reactor feed pumps to the condensate storage tank.

The loss of feed pump suction results in a feed pump trip and thus the loss of PCS makeup during the blowdown condition. This issue has both safe shutdown and availability implications because a loss of PCS inventory could result in a low reactor water level condition that subsequently results in automatic reactor trip. The proposed resolution is to modify the existing reject valve control circuitry so that valve opening does not occur during the condition described above. The licensee's PRA has revealed that the proposed modification reduces the core damage probability from 6.2×10^{-5} to 2.5×10^{-5}/reactor-year and has concluded that the cost-benefit ratio of the proposed modification is $960/person-rem. This issue was ranked fifth by the licensee. Of 37 issues, the staff PRA ranked this issue twelfth with an estimated risk reduction of 22 person-rem/reactor-year. The staff agrees that this is an important project because the licensee has proposed a specific modification that reduces the probability of core damage by reducing the magnitude of plant load rejection transients. This modification is scheduled to be completed by the end of the 1984 refueling outage.

5.3.4 Electrical Equipment Qualification

Originally, this subject was identified as SEP Topics III-11 and III-12. Because equipment qualification was being pursued on a generic basis, this subject was deleted from SEP.

The staff, in a letter dated April 26, 1983, transmitted the Safety Evaluation Report (SER) and the Technical Evaluation Report (TER) for the Environmental Qualification of Safety-Related Electrical Equipment for the Big Rock Point Plant. The staff requested in the SER that the licensee provide, by June 1, 1983, plans for qualification or replacement of the equipment in NRC Categories I.B, II.A, and IV, in addition to the justification for continued operation required in the near term, and the schedule for accomplishing the proposed corrective actions in accordance with the Equipment Qualification Rule (10 CFR 50.49(g)).

The licensee provided a partial response in a submittal dated May 31, 1983(b). The remaining responses were provided in the June 1, 1983 schedule submittal (Appendix H).

The Big Rock Point Environmental Qualification Program Plan consists of three distinct activities: (1) failure modes and effects analysis (FMEA), (2) disposition of equipment qualification deficiencies as noted in the staff's TER regarding parameters other than aging (i.e., pressure, temperature, radiation, etc.), and (3) disposition of equipment qualification deficiencies as noted in the staff's TER regarding aging. The FMEA will be performed for certain electrical equipment to assess the need for further qualification. The FMEA will consist of an evaluation to determine (1) if the safety function is performed before environmental conditions become so harsh that equipment failure may result and (2) if after the equipment has performed its initial safety-related function, subsequent failure of the equipment will not negate its initial safety function, affect other equipment or functions, or mislead the operator. If the evaluation shows that the above conditions are true, no additional qualification efforts are necessary. The results of the FMEA were submitted to the NRC in September 1983.

Regarding equipment qualification deficiencies involving parameters other than aging, the licensee proposes to review the existing qualification bases and provide additional supporting information, where available. The licensee currently expects to submit to the NRC staff in May 1984 a revised qualification basis for each piece of equipment noted in the TER as being deficient in qualification for the parameters other than aging. This evaluation will also consider the safety significance of specific equipment based on the PRA and the FMEA. Regarding the modification of safety-related equipment during the current refueling outage, the licensee submitted to the NRC staff in December 1983 the results of a review of the existing qualification bases applicable to such equipment.

For equipment qualification deficiencies involving aging, the licensee has outlined an aging program in his submittal of April 30, 1982. The aging program currently is being developed; however, because of the significant amount of time required for data collection from vendors, performance of activation energy analysis, and receipt of manufacturer recommendations regarding component replacement, development of the program is not yet complete. When complete, the aging program will include as a minimum: (1) the identification of age-sensitive components, (2) the determination of the qualified life for such components, and (3) the timely replacement of such components. The licensee plans to complete program development and implement the replacement program in September 1984. The recent 10 CFR 50.49 rulemaking also requires that the licensee submit a list of electrical equipment important to safety. In response, the licensee informed the staff that because he has not made any modifications to the plant affecting the electrical equipment qualification list since his letter of March 15, 1982, no new equipment has been added to the original Equipment Qualification Report submitted on October 31, 1980, as updated by submittals dated January 30, 1981, September 3, 1981, and March 15, 1982. The licensee will continue to update the equipment list as a result of the reviews described above and future modifications and accordingly will submit revised enclosures to the Big Rock Point Equipment Qualification Report when appropriate.

The staff concludes that the program and schedules proposed by the licensee are reasonable. The licensee intends to use the results of the FMEA to determine where additional qualification is not necessary. Where the failure of such equipment is not expected to prevent safe plant shutdown or mitigation of an accident, the PRA will be used to confirm the conclusions drawn from the FMEA. These evaluations will serve as a basis for any necessary requests for exemptions from 10 CFR 50.49 for specific pieces of equipment.

5.3.5 Radiation Shielding

The safety of the plant personnel after an accident depends, in part, on the location of suitable shielding and filtration systems. The licensee is also interested in improving operator comfort and attentiveness.

5.3.5.1 Plant Shielding - NUREG-0737, Item II.B.2

NUREG-0737 required that existing plant designs be reviewed by January 1, 1980 and plant modifications designed by January 1, 1982. The January 1, 1980 design review was completed by a contractor for the licensee. On August 12, 1981, the staff granted a deferral of implementation of modifications until completion of the staff review of the licensee PRA. The licensee proposed additional studies of the magnitude of exposure and cost effectiveness of possible additional shielding other than that proposed by the contractor. Of 37 issues, the staff PRA ranked this project eighth with a risk reduction potential of 63 person-rem/reactor-year because of improved capability to repair long-term cooling failures. The analysis also notes that a lower ranking results from improved containment isolation capability.

The results of these additional studies were submitted in a letter dated November 7, 1983. The licensee estimated that the probability of an individual receiving 30 rem - thyroid or 8 rem - whole body is less than 2×10^{-4}/reactor-year. On the basis of this analysis, the licensee concluded this estimate is conservative and additional plant modifications to further reduce exposures would not be cost effective.

These results confirm the licensee's previous conclusion, dated December 18, 1981, relative to the Item II.B.2 plant shielding requirements. Inasmuch as the calculated personnel doses are close to the NRC design guidelines and within the National Committee for Radiation Protection guidelines and additional modifications would not be cost effective, the licensee considers that this project is complete and no further action is warranted. The staff agrees.

5.3.5.2 Control Room Habitability - NUREG-0737 - SEP Topic VI-8

This subject was originally designated as SEP Topic VI-8. Because it was also a generic multiplant issue, it was deleted from the SEP.

NUREG-0737, Item III.D.3.4, "Control Room Habitability," requested that licensees evaluate the habitability of the control room against various hazards such as chemical spills, gas, and radiation. The item also requested that licensees propose modifications to improve the habitability of the control room where necessary. By letters dated December 19, 1980(a), June 1, 1981, July 9, 1981(b), December 18, 1981, February 5, 1982, and January 13, 1983, the licensee responded to this item. By letter dated August 12, 1981, the staff deferred review of this item until completion of the staff review of the PRA at the request of the licensee. The deferment was allowed because the licensee felt that the PRA showed that no control room modifications to improve habitability were cost effective.

The licensee's analyses indicate that the doses to a control room operator would be less than 1 rem to the whole body and less than 30 rem to the thyroid (taking credit for personal respiratory protection apparatus) in the event of a significant release of radioactivity from the containment at Technical Specification allowable containment leakage rates.

The worst-case event of core melt and containment failure would make the control room essentially uninhabitable. The licensee has indicated that ventilation system modifications to maintain thyroid doses below 30 rem without breathing apparatus are not cost effective. On the basis of its review of the PRA (Appendix D), the staff agrees.

Although the PRA indicated that there are no cost-effective modifications, the licensee proposed an additional evaluation of modifications that might be cost effective for a few release sequences such as isolation of the turbine building from the administrative building which houses the control room. In a letter dated February 2, 1984, the licensee concluded that installing a seal between the service building and control building may be cost effective. A final determination and any associated implementation schedule will be established by the licensee's Technical Review Group. The staff considers this action appropriate.

5.3.5.3 Control Room Air Conditioning

The licensee had proposed air conditioning the control room to improve operator comfort during summer operations. In the process of evaluating this issue, the licensee determined that no safety or plant availability implications exist.

However, in consideration of the cost of such a system, the licensee has concluded that this modification should be performed to improve the working conditions and, thus, the overall performance of the operating staff. The staff agrees. A schedule for this project has not yet been established.

5.3.6 Containment Integrity

The licensee has proposed the following licensing actions for resolving staff concerns with regard to the adequacy of containment isolation in the SEP program (see SEP Topic VI-4, Section 4.20).

5.3.6.1 Containment Integrated Leakage Rate Test

Appendix J to 10 CFR 50 requires that the containment integrated leakage rate test (ILRT) or Type A test must be conducted without any prior adjustment or repair, so that the test will be conducted in as close to an "as-is" condition as practical. The purpose of this requirement is to establish a trend for overall degradation of the containment in time, so that appropriate corrective actions can be taken to maintain the integrated leakage from the containment to a value less than that assumed in the accident analysis. Appendix J also requires that, if two consecutive Type A tests fail to meet the acceptance criteria, the tests must be conducted at each refueling outage thereafter until two consecutive tests meet the criteria.

It has been the licensee's practice to conduct local leakage rate tests (Types B and C) before the Type A test and make any necessary repairs or adjustments. The licensee has maintained this practice because it is more efficient and minimizes the impact of the leakage tests on the outage time. Under such circumstances, it has been the staff's position that the leakage from containment before any repair or adjustments following the local tests should be added to the Type A test result to determine the "as-found" condition of the containment for comparison with the acceptance criteria. The licensee requested an exemption from this requirement through the NRC's Office of Inspection and Enforcement. Specifically, before the Type A test in 1982, the licensee encountered excessive leakage in the feedwater and resin-sluice lines. The licensee took corrective actions to reduce the leakage to acceptable values. When the leakage was added to the Type A test results, the Type A test was considered a failure.

However, local leakage rate tests are performed conservatively and often measure leakage both into and out of containment. Consequently, the staff's criteria establish a worst-case "as-found" condition. In view of the expense and time required to conduct a Type A test, the staff concluded that more frequent Type A tests need not be performed where excessive leakage is identified and corrected by local leakage rate tests. If excessive leakage is encountered in subsequent local leakage rate tests of the source isolation barriers, then the corrective action should be reassessed. Therefore, an exemption to Section III, A.6(b) of Appendix J to 10 CFR 50 was issued on July 29, 1983.

5.3.6.2 Containment Purge and Vent

As a part of his resolution of Generic Issue B-24 (letter dated November 29, 1978), the licensee has committed to install a debris screen over the intake for the ventilation system discharge line to protect the isolation valves. The modification is scheduled to be completed in February 1985. Of 37 issues, the PRA review ranked the provision of adequate debris protection high, with an estimated risk reduction of 111 person-rem/reactor-year.

In addition to the question of debris blocking valve motion, the events at Salem Unit 1 and Millstone Unit 2, which initiated Generic Issue B-24, raised the question of the adequacy of the motors that operate containment valves. The staff's evaluation of this issue is contained in its letter of June 28, 1983, to the licensee.

The staff's evaluation determined that a problem existed with the design of the air operator for the isolation valve on the discharge line. Under the assumption that maximum containment pressure is developed before the valve seats, excessive air pressure develops in the actuator and excessive forces result in the valve linkage.

Enlarging the actuator can reduce these forces to acceptable levels. The licensee had committed to replace the actuator, but the necessary cylinder length and the actuator peak pressure had not been defined. The licensee has extended the valve motor cylinder 3 in. to maintain the peak closing pressure below 200 psig. The staff finds this modification acceptable.

A third issue raised in the staff evaluation was the seismic capability of the valves. The licensee has concluded that seismic integrity and qualification of these valves is not necessary because other containment failure modes dominate seismic risk. This issue will be addressed in the staff's review of the licensee's overall seismic evaluation (Section 4.12).

The remaining issues raised in the staff's evaluation concerned the frequency of isolation valve testing and limits on purging periods. The implementation criteria for Generic Issue B-24 recommend leakage tests for the isolation valves every 6 months and limits on the amount of time a plant can purge the containment atmosphere.

In the long history of Big Rock Point, there have been no consistent trends of excessive leakage in the containment purge isolation valves. Moreover, the plant design was originally predicated on continuous ventilation of the containment. The site and plant characteristics are such that the consequences of an accident are far less severe than for the typical plants for which the staff's criteria were developed. The staff's PRA evaluation for this issue concluded that restricted purging periods and increased surveillance could together result in an exposure reduction of 99 person-rem/reactor-year; either action could result in an exposure reduction almost as great as the total. Because the plant is designed to be continuously ventilated, restricted purging periods would jeopardize plant operation. However, increased surveillance of the isolation valves to demonstrate operability and gross leakage integrity appears to be a viable and potentially cost-effective means to achieve a large reduction in risk. Therefore, the staff will require that the licensee evaluate alternatives and implement an optimum surveillance method and frequency for the containment purge isolation valves.

5.3.7 Hydrogen Monitoring - NUREG-0737

TMI Action Plan Item II.F.1.6 requires that systems be provided to inform the operator of hydrogen levels within containment so that mitigation equipment (e.g., hydrogen recombiners) can be placed into service to prevent flame propagation or detonation. The licensee contends that hydrogen detonation levels will not be reached at Big Rock Point even if the entire core melts. This is due to the large volume inside containment relative to the small fuel inventory in the core.

The staff reviewed this issue as part of its review of the licensee's PRA (see Appendix D) and concludes that the relatively small amounts of hydrogen that might be generated because of metal-water reactor (fuel cladding) or chemical reaction with coatings (see Section 4.19.2) do not represent a significant contributor to the failure of containment. Similarly, the staff does not believe that enough hydrogen would be generated in the short term which could burn and affect the function of equipment inside containment. However, this evaluation has not considered the long-term (e.g., weeks) effect of hydrogen produced by radiolysis. The staff believes that such long-term hydrogen monitoring capability might be useful because:

(1) It may enhance the ability to determine the amount of core damage.

(2) It would identify whether any action is necessary to control long-term hydrogen concentrations.

Because of the slow evolution of hydrogen by radiolysis, the staff concludes that sufficient time would be available to control hydrogen with the existing systems. Therefore, the staff recommended that the licensee evaluate the benefits and costs associated with such long-term hydrogen monitoring capability.

The licensee has conducted such an evaluation and concluded that specific provisions for long-term hydrogen monitoring are not necessary because it would take months for the hydrogen concentration to even approach combustible limits. The staff has conducted confirmatory analyses that indicate that, under the most adverse circumstances (i.e., complete core melt and maximum hydrogen generation from radiolysis and the decomposition of paints and coatings), the hydrogen concentration would approach combustible limits in a few weeks. However, under these conditions, other failure modes (e.g., isolation valve failures) tend to dominate risk. Under more likely accident scenarios (and recognizing that the licensee's coatings do not contain zinc), the hydrogen evolving would not approach combustible concentrations until well after the staff would expect accident recovery operations to be under way. Therefore, the staff agrees with the licensee's conclusion and considers this issue resolved.

5.3.8 Scram Discharge

Operating experience at Big Rock Point and other BWRs has identified various problems with the instrumentation and valves associated with the scram discharge volume (SDV). A failure to isolate the SDV during a scram could result in a loss-of-coolant accident (LOCA) inside containment. (This is an example of the unique design of Big Rock Point. Typically for other BWRs, this would result in a LOCA outside containment.) Premature isolation and control rod drive seal leakage or improper venting may result in a failure to scram. Several projects in this regard have been undertaken by the licensee.

5.3.8.1 Single Channel Reset

During testing following a plant modification, the licensee discovered an anomaly in the pneumatic system of the reactor protection system. If the pneumatic pressure (air header) is low coincident with a reset of a scram channel, the scram dump tank valves would open before the control rod drive discharge valves close. The licensee was concerned that, in a similar manner, the control rod drive discharge valves might open before the scram dump tank valves close; this condition would result in a loss-of-coolant accident. Therefore, the licensee proposed to conduct an evaluation of valve coordination.

The licensee completed that evaluation and submitted the results in a letter dated November 7, 1983. The licensee concluded that the scram dump tank will isolate very quickly afer the control rod drive discharge valves open, ensuring adequate scram discharge volume, and the scram dump tank valves are open when the control rod drive discharge valves are closed (reset condition). The licensee has further indicated that the previous experience was most probably caused by loose fittings in the pneumatic system; the preventive maintenance procedures have been modified to include the inspection of these fittings.

The licensee has concluded that no additional action or system modifications are necessary. The staff agrees.

5.3.8.2 Scram Dump Tank Valves - Lack of Redundancy

The SDV drain and vent valves are not redundant at Big Rock Point. This aspect of the SDV design is related to the timing issue (Section 5.3.8.1) but also involves other single failures (both failure to open and failure to close).

The licensee has proposed to conduct a more detailed risk analysis for this system and to evaluate alternative designs. This issue is ranked fifteenth by the licensee. The results of this evaluation are scheduled to be completed by July 1984.

5.3.8.3 Scram Dump Tank Level Instrumentation

The present design uses level switches from a single pair of 2-in. headers as compared with the usual 1/4-in. instrument line. A staff review of operating plant experience (Generic Letter 81-18 dated March 30, 1981) recommended redundant and diverse instrumentation from independent headers.

The licensee PRA indicates that these generic actions proposed by the NRC staff will not provide a significant improvement in safety. The staff PRA indicates that only 4 person-rem/reactor-year could be saved. This staff figure does not include the exposure "spent" in installing or testing the additional equipment.

The existing design does not meet the current requirements for redundancy and diversity as described in Generic Letter 81-18. However, in view of (1) the small improvement in reliability (see Appendix D) in relation to qualitatively assessed high costs to backfit these requirements and (2) the staff's judgment that the unique design of the scram dump tank piping which is less likely to be susceptible to common mode failures, the staff concludes that modifications are not necessary.

5.3.9 Water Purification System

Several plant projects have been recommended to improve the design and performance of water treatment systems. None of these items involve reactor safety concerns.

5.3.9.1 Cleanup Demineralizer Pump

The cleanup demineralizer system pump is required for continuous full-power operation. The pump is of the canned rotor design and has experienced frequent motor case erosion. A summary of cleanup pump failures and outage data for a 10-year period is provided in Appendix XIII of the licensee's PRA.

The most common source of failure of the cleanup pump is failure of the rear bearing, which causes the rotor to become misaligned. Operated in this manner the rotor contacts, and wears down, the pressure boundary between the rotor and the stator housing. If wear is great enough, primary coolant enters the stator housing sometimes shorting the windings. The operator may notice degradation of cleanup pump performance during his periodic inspections of the cleanup system (i.e., the pump is hot or noisy) or when investigating the source of 480-V grounds on the cleanup pump motor control center when shorted windings occur.

An event in 1980 resulted in the release of primary coolant to the containment. The operator noticed the failure on his rounds after discovering water on the floor in the cleanup pump area. Primary coolant entering the stator housing leaked to the floor through a broken seal weld in the stator housing. Leakage was estimated at 200 ml/minute. (In the licensee event report two past incidents are reported where similar failures occurred, but details of these cleanup pump failures or the resulting leakage rates are not available.) Maximum possible leakage through this path is limited to that flow which can pass through the cooling line (approximately 3/8-in. tubing), bearing assembly, and stator housing. This path restricts loss of coolant to, at most, the lower end of the small-LOCA category. No analysis is available on the actual potential leak rate. A modification was developed for the control valves to the cleanup pump which was intended to ensure adequate bearing assembly cooling even during periods when the pump is dead headed. This modification does not appear to have reduced the maintenance required for the cleanup pump. Therefore, the licensee has decided to provide a bypass around the pump permitting operation of the cleanup system by way of the differential pressure across the recirculation pumps. Cleanup pump operation would then be restricted to periods when the plant is shut down, minimizing its operation and maintenance.

Isolation of reactor letdown to the demineralizer system was evaluated for safety in Section 4.20. The staff found this line to be isolated adequately. The licensee ranked this issue tenth. The project schedule will be established by the licensee's Technical Review Group. The staff agrees with the action proposed by the licensee.

5.3.9.2 Acid Line Extension

At present the neutralizer acid tank is filled by hand. The licensee proposed to provide a pumping system to reduce the exposure of workers to spills.

This issue is ranked fifteenth (note: several issues have the same rank) by the licensee and is scheduled to be completed by May 1984. The staff agrees with the action and schedule proposed by the licensee.

5.3.9.3 Acid and Caustic Tank Problems

The licensee proposes to replace corroded components in the water treatment facility that use strong caustic and acid solutions. These modifications would reduce the potential for chemical spills which could be costly and unnecessarily expose workers.

This issue is ranked twenty-fifth by the licensee and is scheduled to be completed by August 1984.

5.3.10 Reactor Coolant System Isolation

At present, there are some reactor coolant system vent and drain lines that only have a single isolation device. The licensee has proposed a program to identify such lines and to add a second valve or to cap the line. The licensee's PRA indicates that, at present, the LOCA probability through these lines is 2 x 10-3/year, with a resultant core damage probability of 6.9 x 10-5/year.

The licensee has ranked this issue eighteenth. Of 37 issues, the staff PRA ranked this issue eleventh, with risk reduction of 9 person-rem/reactor-year. This project is scheduled to be completed by the end of the 1984 refueling outage. The staff finds the licensee's proposed action acceptable.

5.3.11 Radiation Monitoring

The licensee has several projects underway that involve changes in radiation monitoring systems that were required by NUREG-0737, Item II.F.

5.3.11.1 Stack Gas Monitoring

NUREG-0737, Item II.F.1, requires an improved effluent radiation monitor. The licensee had obtained and installed such a device, but had not been able to obtain the spare parts necessary to satisfy the repair times required by the associated Technical Specification.

This issue was ranked seventeenth by the licensee. The licensee had estimated that the spare-part inventory would be available in January 1984, at which time the system will be put into service.

The system was put into service in December 1983. Accordingly, this issue is resolved.

5.3.11.2 Containment High Range Monitor

NUREG-0737, Item II.F.1.3, identifies specific requirements for a containment high range monitor. The staff evaluated the implementation of this requirement as part of Amendment No. 54 to the license and concluded that the operability and surveillance provisions for the containment high range radiation monitor are acceptable. However, at the time of the integrated assessment, the licensee had not yet obtained a suitable calibration source that could be used to put the monitors into service. The licensee was attempting to obtain a calibration source that is large enough and that can be handled safely. Until the instrument is calibrated, it cannot be used.

The licensee ranked this issue thirty-third and subsequently obtained a suitable source. The staff considers this issue to be completed acceptably.

5.3.12 Annex and Warehouse Modification

The licensee has proposed a project to improve stock storage for qualified equipment and to relocate office space by modifying the warehouse and moving the offices to the training annex. The project will require structural modifications in the warehouse and training annex. The existing warehouse arrangement does not have suitable fire exits for an office complex.

This project will improve the licensee's ability to maintain the plant. The stock storage would be expanded so that qualified replacement parts would be more accessible and complete. The modified office space would tend to improve the efficiency of the plant staff and improve fire safety.

This issue is ranked nineteenth by the licensee. The scope and schedule for this project will be established by the licensee's Technical Review Group. The staff agrees with the licensee's proposed action.

5.3.13 Incore Detectors

The present plant Technical Specifications require that the incore flux monitoring system be operable. The incore system has no safety significance because the excore detectors perform all safety functions and are calibrated by heat balance and flux wires are used to check for peaking.

The licensee has proposed to change the Technical Specifications to delete the operability requirement for the incore detectors. The staff review indicates that this system was provided originally to determine neutron flux distribution in both the axial and radial planes during operations. The same information is also provided by a flux wire system that is counted after a wire is activated in one of the incore detector tubes. Section 7.6.2.4 of the "Final Hazards Summary Report for Big Rock Point" states that these flux monitors were expected to provide data to verify analytical predictions during initial power operations and major rod programming (Consumers Power Company, 1971).

The staff notes that, after 20 years of operation, the fuel design and rod positioning constraints are relatively well known. Furthermore, periodic checks are made using the flux wire system because the incore fission chamber system has not been reliable. The staff concludes that the incore detectors are not necessary for safety and should not, therefore, be required in the Technical Specifications. The staff has also concluded that the flux wire system should be in the Technical Specifications because it is used to confirm analytical information on core performance.

The final resolution of this issue will be established by the licensee's Technical Review Group.

5.3.14 Fire Protection

The plant modifications resulting from the staff's review of conformance with 10 CFR 50, Appendix R, have not all been completed for Big Rock Point. The licensee's Technical Review Group reassessed the following specific commitments resulting from the fire protection review. The licensee has distinguished these proposed modifications from those associated with the alternate shutdown capability described in Section 5.3.2, although they are related. These issues were addressed in the staff's evaluation of the licensee's request for exemption from Appendix R dated March 8, 1983.

5.3.14.1 Associated Circuits

10 CFR 50, Appendix R, requires that safe shutdown equipment be isolated from associated circuits so that hot shorts, shorts to ground, or open circuits will not prevent operation of the safe shutdown equipment.

After extensive analysis and discussion with the staff, the licensee committed to the following:

(1) Procedures are to be developed to examine the position of numerous valves and operation of one pump to determine if maloperation has occurred as a result of a fire. A manual procedure for operating the equipment (e.g., disconnecting circuitry, operating valves manually, and providing prepared emergency repair cables to operate pumps) would then be established. (These are items that have a long-term effect on safe shutdown. None are needed in the near term to reach and maintain hot shutdown safely.)

(2) The emergency condenser inlet valves were the only equipment items identified by the licensee that could prevent the ability to reach hot shutdown as a result of a credible combination of short and/or open circuits. In the present configuration of the inlet valves control circuitry, a single short circuit of two wires in the control cable can close an inlet valve. Because the plant has run with one inlet valve closed in the past (as a result of a leaky outlet valve), it would take only one short circuit and one open circuit to prevent operation of the emergency condenser (as a result of a closed and a disabled inlet valve). Because a fire in the electrical equipment room or penetration area could cause this loss of the emergency condenser and also could disable the RDS/core spray and cause loss of offsite power at the same time, there would be no method available to shut down the plant.

As a result, the licensee has committed to reroute one wire (the close-coil wire) from each of the two circuits with the rest of the alternate shutdown circuits from the control room to the emergency condenser deck. This prevents the possibility of shorts closing the valves as a result of fires in the electrical equipment room, penetration areas, and elsewhere.

The licensee ranked this action thirty-second, and the modifications are scheduled to be completed by the end of the 1985 refueling outage. Of 37 issues, the staff PRA ranked this issue third, with an estimated risk reduction of 204 person-rem/reactor-year.

The staff concludes that the actions proposed by the licensee are appropriate. However, in view of the relative importance of this issue in the staff's PRA, the staff recommends that this modification be completed as soon as possible.

5.3.14.2 Loss of Offsite Power

10 CFR 50, Appendix R, requires that safe shutdown be achieved without use of offsite power within 72 hours following a fire because a fire could destroy the offsite power source or result in a turbine trip that might cause degraded grid conditions. In addition, GDC 17 requires that onsite power sources be capable of performing their intended function assuming offsite power is not available.

To satisfy the requirements of 10 CFR 50, Appendix R, the licensee relies on the RDS/core spray combination as an alternate means of safe shutdown in the event of any fire that affects the alternate shutdown panel equipment. In other words, if a fire in the core spray pump room or on the emergency condenser deck or at the south face of the steam drum wall would disable the alternate shutdown system, the emergency condenser could not be used to shut down. Instead, the plant must rely on the RDS/core spray combination as the redundant counterpart to the alternate shutdown system. This requires that Big Rock Point must provide for separation between redundant systems in accordance with Appendix R. To meet a literal interpretation of the separation criteria, the following modifications would have to be installed:

(1) Radiant energy shields must be installed between the emergency condenser outlet valve conduits and the RDS conduits and valves (both on the south face of the steam drum enclosure and on the emergency condenser deck, i.e., wherever the circuits are within 20 ft of each other).

(2) A radiant energy shield must be installed between one emergency condenser inlet valve and the RDS valves on the emergency condenser deck. The inlet valve circuit is in the same conduit as the outlet valve up the wall and across most of the deck. Therefore, only one shield would be needed until the wires split on the deck.

(3) A three-hour-fire-rated barrier must be constructed between the core spray pumps and all alternate shutdown panel equipment and conduits. This would include tearing out and replacing the concrete block wall in the entrance to the core spray pump room and rerouting/redesigning conduit runs from the battery outside the pump room. (The seismic conduit design,

which was already completed, required that the conduit be routed directly into the room and over to the shutdown panel. This conduit must now be redesigned to run underground outside the room and come in the back of the room inside a three-hour-fire-rated shutdown panel enclosure.)

The licensee's Technical Review Group (TRG) evaluated the above three actions as the proposed resolutions. During the course of its evaluation, the TRG considered the following:

(1) A fire in a core spray room, along the emergency condenser deck, or up the steam drum wall is very unlikely because of a lack of potential fire sources.

(2) A fire in the aforementioned areas coincident with a loss of offsite power is even more unlikely.

(3) The cost to complete the proposed resolution is not justified given the likelihood of fire in the areas of concern coincident with the loss of offsite power.

On the basis of these considerations, the licensee's TRG ranked this issue forty-second. Moreover, because of the low likelihood of a fire in these areas coincident with a loss of offsite power, the TRG concluded that these modifications would not be cost effective and, therefore, need not be completed.

The limited PRA for this issue concluded that protection against a fire that could potentially disable both the RDS/core spray combination and the emergency condenser could reduce exposure by 7 person-rem/reactor-year. As described in Appendix D, that analysis conservatively assumed that the frequency of fires in the area is 3.3 x 10-3/year because there are no fire detectors or suppression equipment in that area. The limited PRA also notes that there is no reason for combustible material to be present in that area.

However, during site visits, the staff has often noticed rags, trash, and other potential fire sources on the emergency condenser deck. Therefore, the staff concludes that the limited PRA for this issue is not overly conservative. The modification that would correct this issue is a radiant energy shield (i.e., not a fire barrier but a reflective shield that would prevent radiant heat from melting cables, relays, etc.) between the emergency condenser inlet valves and their associated wiring and the RDS valves and their associated wiring above the level of the deck. On the basis of the exposure reduction and the estimated costs of such a modification, the staff concludes that this modification should be installed.

With regard to the three-hour-fire-rated barrier between the alternate shutdown panel and the core spray pumps, the staff notes that this modification resulted because a fire at the alternate shutdown panel would cause a loss of the emergency condenser. Because of the importance of the emergency condenser for safe shutdown for this and other hazards, the staff recommends that the licensee reevaluate the design of the emergency condenser logic and the three-hour-fire-rated barrier. The staff will require that the licensee either revise the design to preclude the failure of the emergency condenser or install the three-hour-fire-rated barrier.

In a letter dated February 2, 1984, the licensee committed to install a radiant-energy shield on the emergency condenser deck and seal penetrations in a core spray room block wall so as to provide a three-hour fire barrier for the alternate shutdown panel. The staff finds these actions acceptable. These modifications will be complete by the end of the 1985 refueling outage.

5.3.15 Heating and Cooling Heat Exchanger

The licensee has determined that the tube bundle in each of the heating and cooling heat exchangers is beyond economical repair. The present plant design treats this bundle as a containment barrier.

The licensee has proposed to replace the "B" bundle, then the "A" bundle, using different materials to minimize the potential for leakage to develop. Maintenance valves currently are used to isolate a leaking bundle. These manual valves, however, are inside containment; thus, they cannot be used during an accident (Section 4.20.4).

The licensee has ranked this issue thirteenth and has scheduled completion in July 1984. The staff agrees with the licensee's proposed action and schedule.

5.3.16 Panel C-52 Ventilation

Control panel C-52 is inside containment. It houses power supplies for vessel level indication. Plant operating experience has shown that changes in temperature of these power supplies causes drift in level instrumentation indication.

In 1979, modifications were performed on the primary coolant level elements removing the temperature compensation from the cold reference leg of each element. The purpose of these modifications was to eliminate the possibility of reference-leg flashing during loss-of-coolant transients of a particular size and location in the primary system.

Removal of the temperature compensation permitted the reference-leg temperatures to follow ambient conditions. Because the ambient temperature was different at each level element, level indications varied by several inches depending on the element to which the level instrument is connected.

Additional modifications to the level elements were performed in 1980. This modification added heating elements to each reference column raising the reference-leg temperature slightly above ambient conditions to eliminate the variation in reference-leg average temperature. The temperature controllers for each reference-leg are located in panel C-52. The drum level controllers are set to maintain an average reference-leg temperature of about 200°F, the reactor level controllers of about 185°F. An annunciator in the control room alarms if the actual average temperature of a reference-leg is higher or lower than the controller setpoint by 10F°. The annunciator also alarms on an average reference-column temperature that is 5F° above the controller setpoint. Exceeding this alarm setpoint automatically disconnects the element from its power supply allowing the reference-leg temperature to drop to ambient conditions. This lower temperature causes instrumentation connected to the level element in question to indicate artificially lower primary coolant system setpoints. Operator response to the annunciation is presented in Procedure ALP 1.14.17.

Technical Specification 6.1.2 requires that the measured reference-leg temperatures be less than 250°F, and 6.1.5 requires that the level instrumentation be tested annually. This testing requirement was found acceptable during the review of Topic VI-10.A.

Panel C-52 is a simple, closed steel cabinet with no provisions for ventilation. The environment within the cabinet is warm when the electrical equipment is in service. Spurious high reference-leg temperature alarms have occurred in the past, which clear in a relatively short time after the door to the cabinet is opened to investigate. A failure of one of the controllers occurred in May 1982, which also may have been caused by the environment within the cabinet.

The licensee has proposed to provide improved level indication by improving the ventilation for panel C-52 and ranked this issue thirty-second in importance. This project is scheduled for completion in December 1984.

The staff, in reviewing this issue, noted that previous operating experience indicated several false low level alarms as a result of this problem. The fact that a ventilation problem causes false low level alarms is of no immediate safety concern because it is a "fail-safe" event for automatic system operations. However, this situation could impair the operator's ability to respond to an accident in which vessel water level is a key parameter. The staff agrees with the licensee's proposed actions and schedule.

5.3.17 Valve Reliability

During plant design reviews that were conducted as a part of the licensee's PRA, some air-operated valves were found that were not being operated at their designed pressure.

Although no failures of equipment have occurred, the licensee has proposed to conduct a study to determine the proper pressure for each air-operated valve manufactured by BS&B and to make adjustments where necessary. The licensee has ranked this issue thirty-second (note: several issues have the same rank).

Of 37 issues, the staff PRA ranked this issue fifth with an estimated risk reduction of 85 person-rem/reactor-year.

The staff believes that this is a worthwhile project. The scheduling of this project should coincide with other maintenance and repair activities to minimize personnel exposures. Therefore, the licensee's Technical Review Group will establish a completion schedule for this project consistent with the availability of all of the necessary data, including vendor specifications.

5.3.18 Recirculation Pump Trip

By confirmatory order dated February 21, 1980, the staff approved the licensee's commitment to install a trip on the recirculation pumps to help limit the consequences of an anticipated transient without scram (ATWS). However, in License Amendment No. 38 dated January 15, 1981, the staff extended the deadline for installation of the trip until completion of the staff's review of the Big Rock Point PRA. The licensee felt that the PRA showed that the trip is not necessary. The staff granted the extension based on design differences between Big Rock Point and more modern BWRs which make the consequences of an ATWS less severe at Big Rock Point.

The licensee has now determined that this action is not cost effective at the estimated $93,000/person-rem saved. The staff's PRA concluded that this modification may save 4 person-rem/reactor-year. On the basis of recommendations from the staff and the Advisory Committee on Reactor Safeguards (ACRS), the licensee evaluated other alternatives for a reactor pump trip that would provide the same function at a lesser cost. Specifically, the licensee considered tapping the automatic closure signal for the main steam line isolation valve.

The results of this evaluation indicate that the minimum cost would be in excess of $20,000 because of the quality control requirements for work on the reactor coolant pressure boundary and the plant modifications to route signal and control cables. The actual costs would likely be two to three times that value. Therefore, the licensee maintains that, in view of the small risk reduction potential, such modifications would not be cost effective. The staff notes that, unlike larger BWR plants, Big Rock Point does not need a pump trip feature to compensate for positive pressure reactivity at the end of core life. Therefore, in view of the small risk reduction potential, the staff agrees that a pump trip modification is not warranted.

5.3.19 Instrumentation To Detect Inadequate Core Cooling

NUREG-0737, Item II.F.2, proposes instrumentation to detect inadequate core cooling. The licensee has taken the position that such instrumentation is not cost effective at an estimated cost of $1 million. The staff review of the licensee PRA (Appendix D) has led the staff to conclude that implementation of this instrumentation would not reduce risk significantly at Big Rock Point.

5.3.20 Control of Heavy Loads

By Generic Letter 81-07 dated December 22, 1980, the staff provided several recommendations to be implemented by licensees to ensure the safe handling of heavy loads. Generic Letter 81-07, dated February 3, 1981, regarding control of heavy loads provided further staff guidance. By letters dated June 10, 1981, July 1, 1981, and September 23, 1981, the licensee responded to the generic letters. By letter dated July 2, 1982, the staff forwarded a draft Technical Evaluation Report (TER) on this issue to the licensee. The TER was prepared by Franklin Research Center (FRC) under contract to the staff. By letter dated January 28, 1983, the licensee responded to the TER, and the responses are now under staff review. The review of control of heavy loads was divided into two phases by the staff. The first phase included the staff guidance dealing with administrative controls such as safe load paths and procedures. The TER dealt with the first-phase review. Phase two of the staff review includes staff guidance on hardware modifications to systems such as the containment crane. The information already provided by the licensee addresses both phases. Phase two of the staff's review of Big Rock Point has just begun and is being conducted by FRC under staff contract. As the licensee indicated, resolution of the administrative control aspects of this issue is nearly complete. However, as indicated in the submittal of June 1, 1983 (Appendix H), the licensee anticipates that the staff may require hardware modifications to the containment crane, such as interlocks, to prevent crane travel over certain areas. The licensee indicated that several crane modifications, including interlocks, have been considered. None of the modifications were found to be cost effective.

The staff cannot draw conclusions on all possible modifications that might be identified in the second phase of the review. However, unlike at most plants, the crane must travel to all parts of the reactor deck and load area to perform various necessary tasks. Therefore, interlocks may be elaborate, and/or frequent overrides of the interlocks may be necessary (accompanied by elaborate plant procedures for overrides). Therefore, the staff believes that installation of travel interlocks on the containment crane may not significantly improve plant safety. A final determination cannot be made until the second phase of the review is completed.

5.3.21 Balance-of-Plant Quality Assurance Program

The licensee has proposed to improve plant reliability and availability by extending the quality assurance (QA) program for safety-related equipment to all plant equipment.

The licensee has ranked this issue forty-eighth. The staff agrees that an expanded QA program would benefit both safety and availability because it would tend to improve the reliability of the nonsafety (normal) systems and would add consistency that would tend to reduce the potential for making mistakes in quality control. However, these safety improvements are implied and cannot be quantified.

The licensee is currently developing such a program. Once the program development is complete, the licensee's Technical Review Group will schedule implementation.

5.3.22 Reactor Cooling Water Pressure

The reactor cooling water system (RCWS) discharges to the radioactive waste system (RWS) via the RCWS relief valves. The RCWS relief valves occasionally stick open because of pump-pressure transients during transfer of operation from the running pump to the standby pump.

The relief valves are located in a high radiation field during plant operations. To reduce personnel exposure, improve RCWS performance, and reduce RWS loads, the licensee proposed to evaluate future pressure transients.

This study has been completed and included investigation of system pressure requirements, relief-valve setpoints, maintenance and calibration procedures, and RCWS pressure transients during pump transfers.

As a result, the licensee has (1) revised the calibration interval for the relief valves, (2) changed the procedure for the weekly pump transfers to minimize the pressure surge, and (3) scheduled the installation of monitors to identify which relief valve is leaking (1985 refueling outage). On the basis of these actions, the licensee considers this issue resolved. The staff agrees.

5.3.23 Radwaste Monitor

The radioactive waste system (RWS) includes a monitor that must be backwashed to reduce solids buildup and the resultant increase in background radiation. At present, this backwashing is a manual function.

The licensee has committed to automate the backwash function to reduce the burden on the RWS. This project will be completed in 1987. The staff agrees.

5.3.24 Definition of Operability

By Generic Letter dated April 10, 1980, the staff requested that licensees review the operability requirements in plant Technical Specifications for accident mitigation systems such as emergency core cooling systems and emergency power systems. By letters dated May 31, 1983(a), and June 1, 1983 (see Appendix H), the licensee responded to the generic letter for Big Rock Point.

The licensee indicated that the Technical Specifications (1) do not include a definition of operability and (2) do include appropriate limiting conditions of operation (LCO) for the containment spray, core spray, reactor depressurization, and emergency power systems. The licensee further indicated that plant procedures do include an appropriate definition of equipment operability.

The licensee's submittals were reviewed by EG&G Idaho, Inc., under an NRC contract. The draft Technical Evaluation Report EGG-EA-6327 (July 1983) prepared by the contractor points out two unresolved issues:

(1) Technical Specifications do not include a definition of equipment operability.

(2) Technical Specifications do not provide an appropriate LCO for inoperability of both trains of a system.

Staff guidance recommends initiation of shutdown within 1 hour if both trains are inoperable. A definition of operability should be included in the Technical Specifications for Big Rock Point because the plant procedures can be changed without staff approval. The staff concludes that inclusion of the definition in the Technical Specifications would provide a significant increase in overall safety of the plant.

The staff has also concluded that an appropriate LCO for inoperability of redundant equipment should be included in the Technical Specifications. The total inoperability of any of the two trains of safety-related systems listed above should require initiation of shutdown within 1 hour. In addition, the licensee should provide operability statements for the sections of the Technical Specifications specified in Table 5.2 or provide a suitable technical justification for not providing an operability statement.

In their February 2, 1984 letter, the licensee committed to provide a definition of operability and include LCO for the multiple-train engineered safety feature systems; for the single-train systems, the definition of operability will serve as the LCO. These changes will be reflected in a proposed change to the Technical Specifications, to be submitted within 90 days of the issuance of this report.

5.3.25 Updated Design Data

The licensee has identified two projects to update plant design data.

5.3.25.1 Final Hazards Summary Report Update

10 CFR 50.71(e) requires that power reactors maintain an updated Final Hazards Summary Report (FHSR). The purpose of this requirement is to provide a current description of the plant design for use by the NRC staff and the public.

The licensee's proposed resolution of this issue is to evaluate a method of indexing existing documents (such as this IPSAR) to provide a workable substitute. The details of this plan are to be submitted by October 1985. This project will be completed in accordance with the schedule required in 10 CFR 50.71(e).

Such an indexing system could identify both detailed design information and a chronology of design. Therefore, the staff finds the licensee's proposal acceptable, provided it identifies specific evaluations (e.g., that required by Section 4.4).

5.3.25.2 Revised Drawings

The licensee is developing updated system drawings showing valve lineups to coincide with plant checkoff sheets in response to NRC Office of Inspection and Enforcement (IE) Bulletin 79-08 and Information Notice 81-15. This project is 96% complete. The staff concludes that the licensee should complete this project as part of the documentation for 10 CFR 50.71(e) but should not wait for the FHSR update (Section 5.3.25.1). At present the valve lineup checkoff sheets and systems drawings and the plant drawings and the piping and instrumentation diagrams do not agree.

The licensee has completed revisions to the piping and instrumentation diagrams and the systems drawings, which are used to control the valve lineup check sheets. However, other reference drawings have not yet been revised because they are not typically used for such procedural controls and require substantial resources. The licensee's Technical Review Group will decide what, if any, additional upgrading is necessary. The licensee should continue to resolve discrepancies identified by the senior resident inspector.

5.3.26 High Point Vents

The licensee has installed primary coolant system vents in response to NUREG-0737, Item II.B.1. However, these valves are not operational. Before these vents can be made operational, test connections, seismic supports, and operating procedures will be required by NUREG-0737 criteria. The licensee does not believe that this system is needed because:

(1) The RDS could be used to vent the pressure vessel (via the main steam lines).

(2) The likelihood of core uncovery (which is necessary to generate hydrogen) is very small.

(3) The cost is too high.

On the basis of these considerations, the staff concludes that further modifications to place the system in operation are not warranted. However, suitable test connections and seismic supports should be provided or the valves should be removed.

In their letter of February 2, 1984, the licensee committed to remove these valves at the earliest possible date.

5.3.27 Radiological Effluent Technical Specifications

In 1975, Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation To Meet the Criterion (As Low As Is Reasonably Achievable) for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," to 10 CFR 50 was promulgated. By letter dated February 19, 1976, the staff requested licensees to propose changes to the Technical Specifications to implement the requirements of Appendix I. Model Technical Specifications were also provided to licensees as generic guidance. The guidance has been revised by the staff several times. By letter dated March 17, 1976, the licensee responded to this issue and has made numerous submittals on this subject since that time. The submittals dated December 3, 1979, August 28, 1980, June 7, 1982, and September 29, 1982(b), provide the licensee's current proposed Process Control Program, Offsite Dose Calculation Manual, and changes to the Technical Specifications.

The licensee's current proposals are under review by the staff and Franklin Research Center (under contract to the staff). The format of the licensee's proposed Technical Specification changes to the Big Rock Point is vastly different from the format and level of detail provided in the staff's guidance. A preliminary screening by the staff indicates that these proposed changes meet most but not all of the staff's guidance. For example, they do not contain a specification on total dose (40 CFR 190), nor do they include a specification for interlaboratory comparison for the environmental monitoring program. The contractor is conducting a detailed review to identify all variances from staff guidance. After the staff receives the contractor's technical evaluation, it will determine what (if any) additional changes beyond those proposed must be made. Although these proposals have not been incorporated into the Technical Specifications, continued operation is acceptable because the licensee is operating Big Rock Point within the design objectives of Appendix I. This statement is based on a review of periodic effluent reports from the plant.

5.4 Other Pending Licensing Actions

The licensee's integrated assessment submittal dated June 1, 1983, does not address all of the pending licensing actions. The status of these additional activities are discussed below.

5.4.1 Mechanical Snubbers

In a letter dated March 23, 1981, the NRC requested that all licensees incorporate an inservice surveillance program for snubbers into plant Technical Specifications. By letter dated July 20, 1981, the licensee proposed an inservice surveillance program for mechanical snubbers at Big Rock Point. Big Rock Point has 13 mechanical snubbers on the reactor depressurization system; the plant has no hydraulic snubbers on safety systems. A review of the proposed program has been completed by the staff, and the changes to the Technical Specifications were issued in License Amendment 64.

5.4.2 Masonry Wall Design

IE Bulletin 80-11, "Masonry Wall Design," dated May 8, 1980, requested licensees to identify safety-related masonry walls and reevaluate those walls to ensure that they are properly designed. The licensee responded to the bulletin in a letter dated July 9, 1980. Also, in a letter dated November 24, 1982, the licensee responded to NRC requests for additional information on masonry wall design. It is the staff's position that all issues involving masonry walls are to be addressed by the licensee in the seismic evaluation discussed in Section 4.12.

5.4.3 Implementation of NUREG-0313, Revision 1

NRC Generic Letter 81-03 dated February 26, 1981, requested that BWR licensees review their coolant pressure boundary piping against the guidelines of NUREG-0313, Revision 1. By a letter dated June 30, 1981, the licensee responded to the generic letter and, in a letter dated May 28, 1982, provided additional information requested by the NRC on furnace sensitized safe-ends.

IE Bulletins 82-03 and 83-02 dated October 14, 1982 and March 4, 1983, respectively, discussed stress-corrosion cracking in the large piping of BWR recirculation systems. Bulletin 83-02 requested that the licensee perform certain piping inspections during the outage that started on May 13, 1983. The preliminary results of this inspection showed no evidence of cracking and were provided by a letter dated June 17, 1983, in relation to SEP Topic VI-1 (Section 4.19.2).

In addition to the IE bulletins, the staff requested additional information regarding implementation of NUREG-0313, Revision 1. The licensee responded to this request by a letter dated June 22, 1983(b).

The safety concern is that the materials of the reactor pressure boundary may be subject to corrosion-induced cracking. To resolve this concern, the staff has recommended that nuclear power plants provide augmented leak detection and inservice inspection.

The staff has completed its SEP review of the leak detection capability (Section 4.16) and found it acceptable. It has also reviewed the licensee programs for inservice inspection and found them acceptable by a letter dated June 10, 1983. Under SEP Topics V-12.A (Section 4.18) and VI-1 (Section 4.19.2), the staff has reviewed the subject of water chemistry limits and found them acceptable.

The staff is continuing its review of pipe cracking in boiling-water reactors on a generic basis. The staff concludes that the existing inspection and detection provisions at Big Rock Point are adequate. Additional protection against pipe cracking will be implemented, if necessary, on the basis of the ongoing generic review.

5.4.4 Emergency Core Cooling System Outages

NUREG-0737, Item II.K.3.17, requested licensees to submit a report of outages of emergency core cooling system (ECCS) equipment over the last 5 years. The report was also to propose changes to improve ECCS availability, if needed. By letter dated December 19, 1980(a), the licensee provided the requested information and indicated that no changes were deemed necessary. Franklin Research Center (FRC) reviewed this information under contract to the NRC. On the basis of the results of FRC's review, the staff SER, forwarded by letter dated August 5, 1983, concludes that no changes are necessary at Big Rock Point.

5.4.5 Postaccident Sampling

NUREG-0737, Item II.B.3, required licensees to provide a postaccident sampling system. Criteria were included in NUREG-0737 describing what parameters were to be sampled and how quickly the sample results should be available. In a letter dated March 31, 1981, the licensee proposed that this issue be deferred until the staff's review of his PRA was completed. By letter dated August 12, 1981, the staff accepted this proposal.

On the basis of its review of the PRA, the staff has concluded that the installation of a postaccident sampling system that meets the guidance of NUREG-0737 would not significantly improve the safety of Big Rock Point. Item II.B.3 of NUREG-0737 requested that capability be provided to sample and analyze the primary coolant and containment atmosphere under postaccident conditions. The position statement for Item II.B.3 indicates that the primary purpose of the sampling system is to provide an indication of the degree of core damage after an accident without excessive exposure to the personnel performing the sampling. The licensee argues that the high range containment radiation monitors provide such an indication. The staff's review concluded that the licensee can estimate the degree of core damage based on measurements from these monitors (letter dated October 18, 1982). Also, the installation of additional sampling systems to meet the guidance of Item II.B.3, including exposure control, would be extremely expensive and would provide very little additional data on the degree of core damage. Therefore, the staff concludes that the licensee should not be required to install additional sampling systems at Big Rock Point to meet the guidance of Item II.B.3 of NUREG-0737.

5.4.6 Anticipated Transients With Single Failure

NUREG-0737, Item II.K.3.44, requested licensees to submit an evaluation covering anticipated transients with single failure. By letter dated December 19, 1980(a), the licensee submitted the requested evaluation. The analysis submitted in this letter is similar to the information used in the licensee's PRA. The staff's evaluation of the PRA is presented in Appendix D. The staff's evaluation of the licensee's submittal has been completed; the staff's SER dated March 22, 1984, concluded that the licensee's response for Item II.K.3.44 is acceptable.

5.4.7 Compliance With 10 CFR 50.46

NUREG-0737, Item II.K.3.31, requested licensees to submit plant-specific calculations using NRC-approved models for small-break LOCAs to show compliance with 10 CFR 50.46.

The licensee has performed small-break LOCA analyses for Big Rock Point using generically accepted analytical models. In a safety evaluation issued on December 27, 1983, the staff concluded that the application and results of those analyses are acceptable.

5.4.8 Fire Damper Testing

During a fire protection inspection in August 1982, the inspectors from NRC's Region III office identified ventilation fire dampers that were not being operationally tested. The licensee agreed to test the dampers and has prepared a test procedure for fire barriers including the ventilation duct fire dampers. Region III felt that the tests should be included in the plant Technical Specifications, but the licensee felt that adequate testing could be ensured by using plant procedures.

In April 1983, Region III asked NRC for assistance on this issue. This issue has been raised at other facilities, and the staff is reviewing it on a generic basis. The need for any modification of the Technical Specifications will be determined when the staff develops a position.

5.4.9 Inservice Testing

10 CFR 50.55 requires licensees to perform inservice testing (IST) of pumps and valves in addition to conducting inservice inspections. The testing is required to be done in conformance with the ASME Code, and the licensee's program must be updated to revisions in the Code every 10 years. By letter dated January 21, 1983, the licensee submitted his IST program for the 10-year interval starting March 29, 1983. As provided for by the ASME Code and the regulations, the licensee has requested relief from a number of the Code requirements for IST. These relief requests are under review by the staff.

The review is in the early stages and no technical problems have been identified. Because of the scope of the review required, the staff has obtained contractor assistance. The review is scheduled to be completed by September 1984.

5.4.10 Relief and Safety Valve Testing

NUREG-0737, Item II.D.1, requested that licensees conduct testing to qualify relief and safety valves under transients and accident conditions. The licensee provided information including test results and plant-specific analysis in submittals dated December 19, 1980(a), July 9, 1981(a), October 1, 1981, February 5, 1982, and July 22, 1982. This information currently is under review by EG&G under a contract with the staff as part of a generic review of relief valve performance. The licensee's submittals indicated that the springs in the safety valves need to be replaced to achieve optimum performance. This work was completed during the 1983 refueling outage.

The staff believes that the licensee's corrective action is adequate to ensure reliable performance of the relief and safety valves. However, when the generic review is complete, the staff will determine whether any additional corrective actions are warranted which would substantially improve the reliability of the relief and safety valves.

5.4.11 Containment Pressure and Water Level Monitors

NUREG-0737, Item II.F.1, requested licensees to install or upgrade instrumentation to monitor variables including containment pressure and containment water level following an accident. The other instruments in Item II.F.1 were addressed earlier in Sections 5.3.7, 5.3.11, and 5.3.19 because the licensee had addressed them in the June 1, 1983, submittal as separate issues. However, the licensee has already installed the containment pressure and water level monitors and has provided information on these monitors in the following submittals: September 5, 1980, December 19, 1980(a), July 9, 1981(b), and February 5, 1982. In a letter dated April 15, 1983, the NRC requested additional information on these instruments. The licensee responded to the NRC request in letters dated June 20, 1983, and March 26, 1984. In a safety evaluation dated April 16, 1984, the staff concluded that Big Rock Point conforms with the guidelines for Item II.F.1.

5.4.12 Emergency Response Capability

NUREG-0737 presented NRC guidance on several issues related to emergency response capability:

(1) Item I.C.1, "Short-Term Accident and Procedures Review"
(2) Item I.D.1, "Control Room Design Review"
(3) Item I.D.2, "Plant Safety Parameter Display Console"
(4) Item III.A.1.2, "Upgrade Emergency Support Facilities (EOF)"
(5) Item III.A.2.2, "Meteorological Data"

Subparts and interim steps have been completed for some of these items, and other items have been found necessary during the staff's continuing review on the overall issue of emergency response capability. The NRC issued Generic Letter 82-33, "Supplement to NUREG-0737 - Requirements for Emergency Response Capability," dated December 17, 1982(b), to all licensees. That letter provided additional clarification regarding safety parameter display systems, detailed control room design review, Regulatory Guide 1.97 (Revision 2), applications of emergency response facilities, upgrading of emergency operating procedures, emergency response facilities, and meteorological data.

The letter requests licensees to

(1) prepare and implement emergency operating procedures (Section 5.3.2.2)

(2) perform a human factors review of the design of the control room and make any modifications shown to be necessary by the review (Section 5.3.2.3)

(3) design and install a console in the control room displaying the most important plant safety parameters

(4) provide indications in the control room of Type A, B, C, D, and E variables and meteorological variables listed in Regulatory Guide 1.97 (Rev. 2)

(5) provide indication in the Technical Support Center (TSC) of essential variables from Regulatory Guide 1.97 (Rev. 2)

(6) provide indication in the Emergency Operations Facility (EOF) of containment conditions and releases of radiation

(7) provide adequate staffing to perform emergency response.

The letter also asked the licensees to submit schedules and plans for meeting these requests. Final schedules were to be negotiated with the NRC's project manager for the plant. The licensee's submittal dated June 1, 1983 (see Appendix H) responded to Generic Letter 82-33.

The licensee has proposed deferring the installation of the safety parameter display system (SPDS) until the need for the system is examined in the control room design review. The licensee believes that the review will support his position that an SPDS is not necessary at Big Rock Point. If the review shows that an SPDS is necessary, the licensee will make an appropriate proposal at that time. The generic letter requests that the licensees design and install the SPDS promptly, without waiting to examine the need in the control room design review. However, the licensee points out that Big Rock Point is a small plant with far fewer systems than larger plants.

The control room is small and the existing safety indications and controls are close together already. Therefore, the licensee concludes that it is prudent to examine the need for an SPDS as a part of the control room design review. The staff agrees.

Generic Letter 82-33 requested licensees to provide certain instrumentation from Regulatory Guide 1.97, Revision 2, in the control room, the TSC, and the EOF. The generic letter requests that measurement and indication of Type A, B, C, D, and E variables and meteorological variables as specified in the regulatory guide be provided in the control room. The licensee has concluded that no additional instrumentation as specified in the regulatory guide is necessary for the Big Rock Point control room. The licensee notes that the staff's SER on SEP Topic VII-3, "Systems Required for Safe Shutdown" (forwarded by letter dated December 17, 1982(a)), concludes that "the present design is an acceptable alternative to current licensing guidelines." On the basis of its evaluation presented under Topic VII-3, the staff concludes that the additional instrumentation requested by the generic letter for the control room is not necessary for Big Rock Point. Any additional instrumentation that may be necessary to enhance the operators' ability to follow the course of an accident will evolve from the control room design review as a part of the determination of the need for an SPDS.

The generic letter requests that indication of variables necessary to perform the TSC function be provided in the TSC. The TSC at Big Rock Point is located directly outside the door of the control room; it includes the hallway along the front of the control room and the Shift Supervisor's office. Trained personnel in the TSC (Shift Supervisor, control room operator (CRO), and staff technical advisors who are CRO qualified managers) can read nearly all of the control room indicators through the windows at the front of the control room. Also, the indicators for the meteorological parameters are located right outside the control room in the TSC. Therefore, the licensee concludes that no additional indicators need to be installed in the TSC to facilitate the function of the TSC. The staff agrees.

The generic letter requests that primary indicators of the condition of the containment and radioactivity releases be provided in the EOF. The licensee proposes not to provide such indication and believes that all necessary information can be obtained by communications (such as telephone) with the TSC and control room. In view of the support function of the EOF, the staff agrees.

The generic letter also described guidance other than indication of safety parameters for the emergency response facilities (ERFs) - Technical Support Center, Operations Support Center (OSC), and Emergency Operations Facility. The guidance included aspects such as staffing, communication, security, space, radiation protection, and data analysis. The licensee believes, on the basis of information submitted in a letter dated June 1, 1981, that the current TSC, OSC, and EOF are adequate. A review team from the Office of Inspection and Enforcement will conduct an onsite review of the acceptability of the emergency response facilities for Big Rock Point after the licensee informs the staff that the ERFs are complete. The July 1983 emergency exercise indicated that additional space is required for the TSC.

The July 1983 exercise demonstrated the capability of the existing design to accomplish the emergency functions until the control room design review identifies any corrective actions that may be necessary to enhance that capability and an exercise is conducted to demonstrate the capability of the completed ERFs. With regard to the space limitations in the TSC, the licensee, in a letter dated November 23, 1983, committed to complete TSC improvements before the 1984 emergency practice drills, including the renovation of the Shift Supervisor's office. When completed, the new TSC will have approximately 50% more usable space and will be separated from the Shift Supervisor's office. This work is scheduled to be completed in May 1984.

Table 5.1 Non-SEP topic ranking summary

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.3.1	Reactor Depressurization System Valve Reliability	-	-	-	-	-
5.3.1.1	RDS Pilot Valve Leakage	No	Evaluate methods to reduce leakage	Yes	**	Yes
5.3.1.2	RDS Reliability High-Pressure Recycle System	**	Develop procedures	Yes	5/86	Yes
5.3.1.3	Full-Stroke Testing of RDS Valves	No	Evaluate test procedures	Yes	3/85	No
5.3.1.4	Position Indication of Power-Operated Relief Valves	No	None	Yes	-	No
5.3.2	Safe Shutdown	-	-	-	-	-
5.3.2.1	Alternate Shutdown System (Panel and Procedures) - Appendix R	**	Install	Yes	12/85	Yes
5.3.2.2	Upgrade Emergency Operating Procedures	No	Submit procedures	Yes	5/86	No
5.3.2.3	Control Room Design Review	**	Complete review	Yes	**	Yes

See footnotes at end of table.

Table 5.1 (Continued)

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.3.3	System Stability	-	-	-	-	-
5.3.3.1	Turbine Bypass Valve Control System	No	Evaluate cause of instability	Yes	1/85	Yes
5.3.3.2	Secondary System Instabilities	No	Modify condenser hotwell level control	Yes	12/84	Yes
5.3.4	Electrical Equipment Qualification	No	Qualify	Yes	6/84	No
5.3.5	Radiation Shielding	-	-	-	-	-
5.3.5.1	Plant Shielding - NUREG-0737, Item II.B.2	No	None	Yes	-	Yes
5.3.5.2	Control Room Habitability - NUREG-0737 - SEP Topic VI-8	No	Study seal modifications	Yes	**	Yes
5.3.5.3	Control Room Air Conditioning	No	Install air conditioner	Yes	**	No
5.3.6	Containment Integrity	-	-	-	-	-
5.3.6.1	Containment Integrated Leakage Rate Test	No	None	Yes	-	No

See footnotes at end of table.

Table 5.1 (Continued)

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.3.6.2	Containment Purge and Vent	No	(1) Install debris screens	Yes	3/85	Yes
			(2)Investigate surveillance alternatives	Yes	**	Yes
5.3.7	Hydrogen Monitoring - NUREG-0737	No	None	Yes	-	Yes
5.3.8	Scram Discharge	-	-	-	-	-
5.3.8.1	Single Channel Reset	No	None	Yes	-	No
5.3.8.2	Scram Dump Tank Valves - Lack of Redundancy	No	Evaluate alternative designs	Yes	7/84	Yes
5.3.8.3	Scram Dump Tank Level Instrumentation	No	None	Yes	-	Yes
5.3.9	Water Purification System	-	-	-	-	-
5.3.9.1	Cleanup Demineralizer Pump	No	Install bypass	Yes	**	No
5.3.9.2	Acid Line Extension	No	Provide pump system	Yes	5/84	No

See footnotes at end of table.

Table 5.1 (Continued)

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.3.9.3	Acid and Caustic Tank Problems	No	Replace components	Yes	8/84	No
5.3.10	Reactor Coolant System Isolation	No	Install valves and caps	Yes	12/84	Yes
5.3.11	Radiation Monitoring	-	-	-	-	-
5.3.11.1	Stack Gas Monitoring	Yes	Completed	Yes	-	Yes
5.3.11.2	Containment High Range Monitor	No	Completed	Yes	-	No
5.3.12	Annex and Warehouse Modification	No	Modify structures	Yes	**	No
5.3.13	Incore Detectors	Yes	Modify Technical Specifications	**	**	No
5.3.14	Fire Protection	-	-	-	-	-
5.3.14.1	Associated Circuits	No	(1) Develop procedures	Yes	12/85	Yes
			(2) Reroute emergency condenser leads	Yes	12/85	Yes
5.3.14.2	Loss of Offsite Power	No	Install radiant energy shield	Yes	12/85	Yes

See footnotes at end of table.

Table 5.1 (Continued)

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.3.15	Heating and Cooling Heat Exchanger	No	Retube	Yes	7/84	No
5.3.16	Panel C-52 Ventilation	No	Modify ventilation	Yes	12/84	No
5.3.17	Valve Reliability	No	Study pressure requirements	Yes	**	Yes
5.3.18	Recirculation Pump Trip	No	None	Yes	-	Yes
5.3.19	Instrumentation To Detect Inadequate Core Cooling	No	None	Yes	-	Yes
5.3.20	Control of Heavy Loads	**	Study alternatives	Yes	**	Yes
5.3.21	Balance-of-Plant Quality Assurance Program	No	Develop program	Yes	**	No
5.3.22	Reactor Cooling Water Pressure	No	Install monitors	Yes	12/85	No
5.3.23	Radwaste Monitor	No	Add flush timer and valve controls	Yes	12/87	No

See footnotes at end of table.

Table 5.1 (Continued)

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.3.24	Definition of Operability	Yes	Provide definition and requirements	Yes	90 days after publication of this report	No
5.3.25	Updated Design Data	-	-	-	-	-
5.3.25.1	Final Hazards Summary Report Update	No	Develop indexing system	Yes	2 years after publication of this report	No
5.3.25.2	Revised Drawings	No	Resolve discrepancies	**	**	No
5.3.26	High Point Vents	**	Remove	Yes	**	Yes
5.3.27	Radiological Effluent Technical Specifications	Yes	**	Yes	**	No
5.4.1	Mechanical Snubbers	Yes	Completed	Yes	-	No
5.4.2	Masonry Wall Design	No	**	Yes	See Section 4.12	No
5.4.3	Implementation of NUREG-0313, Revision 1	No	**	Yes	†	No
5.4.4	Emergency Core Cooling System Outages	No	None	Yes	-	No
5.4.5	Postaccident Sampling	No	None	Yes	-	Yes

See footnotes at end of table.

Table 5.1 (Continued)

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.4.6	Anticipated Transients With Single Failure	No	None	Yes	-	Yes
5.4.7	Compliance With 10 CFR 50.46	No	None	Yes	-	No
5.4.8	Fire Damper Testing	**	**	Yes	†	Yes
5.4.9	Inservice Testing	**	None	Yes	†	No
5.4.10	Relief and Safety Valve Testing	No	**	Yes	†	No
5.4.11	Containment Pressure and Water Level Monitors	-	-	-	-	-
	Containment Pressure Instrument	No	None	Yes	-	No
	Containment Water Level Monitor	No	None	Yes	-	No
5.4.12	Emergency Response Capability	-	-	-	-	-
	Meteorological Data Upgrade	No	None	Yes	-	No
	Technical Support Center	No	Enlarge TSC	Yes	5/84	No

See footnotes at end of table.

Table 5.1 (Continued)

Section No.	Title	Tech. Spec. Modifications required	Backfit requirements	Licensee agrees	Completion date	PRA* review
5.4.12	Operational Support Center	No	**	Yes	†	No
	Regulatory Guide 1.97	No	None	Yes	-	No

*See Appendix D.

**To be determined by the licensee's Technical Review Group within 90 days of the publication of this report.

†Under staff review.

Table 5.2 Technical Specifications without operability requirements

Section	Area	Comment
3.4.2, 3.4.3	Areas dealing with containment isolation	No action statement dealing with containment isolation valves found or made inoperable.
3.7	Air tests on personnel, equipment, and emergency air locks	No action statement dealing with unit operation if one or more of the locks exceeds the leak rate acceptance criteria.
4.1.2.(b)	Steam drum safety valve position monitors	States a minimum of three, and one of every two, adjacent monitors shall be operable. Also states that any of these monitor channels that become inoperable shall be made operable before the unit startup. Does this mean they can operate with all monitors inoperable? If not, an action statement is needed for whenever the minimum of three channels or adjacent monitor criteria is exceeded.
4.1.2.(b)	Emergency condenser operability	No times given for initiation of shutdown if both tube bundles in the emergency condenser are lost.
4.1.2.(b)	Shutdown cooling system	What if the system is not ready for service during power operation?
4.1.2.(b)	Reactor chemistry limits	No times given for shutdown of reactor if limits are exceeded.
5.2.2(f)	Abnormal behavior of the control rod system	No times given for shutdown of the reactor. No mention of the maximum number of inoperable control rod drives allowable. No mention of the number of accumulators allowed to be inoperable.
5.2.3	Liquid poison system	No times given for unit shutdown if the system is found to be inoperable.
6.1.5	Reactor protection system	No action statement dealing with what to do if one or more trips fail to occur during monthly surveillance test.
6.4.3(a)	Offgas system isolation and monitoring	No action statement dealing with inoperable isolation valve or failure of both monitors.

Table 5.2 (Continued)

Section	Area	Comment
6.4.3(c)	Emergency condenser vent monitors	No action statement dealing with failure of both monitors.
6.4.3(h)	Containment high range monitors (TMI item)	No action statement dealing with failure of both monitors.
6.5.4	Annual stack release for iodine 131	No action statement dealing with exceeding the limit.
11.3.1.4G	Core spray instrumentation	No mention in Table 11.3.1 of the Technical Specifications stating minimum number of operable instruments.
11.3.1.5.B	Rapid depressurization system instrumentation	No action statement dealing with less than required instruments/ channels operable as given in Table 3.5.2.b. of the Technical Specifications

6 REFERENCES

Code of Federal Regulations, Title 10, "Energy" (10 CFR) (includes General Design Criteria) and Title 40, "Protection of Environment" (40 CFR), U.S. Government Printing Office, Washington, D.C.

Commonwealth Associates Inc., "An Investigation Into the Possible Existence of Solution Cavities Beneath the Big Rock Point Nuclear Power Plant Near Charlevoix, Michigan," Feb. 1983.

Consumers Power Company, Amendment 10, "Final Hazards Summary Report for Big Rock Point," June 21, 1971.

EG&G Idaho, Inc., EGG-EA-6327, "Definition of Operable," July 26, 1983.

General Electric Topical Report NEDO-24934, "Emergency Procedure Guidelines, Revision 2," June 1982.

Harding-Lawson Associates, "Solution Features in the Traverse Group of North western Michigan."

Letter, Feb. 19, 1976, from D. L. Ziemann (NRC) to R. B. Sewell (CPCo), Subject: RE: Big Rock Point, License No. DPR-6.

---, Mar. 17, 1976, from R. B. Sewell (CPCo) to D. L. Ziemann (NRC), Subject: Big Rock Point Plant.

---, Nov. 29, 1978, from D. L. Ziemann (NRC) to D. Bixel (CPCo), Subject: Containment Purging During Normal Plant Operation.

---, Dec. 3, 1979, from D. P. Hoffman (CPCo) to D. L. Ziemann (NRC), Subject: DPR-6 and DPR-20 - Big Rock Point and Palisades Plants - Response to Request for Added Information on Proposed Technical Specifications Changes Related to Radiological Effluents.

---, Feb. 21, 1980, from H. R. Denton (NRC) to D. P. Hoffman (CPCo), Subject: Confirmatory Order.

---, Apr. 10, 1980 (generic letter) from D. G. Eisenhut (NRC) to all operating reactor licensees except Humboldt Bay, Subject: Standard Technical Specifications.

---, July 9, 1980, from D. P. Hoffman (CPCo) to J. G. Keppler (NRC), Subject: Big Rock Point Plant - Response to IE Bulletin No. 80-11 - Masonry Wall Design.

---, Aug. 28, 1980, from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC) Subject: Big Rock Point Plant - Correction to Technical Specification Submittal of December 3, 1979 (Radiological Effluents).

---, Sept. 5, 1980, from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Containment Pressure and Water Level Monitors: Submittal of Design Description.

---, Oct. 31, 1980, from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Response to Environmental Qualification of Electrical Equipment.

---, Dec. 19, 1980(a), from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Response to NUREG-0737, "Clarification of TMI Action Plan Requirements."

---, Dec. 19, 1980(b), from D. P. Hoffman (CPCO) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Revision to Technical Specifications Change Request - Containment Spray System.

---, Dec. 22, 1980 (Generic Letter 81-07), from D. G. Eisenhut (NRC) to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits, Subject: Control of Heavy Loads at Nuclear Power Plants.

---, Jan. 30, 1981, from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Revision of Environmental Qualification of Safety Related Electrical Equipment.

---, Feb. 3, 1981 (Generic Letter 81-07), from D. G. Eisenhut (NRC) to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits except Indian Point 2 and 3, Zion 1 and 2, and TMI-1, Subject: Transmitting Missing Pages From December 22, 1980 Issuance.

---, Feb. 26, 1981 (Generic Letter 81-03), from D. G. Eisenhut (NRC) to all BWR except Humboldt Bay and La Crosse, Subject: Implementation of NUREG-0313, Rev. 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping (Generic Task A-42)."

---, Mar. 23, 1981, from D. G. Eisenhut (NRC) to all SEP licensees, Subject: Technical Specification Revisions for Snubber Surveillance.

---, Mar. 30, 1981 (Generic Letter 81-18), from D. G. Eisenhut (NRC), to all licensees of operating boiling-water reactors and applicants for boiling-water-reactor operating licenses, Subject: BWR Scram Discharge System: Clarification of Diverse Instrumentation Requirement.

---, Mar. 31, 1981, from D. J. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Submittal of the Probabilistic Risk Assessment and Request for Deferral of Requirements Identified as Nonessential by the Probabilistic Risk Assessment.

---, June 1, 1981, from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Response to Post-TMI Requirements for the Emergency Operations Facility (Generic Letter 81-10).

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APPENDIX A

TOPIC DEFINITIONS FOR SEP REVIEW*

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*The topic definitions and other data appearing in this appendix were assembled in April 1977; therefore, some references to organizations and other references reflect the status of the review at that time. The basis for deletion of a topic because the review of a related TMI task, USI, or other SEP topic was identical to the review of the SEP topic was developed in May 1981. Subsequently, as a result of operating experience at Big Rock Point, Topics III-11, III-12, V-4, and VI-8 were reinstituted. Of these, only Topic V-4 was reinstituted by the staff. The others were reinstituted at the request of the licensee.

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TOPIC: II-1.A Exclusion Area Authority and Control

(1) Definition:

The establishment of the exclusion area and the licensee's control over it are reviewed at the construction permit/operating license stage. Thereafter, the licensees are required to report any changes with safety implications. The concern exists, however, that (1) the original review may not have been as thorough as currently done, or (2) changes may have occurred but have not been reported and reviewed. In particular, new activities within the exclusion area (for example, new recreational facilities or offshore oil drilling) and topographical changes (for example, changes in water levels) may need to be reviewed.

(2) Safety Objective:

To assure that appropriate exclusion area authority and control is maintained by the licensee.

(3) Status:

Selective reviews have been performed (San Onofre Nuclear Generating Station Unit 1) or are under way (Fort Calhoun) where changes in exclusion area boundary have become necessary.

(4) References:

1. Title 10, "Energy," Code of Federal Regulations, Part 100*
2. NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants - LWR Edition, "December 1975,"** Section 2.1.2

TOPIC: II-1.B Population Distribution

(1) Definition:

Population distribution in the vicinity of operating plants may have changed since the initial review was performed at the construction permit stage. Special attention should be given to new housing and commercial, military, or institutional installations established since the initial population-distribution review.

(2) Safety Objective:

New population distributions may require revision of low-population zone (LPZ) and population center to assure appropriate protection for the public by complying with the guidelines of 10 CFR Part 100. Adjustments may have

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*Hereafter referred to as 10 CFR.
**Hereafter referred to as Standard Review Plan.

to be made in emergency plans. New accident analyses may have to be performed to determine consequent conformance with 10 CFR Part 100 at new LPZ distances. Potential need for additional engineered safety features (for example, chemical sprays or better filters) exists.

(3) Status:

Has been done on a selective basis only, that is, Pilgrim Unit 1 new population center.

(4) References:

1. 10 CFR Part 100
2. Standard Review Plan, Section 2.1.3

TOPIC: II-1.C Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities

(1) Definition:

For operating plants there are three concerns:

(a) New hazards created since the facility was licensed,

(b) Hazards considered for licensing but that have expanded beyond projections or which were not reviewed against current criteria, and

(c) Hazards that were not analyzed at the licensing stage because of lack of regulatory criteria at the time.

Nearby transportation, institutional, industrial, and military facilities may be threats to safe plant operation due to:

(a) Control room infiltration of toxic gases,

(b) Onsite fires triggered by transport of combustible chemicals from offsite releases,

(c) Shock waves due to detonation of stored or transported explosives and military ordnance firing, and

(d) Onsite aircraft impact.

(2) Safety Objective:

To assure that the control room is habitable at all times and that the postulated hazards will not result in releases in excess of the 10 CFR Part 100 guidelines by disabling systems required for safe plant shutdown.

(3) Status:

Action has been taken on a selective basis only, for example, curbing of military air activity in the vicinity of the Big Rock Point Plant. Liquid natural gas (LNG) hazards at Calvert Cliffs are under review. The review of older plants did not consider offsite hazards in detail (for example, aircraft traffic in the vicinity).

(4) Reference:

Standard Review Plan, Sections 2.2.1 and 2.2.2

TOPIC: II-2.A Severe Weather Phenomena

(1) Definition:

Safety-related structures, systems, and components should be designed to function under all severe weather conditions to which they may be exposed. Meteorological phenomena to be considered include tornadoes, snow and ice loads, extreme maximum and minimum temperatures, lightning, combinations of meteorology and air-quality conditions contributing to high corrosion rates, and effects of sand and dust storms.

(2) Safety Objective:

To assure that the designs of safety-related structures, systems, and components reflect consideration of appropriate extreme meteorological conditions and severe weather phenomena. This effort would identify deficiencies in designs and/or operation that may contribute to accidental releases of radioactivity to the atmosphere resulting in doses to the public in excess of 10 CFR Part 100 or Part 20 guidelines (as appropriate to the design of the component or system).

(3) Status:

Generic studies have been initiated to develop guidelines for extreme temperatures and lightning, and to the review the current Branch Positions on snow loads. Estimated completion dates are 6/1/78 or later.

(4) References:

1. 10 CFR Part 100 or Part 20
2. Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants"
3. Standard Review Plan, Section 2.3.1
4. Branch Technical Position, "Winter Precipitation Loads," March 24, 1975
5. Inquiry by Chairman Rowden Concerning Lightning Protection, July 9, 1976
6. 10 CFR Part 50

TOPIC: II-2.B Onsite Meteorological Measurements Program

(1) Definition:

To review the onsite meteorological measurements program to determine the extent that the licensee complies with 10 CFR Part 50, Appendix E and Appendix I.

(2) Safety Objective:

To assure that adequate meteorological instrumentation to quantify the offsite exposures from routine releases is available and maintained.

(3) Status:

Onsite meteorological measurements programs are being reviewed as a part of the Appendix I evaluations.

(4) References:

1. 10 CFR Part 50, Appendix E and Appendix I
2. Regulatory Guide 1.97, Rev. 1, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident"
3. Regulatory Guide 1.23, "Onsite Meteorological Programs"
4. Standard Review Plan, Section 2.3.3

(5) Basis for Deletion (Related TMI Task, Unresolved Safety Issue (USI), or Other SEP Topic):

(a) TMI Action Plan Task II.F.3, "Instrumentation for Monitoring Accident Conditions" (NUREG-0660)

Task II.F.3 requires that appropriate instrumentation be provided for accident monitoring with expanded ranges and a source term that considers a damaged core capable of surviving the accident environment in which it is located for the length of time its function is required. Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," issued December 1980, contains the required meteorological instrumentation to quantify the offsite exposure.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term" (NUREG-0660)

Task III.A.1 requires the evaluation of 10 CFR Part 50, Appendix E, backfit requirements in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." Backfit requirements include review of the Onsite Meteorological Measurement Program.

The evaluations required by Tasks II.F.3 and III.A.1 are identical to SEP Topic II-2.B; therefore, this SEP topic has been deleted.

TOPIC: II-2.C Atmospheric Transport and Diffusion Characteristics for Accident Analysis

(1) Definition:

To review the atmospheric transport and diffusion characteristics assumed to demonstrate compliance with the 10 CFR 100 guidelines with respect to plant design, control room habitability, and doses to the public during and following a postulated design-basis accident. This effort would examine the assumptions for:

(a) Effects of explosive concentrations from onsite or offsite releases of hazardous material for consideration in structural design,

(b) Calculation of relative concentration (x/Q) values for releases of radioactivity and toxic chemicals for consideration in control room habitability, and

(c) Calculations of doses to the public resulting from releases of radioactivity to the atmosphere during and following a postulated design-basis accident.

This effort is considered necessary because most original reviews were performed using the assumptions provided in Regulatory Guides 1.3 and 1.4 which have been found to be generally nonconservative based on evaluation of over 50 sites with actual meteorological observations.

(2) Safety Objective:

To assure that the atmospheric transport and diffusion characteristics originally assumed to demonstrate compliance with the 10 CFR 100 guidelines are appropriate, considering additional onsite meteorological data and results of recent atmospheric diffusion experiments.

(3) Status:

A review of long-term (annual average) atmospheric transport and diffusion characteristics is ongoing for Appendix I evaluations independent of the SEP effort. A study has also recently been performed by the Hydrology-Meteorology Branch for the Division of Operating Reactors for review of the meteorological assumptions for estimating control room dose consequences resulting from post-LOCA purges through tall stacks.

(4) References:

1. 10 CFR Part 20
2. 10 CFR Part 50, Appendix A and Appendix I
3. 10 CFR Part 100
4. Regulatory Guides
   1.3, "Assumption Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors"
   1.4, "Assumptions Used for Evaluating the Potential Radiologcal Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors"
5. Standard Review Plan, Sections 2.3.4, 6.4, 2.2.1, 2.2.2, and 2.2.3

TOPIC: II-2.D Availability of Meteorological Data in the Control Room

(1) Definition:

Data from the onsite meteorological program should be available in the control room.

(2) Safety Objective:

To assure that the lincensee has appropriate meteorological logical data displayed in the control room to assess conditions during and following an accident to allow for (1) early indication of the need to initiate action necessary to protect portions of the offsite public and (2) an estimate of the magnitude of the hazard from potential or actual accidental releases.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 50, Appendix E and Appendix I
2. Regulatory Guide 1.97, Rev. 1, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident"
3. Regulatory Guide 1.23, "Onsite Meteorological Programs"
4. Standard Review Plan, Section 2.3.3

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) TMI Action Plan Task II.F.3, "Instrumentation for Monitoring Accident Conditions" (NUREG-0660)

Task II.F.3 requires that appropriate instrumentation be provided for accident monitoring with expanded ranges and a source term that considers a damaged core capable of surviving the accident environment in which it is located for the length of time its function is required. Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," issued December 1980, contains the required meteorological instrumentation to quantify the offsite exposure.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term" (NUREG-0660)

Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term," requires the evaluation of 10 CFR Part 50, Appendix E backfit requirements in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." Backfit requirements include review of the Onsite Meteorological Measurement Program.

(c) <u>TMI Action Plan Task I.D.1, "Control Room Design Reviews" (NUREG-0660)</u>

Task I.D.1, "Control Room Design Reviews," requires that operating reactor licensees and applicants for operating licenses perform a detailed control room design review to identify and correct design deficiencies. This review will include an assessment of control room layout, the adequacy of the information provided, the arrangement and identification of important controls and instrumentation displays, the usefulness of the audio and visual alarm systems, the information recording and recall capability, lighting, and other considerations of human factors that have an impact on operator effectiveness.

The evaluations required by Tasks II.F.3, III.A.1, and I.D.1 are indentical to SEP Topic II-2.D; therefore, this SEP topic has been deleted.

<u>TOPIC</u>: II-3.A Hydrologic Description

(1) <u>Definition</u>:

Hydrologic considerations are the interface of the plant with the hydrosphere, the identification of hydrologic causal mechanisms that may require special plant design or operating limitations with regard to floods and water supply requirements, and the identification of surface- and groundwater uses that may be affected by plant operation.

These hydrologic considerations may have changed since they were reviewed at the licensing stage. A review of such changes, if any, should be performed including an assessment of their impact on the plants.

(2) <u>Safety Objective</u>:

To assure that the designs of safety-related structures, systems, and components reflect consideration of appropriate hydrologic conditions, and to identify deficiencies in designs and/or operations that could contribute to accidental radioactive releases.

(3) <u>Status</u>:

No work currently being done on this subject for operating plants.

(4) <u>References</u>:

1. 10 CFR Parts 20, 50, and 100
2. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
3. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
4. Standard Review Plan, Section 2.4.1

TOPIC: II-3.B Flooding Potential and Protection Requirements

(1) Definition:

If the potential for floods exists and protection is required, the type of protection (sand bags, flood doors, bulkheads, and so forth) will be reviewed to assure that equipment is available and that provisions have been made to implement the required protection.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against floods.

(3) Status:

Flooding protection requirements were reviewed on selected operating plants during the winter of 1976 due to the potential for flooding caused by ice accumulation and predictions for abnormally high spring runoff for some areas.

(4) References:

1. 10 CFR Parts 50 and 100
2. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
3. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
4. Standard Review Plan, Section 2.4.10

TOPIC: II-3.B.1 Capability of Operating Plants To Cope With Design-Basis Flooding Conditions

(1) Definition:

Protection against postulated floods is accomplished, if necessary, by "hardening" the plant and by implementing appropriate technical specifications and emergency procedures.

These technical specifications and flood emergency procedures need to be reviewed for plants licensed prior to 1972 to establish the degree of conformance with current criteria. Flooding criteria used for the design of older plants are not known.

(2) Safety Objective:

Same as II-3.B

(3) Status:

Same as II-3.B

(4) References:

1. 10 CFR Part 100
2. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
3. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
4. Standard Review Plan, Sections 2.4.3, 2.4.4, 2.4.5, and 2.4.7

TOPIC: II-3.C Safety-Related Water Supply (Ultimate Heat Sink [UHS])

(1) Definition:

To determine the adequacy of onsite water sources with respect to providing safety-related water during emergency shutdown and maintenance of safe shutdown. The location and inventory of safety-related water sources and the meteorological conditions to be used in evaluating both temperature and inventory of the sources should be established. Considerations of ice, low water, leak potential, and underwater dams should be included. In most cases, plants operating prior to 1973 will have to be reviewed to establish the degree of conformance with current criteria. Prior to the issuance of Regulatory Guide 1.27 in 1973, the Standard Format and Content (now Regulatory Guide 1.70) provided the only guidelines to prospective applicants on UHS requirements. Since compliance was not required and hydrologic and meteorologic criteria had not been established, usually only minimal data were provided.

(2) Safety Objective:

To assure an appropriate supply of cooling water during normal and emergency shutdown procedures.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 100
2. Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants"
3. Standard Review Plan, Sections 2.4.11 and 9.2.5

TOPIC: II-4 Geology and Seismology

(1) Definition:

Prior to the adoption of Appendix A to 10 CFR Part 100 in 1973, the Standard Format provided the only guidelines to prospective applicants regarding the type of geologic and seismic information needed by the Atomic Energy Commission staff. The applicant, because compliance with Regulatory Guide 1.70 was not required, usually provided only minimal data. Therefore, a re-review of plants licensed prior to 1973 is needed in order to determine the adequacy of the plant design with respect to geologic and seismologic phenomena such as earthquakes, landslides, ground collapse, and liquefaction.

The review will also include ground motion and surface faulting and will establish the ground-motion values and foundation conditions to be input into the structural reevaluation for seismic loads. (It is possible that some of the older plants would require assessing only the effects of new geologic and seismic discoveries on the site safety and the resulting design acceleration and/or the response spectra.)

(2) Safety Objective:

To assure that accidents (for example, loss-of-coolant accident) do not occur and that plants can safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

Selected plants are undergoing reevaluation of geology and seismology (San Onofre Nuclear Generating Station Unit 1 and Humboldt Bay). A plan for reevaluating operating plants was developed in 1975-76 but has not been implemented pending formation of the Systematic Evaluation Program.

(4) References:

1. Standard Review Plan, Sections 2.5.1, 2.5.2, 2.5.3, 2.5.4, and 2.5.5
2. 10 CFR Part 100, Appendix A

TOPIC: II-4.A Tectonic Province

(1) Definition:

This subtopic covers a specific area within the major topic Geology and Seismology. Its purpose is to reassess the tectonic province for operating plants based on more current knowledge. (A tectonic province is a region characterized by a relative consistency of the geologic structural features contained within. Tectonic provinces are used operationally as regions within which risk from earthquakes not associated with tectonic structures or faults is considered uniform. Usually the largest historical earthquake not associated with a specific structure can be assumed to occur anywhere within the same province.)

(2) Safety Objective:

To assure that plants can be safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

The Geosciences Branch is currently attempting to delineate the boundaries of specific tectonic provinces (estimated completion date, fall 1977). The Site Safety Standards Branch is attempting to revise Appendix A to 10 CFR Part 100 so that the definition of tectonic province will more closely conform to its operational use (estimated completion date, 1978). We currently accept such provinces as generally proposed by King, Rogers, or Eardley. Limited subdivision of these provinces has been allowed based on thorough geological and seismic analyses.

(4) References:

1. 10 CFR Part 100, Appendix A
2. King, P. B., Tectonic Map of North America; Washington, D.C., U.S. Geological Survey, 1969
3. Rogers, John, The Tectonics of the Appalachians, N.Y., Wiley-Interscience, 271 p, 1970
4. Eardley, A. H., "Tectonic Divisions of North America," Bulletin of the American Association of Petroleum Geologists, 35: 2229-2237, 1951

TOPIC: II-4.B Proximity of Capable Tectonic Structures in Plant Vicinity

(1) Definition:

This subtopic covers a specific area within the major topic Geology and Seismology. Its purpose is to determine the expected shaking characteristics at a plant site from known capable faults. The ground motion associated with an earthquake generated by a capable fault or a tectonic structure may be greater than that associated with earthquakes in the same tectonic province not related to the structure.

(2) Safety Objectives:

To assure that plants can be safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 100, Appendix A
2. Standard Review Plan, Section 2.5.2
3. Regulatory Guide 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants"

TOPIC: II-4.C Historical Seismicity Within 200 Miles of Plant

(1) Definition:

Determination of the safe shutdown earthquake (SSE) is made with consideration of past seismicity in the vicinity of the plant. However, there is sometimes disagreement or inconsistency in reporting older earthquakes in the literature. Current high seismicity may also indicate possible hidden tectonic features.

The historical seismicity within 200 miles of the plants will be reviewed including all earthquakes of Richter magnitude greater than 3.0 or of Modified Mercalli intensity greater than III. Association with tectonic features and provinces should be included.

(2) Safety Objective:

To assure that the SSE is compatible with past seismicity in the area.

(3) Status:

No work currently being done in this subject for operating reactors.

(4) References:

1. Richter, C. F., Elementary Seismology, W. H. Freeman and Company, San Francisco, Calif., 1958
2. 10 CFR Part 100, Appendix A

TOPIC: II-4.D Stability of Slopes

(1) Definition:

Overstressing a slope may cause sudden failure with rapid displacement or shear strain which may damage safety-related structures. The possibility of movement is evaluated by comparing forces resisting failure to those causing failure. An assessment of this ratio should be made to determine the safety factor.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against failure of natural or man-made slopes.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Section 2.5.5
2. 10 CFR Part 100, Appendix A
3. Naval Facilities Engineering Command, NAVFAC DM-7, "Design Manual - Soil Mechanics, Foundations, and Earth Structures."

TOPIC: II-4.E Dam Integrity

(1) Definition:

Dam integrity is the ability of a dam to safely perform its intended functions. These functions would normally include remaining stable under all conditions of reservoir operation, controlling seepage to prevent excessive uplifting water pressures or erosion of soil materials, and providing sufficient freeboard and outlet capacity to prevent overtopping.

(2) Safety Objective:

To assure that adequate margins of safety are available under all loading conditions and uncontrolled releases of retained liquid are prevented.

For many projects an important consideration is the necessity of assuring that an adequate quantity of water is available in times of emergency.

(3) Status:

Additional guidance on assuring the integrity of dams is currently being developed by the Office of Standards Development in Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated With Nuclear Power Plants," and through the geotechnical engineering service contract with the U.S. Army Corps of Engineers on design of structures such as ultimate heat sinks.

(4) References:

1. Standard Review Plan, Section 2.5.6
2. 10 CFR Part 100, Appendix A
3. U.S. Army Corps of Engineers, EM 1110-2-1902, "Engineering and Design Stability of Earth and Rock-Fill Dams," Office of Chief of Engineers, 1970
4. U. S. Army Corps of Engineers, EM 1110-2-2300, "Earth and Rock-Filled Dams General Design and Construction Considerations," 1971
5. Regulatory Guide 3.11, "Design, Construction, and Inspection of Embankment Retention Systems for Uranium Mills"

TOPIC: II-4.F Settlement of Foundations and Buried Equipment

(1) Definitions:

Structural loads develop pressures in compressible strata which are not equivalent to the original geostatic pressures. Settlement and differential settlement should be evaluated.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against excessive settlement.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Section 2.5.4
2. 10 CFR Part 100, Appendix A
3. Naval Facilities Engineering Command, NAVFAC DM-7, "Design Manual - Soil Mechanics, Foundations, and Earth Structures"

TOPIC: III-1 Classification of Structures, Components, and Systems (Seismic and Quality)

(1) Definition:

Plant structures, systems, and components that are required to withstand the effects of a safe shutdown earthquake and remain functional should be classified as Seismic Category I. Systems and components important to safety should be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Review the classification of structures, systems, and components important to safety to assure they are of the quality level commensurate with their safety function.

(2) Safety Objective:

To assure that structures, systems, and components will fullfill their intended safety functions in accordance with design requirements. To assure that structures, systems, and components necessary for safety will withstand the effects of the designated safe shutdown earthquake and will remain functional.

(3) Status:

There is currently no Division of Operating Reactors activity to confirm the classification of structures, components, and systems important to safety of operating reactors.

(4) References:

1. Standard Review Plan, Section 3.2.1
2. Standard Review Plan, Section 3.2.2
3. Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants"
4. Regulatory Guide 1.29, "Seismic Design Classification"

TOPIC: III-2 Wind and Tornado Loadings

(1) Definition:

Review the capability of the plant structures, systems, and components to withstand design wind loadings in accordance with 10 CFR 50, Appendix A. The review includes the following: (A) Design Wind Protection; (B) Tornado Wind and Pressure Drop Protection; (C) Effect of Failure of Structures Not Designed for Tornado on Safety of Category I Structures, Systems and Components; (D) Tornado Effects on Emergency Cooling Ponds.

(2) Safety Objective:

To assure that Category I structures, systems, and components are adequately designed for tornado winds and pressure drop, that any damage to structures not designed for tornado-generated forces will not endanger Category I structures, systems, and components, and that tornado winds will not prevent the water in the cooling ponds from acting as a heat sink.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 2
2. Standard Review Plan, Sections 3.3, 3.8, and 9.2.5
3. Regulatory Guides
   1.76, "Design Basis Tornado for Nuclear Power Plants"
   1.117, "Protection of Nuclear Plants Against Industrial Sabotage"

TOPIC: III-3.A Effects of High Water Level on Structures

(1) Definition:

If the high water level for the plant is reevaluated and found to be above the original design basis, then review the ability of the plant structures to withstand this water level.

(2) Safety Objective:

To provide assurance that floods or high water level will not jeopardize the structural integrity of the plant seismic Category I structures and that seismic Category I systems and components located within these structures will be adequately protected.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2
2. Standard Review Plan, Sections 2.4, 3.4, and 3.8
3. Regulatory Guides
   1.59, "Design Basis Floods for Nuclear Power Plants"
   1.102, "Flood Protection for Nuclear Power Plants"

TOPIC: III-3.B Structural and Other Consequences (e.g., Flooding of Safety-Related Equipment in Basements) of Failure of Underdrain Systems

(1) Definition:

Some plants rely on underdrain systems to limit the water table elevation at the plant to a safe level. Review underdrain systems of those facilities in which they are used.

(2) Safety Objective:

To assure that the integrity of underdrain systems is maintained because a failure could lead to a rise in water table elevation which, in turn, could jeopardize the integrity of structures or the safety equipment within such structures.

(3) Status:

The structural consequences of the failure of underdrain systems were thoroughly reviewed during the construction-permit review of Douglas Point Units 1 and 2 and Perry Units 1 and 2. There are no ongoing reviews of this topic for operating facilities.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2
2. Standard Review Plan, Sections 2.4.13, 3.4, and 3.8

TOPIC: III-3.C Inservice Inspection of Water Control Structures

(1) Definition:

Review the adequacy of the inservice inspection program of water control structures for operating plants to assure conformance with the intent of Regulatory Guide 1.127.

(2) Safety Objective:

To assure that water control structures of a nuclear power facility (for example, dams, reservoirs, and conveyance facilities) are adequately inspected and maintained so as to preclude their deterioration or failure which could result in flooding or in jeopardizing the integrity of the ultimate heat sink for the facility.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) Reference:

Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated With Nuclear Power Plants"

TOPIC: III-4.A Tornado Missiles

(1) Definition:

Plants designed after 1972 have been consistently reviewed for adequate protection against tornadoes. The concern exists, however, that plants reviewed prior to 1972 may not be adequately protected, in particular, those reviewed before 1968 when Atomic Energy Commission criteria on tornado protection were developed.

An assessment of the adequacy of a plant to withstand the impact of tornado missiles would include:

(a) Determination of the capability of the exposed systems, components, and structures to withstand key missiles (including small missiles with penetrating characteristics and larger missiles which result in an overall structural impact),

(b) Determination of whether any areas of the plant require additional protection.

The systems, structures, and components required to be protected because of their importance to safety are identified in Regulatory Guide 1.117.

(2) Safety Objective:

To assure that those structures, systems, and components necessary to ensure:

(a) The integrity of the reactor coolant pressure boundary,

(b) The capability to shut down the reactor and maintain it in a safe shutdown condition, and

(c) The capability to prevent accidents which could result in unacceptable offsite exposures,

can withstand the impact of an appropriate postulated spectrum of tornado-generated missiles.

(3) Status:

The Regulatory Requirements Review Committee (RRRC) has approved case-by-case rereviews of plants against criteria in Regulatory Guide 1.117, which establishes the systems, structures, and components required to be protected against tornado missiles. This rereview was deferred pending the formation of the SEP.

The RRRC is in the process of rereviewing Standard Review Plan, Section 3.5.1.4, which establishes appropriate missiles and impact velocities for new applications.

Electric Power Research Institute (EPRI) has missile research in progress.

(4) References:

1. Standard Review Plan, Section 3.5.1.4
2. Regulatory Guide 1.117, "Tornado Design Classification"

TOPIC: III-4.B Turbine Missiles

(1) Definition:

A number of nonnuclear plants and one nuclear plant (Shippingport) have experienced turbine disk failures. Rancho Seco has had chemistry problems leading to sodium deposits which caused stress-corrosion cracking of disks. Failure of turbine disks and rotors can result in high energy missiles which have the potential for resulting in plant releases in excess of 10 CFR 100 exposure guidelines.

Two areas of concern should be considered:

(a) Design overspeed failures - material quality of disk and rotor, inservice inspection for flaws, chemistry conditions leading to stress-corrosion cracking, and

(b) Destructive overspeed failures - reliability of electrical overspeed protection system, reliability and testing program for stop and control valves, inservice inspection of valves.

The focus of the review would be on turbine disk integrity and overspeed protection, including stop, intercept, and control valve reliability.

(2) Safety Objective:

To assure that all the structures, systems, and components important to safety (identified in Regulatory Guide 1.117) have adequate protection against potential turbine missiles either by structural barriers or a high degree of assurance that failures at design (120%) or destructive (180%) overspeed will not occur.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute (EPRI) has missile research in progress.

(4) References:

1. Regulatory Guides
   1.115, "Protection Against Low Trajectory Turbine Missiles"
   1.117, "Tornado Design Classification"
2. Standard Review Plan, Section 3.5.1.3

TOPIC: III-4.C Internally Generated Missiles

(1) Definition:

Review the probability of missile generation and the extent to which safety-related structures, systems, and components are protected against the effects of potential internally generated missiles (including missiles generated inside or outside the containment).

(2) Safety Objective:

To provide assurance that the integrity of the safety-related structures, systems, and components will not be impaired and that they may be relied on to perform their safety functions following any postulated internally generated missile.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute (EPRI) has missile research in progress.

(4) Reference:

Standard Review Plan, Sections 3.5.1.1 and 3.5.1.2

TOPIC: III-4.D Site-Proximity Missiles (Including Aircraft)

(1) Definition:

Review the extent to which safety-related structures, systems, and components are protected against the effects of missiles postulated in Topic II-1.C, including postulated aircraft crashes and resulting fires.

(2) Safety Objective:

To provide assurance that the integrity of the safety-related structures, systems, and components will not be impaired and that they will perform their safety functions in the event of a site-proximity missile.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute has missile research in progress.

(4) Reference:

Standard Review Plan, Sections 3.5.1.5, 3.5.1.6, 3.5.2, and 3.5.3

TOPIC: III-5.A Effects of Pipe Break on Structures, Systems, and Components Inside Containment

(1) Definition:

Review the licensee's break and crack location criteria and methods of analysis for evaluating postulated breaks and cracks in high and moderate energy fluid system piping inside containment. The review includes consideration of compartment pressurization, pipe whip, jet impingement, environmental effects, and flooding. Regulatory Guide 1.46 does not require that cracks be postulated inside containment. However, the recent proposed revision to Standard Review Plan, Section 3.6.2, "Determination of Break Locations and Dynamic Effects Associated With the Postulated Rupture of Piping," recommends that cracks be postulated inside containment. Old and current plants are not postulating cracks.

(2) Safety Objective:

To assure that the integrity of structures, systems, and components relied upon for safe reactor shutdown or to mitigate the consequences of a postulated pipe break is maintained.

(3) Status:

This program has not been started for facilities licensed prior to about early 1974. Subsequent to that date, this topic was included in the operating-license review and has been completed for later facilities.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 4
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. Standard Review Plan, Sections 3.6.2 and 3.8
4. Regulatory Guides
   1.46, "Protection Against Pipe Whip Inside Containment"
   1.29, "Seismic Design Classification"

TOPIC: III-5.B Pipe Break Outside Containment

(1) Definition:

Review the licensee's break and crack location criteria and methods of analysis for evaluating postulated breaks and cracks in high and moderate energy fluid system piping located outside containment. The review includes consideration of compartment pressurization, pipe whip, jet impingement, environmental effects, and flooding.

(2) Safety Objective:

To assure that pipe breaks would not cause the loss of needed functions of safety-related systems, structures, and components and to assure that the plant can be safely shut down in the event of such breaks.

(3) Status:

This task is complete for all operating plants with the exception of three plants for which the review is in progress.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 4
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. Standard Review Plan, Section 3.6.1
4. Regulatory Guides
   1.46, "Protection Against Pipe Whip Inside Containment"
   1.29, "Seismic Design Classification"
5. Standard Review Plan, Branch Technical Position MEB 3-1, "Postulated Break and Leakage Locations in Fluid System Piping Outside Containment"
6. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) Issue 3-25
7. Standard Review Plan, Section 3.6.2

TOPIC: III-6 Seismic Design Considerations

(1) Definition:

Review and evaluate the original plant design criteria in the following areas: Seismic Input, Analysis and Design Criteria, Qualification of Electrical and Mechanical Equipment, Seismic Instrumentation, Seismic

Categorization, and the effect of failure of non-Category I structures on the safety of Category I structures, systems, and components.

(2) Safety Objective:

To ensure the capability of the plant to withstand the effect of earthquakes.

(3) Status:

Humboldt Bay and San Onofre plants are currently undergoing seismic review. Technical Assistance Contracts:

(a) Seismic Conservatism (Lawrence Livermore Laboratory)
(b) Elasto-Plastic Seismic Analysis (Lawrence Livermore Laboratory)
(c) Seismic Review of Operating Plants (Newmark)

(4) References:

1. Standard Review Plan, Sections 2.5, 3.7, 3.8, 3.9, and 3.10
2. Regulatory Guides
   1.12, "Instrumentation for Earthquakes"
   1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants"
   1.61, "Damping Values for Seismic Design of Nuclear Power Plants"
   1.92, "Combining Modal Responses and Spatial Components in Seismic Response Analysis"
   1.122, "Development of Flood Design Spectra for Seismic Design of Floor-Supported Equipment or Components"

TOPIC: III-7.A Inservice Inspection, Including Prestressed Concrete Containments With Either Grouted or Ungrouted Tendons

(1) Definition:

Review licensee's inspection program for all Category I structures including steel, reinforced concrete, and prestressed concrete containments. The program should include investigations for possible corrosion and cracking of steel containments, excessive cracking of concrete structures, lift-off tests of tendons, periodic testing of prestressing tendons for containments with grouted tendons, and possible deterioration of prestressed containments.

(2) Safety Objective:

To assure that the licensee's inspection program will detect any damaging deterioration of the structures and that they will be capable of performing as required by 10 CFR 50, Appendix A.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A
2. Standard Review Plan, Section 3.8
3. Regulatory Guides
   1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures"
   1.90, "Inservice Inspection of Prestressed Concrete Containment Structures With Grouted Tendons"

TOPIC: III-7.B Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria

(1) Definition:

Review the design codes, design criteria, and load combinations for all Category I structures (that is, containment, structures inside containment, and structures outside containment).

(2) Safety Objective:

To provide assurance that the plant Category I structures will withstand the NRC specific design conditions without impairment or structural integrity or the performance of required safety functions.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2 and 4
2. Standard Review Plan, Section 3.8

TOPIC: III-7.C Delamination of Prestressed Concrete Containment Structures

(1) Definition:

Review the design of prestressed concrete containment structures to assess the likelihood of delamination occurring in the shell walls or dome and to evaluate the consequences, if any.

(2) Safety Objective:

To assure that the licensee's design and construction methods have provided a structure which will maintain its integrity and will perform its intended function. Delaminations (internal cracking of concrete in planes roughly parallel to the surface) could possibly reduce the capability of the concrete to withstand compression.

(3) Status:

This review applies to all plants with prestressed concrete containments. A delamination occurred in the domes of the Turkey Point and Crystal River prestressed concrete containments. No evidence of such occurrences have been reported at other plants; however, no specific inspections have been made for any delaminations. It is not clear if the Structural Integrity Test or the existing inservice inspection programs would discover the existence of any delaminations.

(4) References:

Safety Evaluation Reports for Turkey Point (Docket No. 50-250/251) and Crystal River (Docket No. 50-302)

TOPIC: III-7.D Containment Structural Integrity Tests

(1) Definition:

Review the licensee's structural integrity testing procedure to ensure compliance with the requirements of 10 CFR 50, Appendix A.

(2) Safety Objective:

To assure that the licensee's design and constructive methods provide a structure which will safely perform its intended functions.

(3) Status:

This review applies to all plants. To our knowledge, all containments have had a structural integrity test. This opinion should be verified.

(4) References:

1. 10 CFR Part 50, Appendix A
2. Standard Review Plan, Sections 3.8.1 and 3.8.2

TOPIC: III-8.A Loose-Parts Monitoring and Core Barrel Vibration Monitoring

(1) Definition:

Inservice surveillance programs to detect loose parts and excessive motion of the main core support structure.

(2) Safety Objective:

To detect loose parts or excessive vibration before they can cause flow blockage or mechanical damage to the fuel or other safety-related components.

(3) Status:

The NRC staff currently requires applicants to describe and licensees to implement a loose-part detection program. Guidance for such a program is provided in a newly proposed Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors." The regulatory guide outlines the minimum system characteristics which the NRC staff feels are necessary for a workable system and combines this with a technical specification and reporting procedures for a complete and enforceable loose-part detection program.

The concept of detecting core barrel motion through use of excore neutron detectors is well established. A proposed regulatory guide that describes an acceptable core barrel vibration monitoring program has been temporarily placed on "hold" to permit the NRC staff and its consultants (Oak Ridge National Laboratory Inspection and Enforcement Group) time to evaluate apparently anomalous data from core barrel motion monitoring programs that are currently in service as part of the technical specification requirements for certain licensees.

(4) References:

1. Combustion Engineering, CE Report CEN-5(P), "Palisades Reactor Internals Wear Report," March 1, 1974
2. Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors"

TOPIC: III-8.B Control Rod Drive Mechanism Integrity

(1) Definition:

Review and evaluate the reliability, operability and any reported mechanical failures in control rod drives.

(2) Safety Objective:

To assure that th[illegible] and operability of control rod drives is adequately maint[illegible]hat they will be capable of normal reactor control and prompt [illegible] shutdown, if required.

(3) Status:

The Division of Operating Reactors Engineering Branch is currently evaluating the failure modes and internal component redesigns of BWR control rod drives to preclude stress corrosion and thermal fatigue cracking. There have been no reported generic failures of PWR drives.

(4) Reference:

General Electric, NEDO-21021, "Test Program for Collet Retainer Tube," June 23, 1976.

TOPIC: III-8.C Irradiation Damage, Use of Sensitized Stainless Steel, and Fatigue Resistance

(1) Definition:

Review the safety aspects that affect reactor vessel internals integrity for compliance with 10 CFR Part 50, including radiation damage, use of sensitized stainless steel, and fatigue resistance.

(2) Safety Objective:

To assure continued reactor vessel internals integrity and compliance with 10 CFR Part 50 and applicable industry Codes and Standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, currently has no review programs relating to reactor vessel internals integrity.

(4) References:

1. 10 CFR Part 50, Appendix A
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. American Society of Testing Materials, ASTM A-262-70, "Standard Recommended Practices for Detecting Susceptibility to Intergranular Attack in Stainless Steels"
4. Regulatory Guides
   1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants"
   1.44, "Control of the Use of Sensitized Stainless Steel"
   1.61, "Damping Values for Seismic Design of Nuclear Power Plants"

TOPIC: III-8.D Core Supports and Fuel Integrity

(1) Definition:

Abnormal loading conditions on the core supports and fuel assemblies due to seismic events or loss-of-coolant accidents (LOCAs) could cause fuel damage due to impact between fuel assemblies and upper- and lower-grid plates or lateral impact between fuel assemblies and the core baffle wall. The resulting damage could result in loss of coolable heat transfer geometry, make it impossible to insert control rods, or cause releases of radioactive materials due to fuel pin failure.

(2) Safety Objective:

To assure that all credible loading conditions on core supports and fuel assemblies will not result in unacceptable fuel damage or distortion.

(3) Status:

The Division of Operating Reactors is currently reviewing the dynamic loads imposed on the fuel assemblies during a LOCA. Independent analyses are being conducted by staff consultants.

(4) Reference:

American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

USI A-2 requires that an analysis be performed by licensees to assess the design adequacy of the reactor vessel supports and other structures to withstand the loads when asymmetric LOCA forces are taken into account. The staff has completed its investigation and concluded that an acceptable basis has been provided in NUREG-0609, "Asymmetric Blowdown Loads on PWR Primary Systems," January 1981, for performing and reviewing plant analyses for asymmetric LOCA loads. The structural acceptance criteria specified in NUREG-0609 are as follows:

The structural integrity of the primary system including the reactor pressure vessel, reactor pressure vessel internals, primary coolant loop, and components must be evaluated against appropriate acceptance criteria to determine if acceptable margins of safety exist. Allowable limits and appropriate loading combinations are set forth in Standard Review Plans (SRPs), which are listed in the table that follows. The staff recognizes that in some specific cases where "as-built" designs are being reevaluated for asymmetric LOCA loads, these design limits may be exceeded. Acceptance of alternative allowable limits will be based on a case-by-case evaluation of the safety margins.

Load-combination criteria in general were not addressed as part of this study. Currently the staff requires that seismic and LOCA response be combined, along with responses due to other loading as specified by the SRP. An acceptable method for combining elastically generated seismic and LOCA responses is provided in NUREG-0484. Acceptable methods for combining response generated by an inelastic LOCA analysis and elastic seismic analyses will be evaluated on a case-by-case basis.

Since USI A-2 also requires the investigation of seismic and LOCA response be combined, the evaluation required by USI A-2 is identical to SEP Topic III-8.D; therefore, this SEP topic has been deleted.

Item	SRP Section
Reactor pressure vessel	3.9.3
Reactor internals	3.9.5, 3.9.1
Primary coolant loop piping	3.9.3
ECCS piping	3.9.3
RPV, SG, pump supports	3.8.3
Biological shield wall	3.8.3
Steam-generator compartment wall	3.8.3
Neutron-shield tank	3.8.3

TOPIC: III-9 Support Integrity

(1) Definition:

Review the design, design loads, and materials integrity including corrosion and fracture toughness and the inservice inspection programs of supports and restraints including bolting for the reactor vessel, steam generator, reactor coolant pump, torus, and other Class 1, 2, and 3 safety-related components and piping systems.

(2) Safety Objective:

To assure adequate support and/or restraint of safety-related systems and components under normal and accident loads so that they will not be prevented from performing their intended functions because of support failures.

(3) Status:

The Division of Operating Reactors has ongoing programs to review component supports. Current emphasis is on primary system supports and on piping system supports and restraints (snubbers).

(4) References:

1. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
2. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Topics 3-5 and 3-43

(5) Basis for Deletion (Related TMI Task, USI, or other SEP Topic):

(a) USI A-12, "Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports" (NUREG-0510 and NUREG-0606)

The original scope of USI A-12 was the review of the steam generator and reactor coolant pump supports of pressurized water reactors.

However, the staff has expanded the review to include other support structures, such as boiling water reactor (BWR) vessel supports, BWR pump supports, pressurized water reactor (PWR) vessel supports and PWR pressurizer supports (NUREG-0577, Section 1.3). This expanded review will be undertaken in accordance with the guidance of Section 4 of NUREG-0577.

(b) USI A-7, "MARK I Containment Long-Term Program" (NUREG-0649)

Support integrity of the torus is being evaluated under USI A-7. Under this task, a short-term program that evaluated Mark I containment has provided assurance that the Mark I containment system of each operating BWR facility would maintain its integrity and functional capability during a postulated loss-of-coolant accident. A longer term program for BWR facilities, not yet licensed, is planned wherein the NRC staff will evaluate the loads, load combinations, and associated structural acceptance criteria proposed by the Mark I Owners Group prior to the performance of plant-unique structural evaluations. The Mark I Owners Group has initiated a comprehensive testing and evaluation program to define design-basis loads for the Mark I containment system and to establish structural acceptance criteria which will assure margins of safety for the containment system which are equivalent to that which is currently specified in the ASME Boiler and Pressure Vessel Code. Also included in their program is an evaluation of the need for structural modifications and/or load mitigation devices to assure adequate Mark I containment system structural safety margins.

(c) USI A-24, "Qualification of Class 1E Safety-Related Equipment" (NUREG-0371 and NUREG-0606)

Snubber operability and degradation of seals are covered under USI A-24.

(d) USI A-46, "Seismic Qualification of Equipment in Operating Plants" (NUREG-0705)

Mechanical snubbers are covered under USI A-46.

(e) SEP Topic III-6, "Seismic Design Considerations"

Snubbers are evaluated for capacity under SEP Topic III-6.

(f) SEP Topic V-1, "Compliance With Codes and Standards (10 CFR 50.55a)"

Inservice inspection requirements for supports are covered under SEP Topic V-1, which refers to 10 CFR 50.55a. SEP plants currently have surveillance Technical Specifications on snubbers.

The evaluation required by USI A-12, A-7, A-24, and A-46 and SEP Topics III-6 and V-1 is identical to the evaluation required by SEP Topic III-9; therefore, this SEP topic has been deleted.

TOPIC: III-10.A Thermal-Overload Protection for Motors of Motor-Operated Valves

(1) Definition:

The primary objective of thermal overload relays is to protect motor windings of motor-operated valves (MOVs) against excessive heating. This feature of thermal overload relays could, however, interfere with the successful functioning of a safety-related system. In nuclear plant safety system application, the ultimate criterion should be to drive the valve to its proper position to mitigate the consequences of an accident, rather than to be concerned with degradation or failure of the motor due to excess heating.

(2) Safety Objective:

To assure that (1) thermal overload protection, if provided for MOVs, should have the trip setpoint at a value high enough to prevent spurious trips due to design inaccuracies, trip setpoint drift, or variation in the ambient temperature at the installed location; (2) the circuits which bypass the thermal overload protection under accident conditions should be designed to IEEE Std. 279-1971 criteria, as appropriate for the rest of the safety-related system; and (3) in MOV designs that use a torque switch instead of a limit switch to limit the opening or closing of the valve, the automatic opening or closing signal should be used in conjunction with a corresponding limit switch and thermal overload should remain as backup protection.

(3) Status:

The staff position (Reference 1) is implemented on designs of new applications (construction permit and operating license).

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB 27, "Design Criteria for Thermal Overload Protection for Motors of Motor-Operated Valves"
2. Institute of Electrical and Electronics Engineers, IEEE Std. 279-1971, Criteria for Protection System for Nuclear Power Generating Stations"
3. Regulatory Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves"

TOPIC: III-10.B Pump Flywheel Integrity

(1) Definition:

Review the PWR reactor coolant pump flywheel inservice inspection programs of operating plants to assure that they comply with the intent of Regulatory Guide 1.14 and review reports of flywheel flaws if found by inservice inspections. (BWR reactor coolant pumps do not have flywheels.)

(2) Safety Objective:

To assure that pump flywheel integrity is maintained to prevent failure at normal operating speeds and at speeds that might be reached under accident conditions and thus preclude the generation of missiles.

(3) Status:

The inservice inspection programs for flywheels of older PWRs have not been reviewed for compliance with the intent of Regulatory Guide 1.14.

(4) Reference:

Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity"

TOPIC: III-10.C Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves

(1) Definition:

At facilities which have completed the low pressure coolant injection system (LPCIS) modification, the recirculation pump discharge valves and bypass valves are now required to close upon initiation of LPCIS. The closure of these discharge valves is necessary to isolate a pipe break in a suction line to prevent loss of cooling water by reverse flow through the recirculation pump or its bypass line and out the break.

(2) Safety Objective:

To assure effective core cooling in the event of a BWR recirculation line break on the pump suction line by closing the pump discharge valve and bypass line valve.

(3) Status:

All licensees of facilities with completed LPCIS modification have been sent letters requesting that they apply for a license amendment to incorporate technical specification surveillance requirements on recirculation pump discharge valves and bypass valves. New BWRs have the LPCIS modification and technical specification surveillance requirements.

(4) Reference:

NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) Issue 3-46, June 17, 1977

TOPIC: III-11 Component Integrity

(1) Definition:

Review licensee's criteria, testing procedures, and dynamic analyses employed to assure the structural integrity and functional operability of safety-related mechanical equipment under faulted conditions and accident loads. Included are mechanical equipment such as pumps, valves, fans, pump drives, heat exchanger tube bundles, valve actuators, battery and instrument racks, control consoles, cabinets, panels, and cable trays.

(2) Safety Objective:

To confirm the ability of safety-related mechanical equipment having experienced problems to function as needed during and after a faulted or accident condition. The capability of safety-related mechanical equipment to perform necessary protective actions is essential for plant safety.

(3) Status:

This review is not currently under way in the Divisions of Operating Reactors.

(4) References:

1. 10 CFR Part 50, Section 50.55a
2. 10 CFR Part 50, Appendix A, GDC 2, 4, 14, and 15
3. Standard Review Plan, Section 3.9.2
4. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III,
5. Regulatory Guides
   1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing"
   1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants"
6. Institute of Electrical and Electronics Engineers, IEEE Std. 344-1975, "Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations"
7. Standard Review Plan, Section 3.9.3

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-46, "Seismic Qualification of Equipment in Operating Plants" (NUREG-0606 and NUREG-0705)

The component integrity (both structural integrity and functional operability) for safety-related mechanical and electrical equipment for all operating plants including SEP plants will be addressed in this new USI (A-46).

(b) USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

The assessment of faulted loads for the primary loop is being performed under USI A-2. Furthermore, the assessment of high-energy pipe breaks considers the effect of accident loads with regard to jet impingement, pipe whip, and other reaction loads.

(c) SEP Topic III-6, "Seismic Design Considerations"

The evaluation of equipment structural integrity under seismic loads will be performed under SEP Topic III-6.

The evaluations required by USI A-46 and A-2 and SEP Topic III-6 are identical to SEP Topic III-11; therefore, this SEP topic has been deleted.

TOPIC: III-12 Environmental Qualification of Safety-Related Equipment

(1) Definition:

Safety-related electrical and mechanical equipment that is required to survive and function under environmental conditions calculated to result from a loss-of-coolant accident (LOCA) or a postulated main steam line break accident inside containment must be environmentally qualified. In addition, determine whether environment-induced failures of nonsafety-related equipment could interfere with the operation of safety equipment. Special attention should be given to the effect of beta radiation on exposed organic surfaces, such as gaskets.

(2) Safety Objective:

To assure that the mechanical and Class IE electrical equipment of safety systems has been qualified for the most severe environment (temperature, pressure, humidity, chemistry, and radiation) of design basis accidents.

(3) Status:

Westinghouse is conducting a verification program which is expected to be completed by the end of 1977 for those plants qualified to IEEE 323-1971. The Office of Nuclear Regulatory Research is sponsoring programs relating to Class IE equipment qualification, the results of which can be utilized to determine the adequacy of the equipment previously qualified.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue 25, "Qualification of Safety-Related Equipment," December 1976
2. Division of Operating Reactors, DOR Technical Activities, Category B, Item 34, "Environmental Qualifications of Safety-Related Equipment (Post LOCA)," May 1977
3. Division of Systems Safety, DSS Technical Activities, Category A, Item 33, "Qualification of Class IE Safety-Related Equipment," April 1977
4. Regulatory Guide 1.89, "Qualification of Class IE Equipment for Nuclear Power Plants"

(5) Basis for Deletion (Related TMI Task, USI, or other SEP Topic):

- USI A-24, "Qualification of Class IE Safety-Related Equipment" (NUREG-0371 and NUREG-0606)

The issue identified in Reference 1 (NUREG-0153, Item 25) and the review criteria, that is, Regulatory Guide 1.89, are identical to those specified in USI A-24. The Task Action Plan for USI A-24

(NUREG-0371) covers the environmental qualification of both electrical and mechanical safety-related equipment.

The evaluation required by USI A-24 is identical to SEP Topic III-12, therefore, this SEP topic has been deleted.

TOPIC: IV-1.A Operation With Less Than All Loops in Service

(1) Definition:

A number of BWR and PWR licensees have requested authorization to operate with one of the recirculation loops (BWR) or steam generator loops (PWR) out of service. These proposals are being reviewed generically with regard to analytical methods. Plant-specific reviews will be done to determine appropriate Technical Specification limits. Plant-specific reviews will address results of LOCA analyses using generically approved methods. Analysis of accidents (other than LOCA) and operating transients resulting from operation in the (N-1) loop mode have been reviewed on a "lead plant basis." Most of this effort has been completed. Tests have been conducted by General Electric which show that significant core flow asymmetries do not exist with single-loop operation for two-loop plants; however, there is backflow through inactive jet pumps. Therefore, for single-loop operation, modifications are necessary in trip settings which take inputs from jet pump drive flow. These will be determined on a plant-specific basis.

(2) Safety Objective:

To provide assurance that operation with less than all coolant loops in operation will not result in decreased safety margins.

(3) Status:

A combination of generic and plant-specific reviews is being performed on both BWRs and PWRs.

TOPIC: IV-2 Reactivity Control Systems Including Functional Design and Protection Against Single Failures

(1) Definition:

General Design Criterion 25 requires that the reactor protection system be designed to assure that fuel-damage limits are never exceeded in the event of any single failure of the reactivity control systems. Reactivity control systems need not be designed single failure proof, but the protection system (which is designed against single failures) should be capable of limiting fuel damage in the event of a reactivity control system single failure.

(2) Safety Objective:

To assure that for all credible reactivity control system failures, the protection system will limit fuel damage to acceptable limits.

(3) Status:

NRC has concluded that revisions to existing licenses are not warranted. Staff effort on this issue will continue at a low level.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 6, "Protection Against Single Failures in Reactivity Control Systems," December 1976.
2. Standard Review Plan, Section 15.4.3

TOPIC: IV-3 BWR Jet Pump Operating Indications

(1) Definition:

If a jet pump BWR operates with a failed jet pump, it may be impossible to reflood the core in the event of a LOCA. Some BWRs have experienced jet pump instrument sensing line failures. With a sensing line failed, it may not be possible to accurately measure core flow or to detect failure of a jet pump.

(2) Safety Objective:

To assure that the core flow can be determined. Also to assure the ability to detect a jet pump failure for a range of crack/break sizes at various locations on the pump.

(3) Status:

This issue is currently being reviewed for Dresden Units 2 and 3 and Quad Cities Units 1 and 2. The topic has generic implications for all jet pump BWR plants.

(4) References:

1. Letters from Commonwealth Edison Company to NRC, dated September 19, 1975, March 3, 1976, and June 7, 1976.
2. Letter from NRC to Commonwealth Edison Company, dated January 19, 1976.
3. Memorandum from J. H. Sniezek, NRC, to D. L. Ziemann, dated November 19, 1975.

TOPIC: V-1 Compliance With Codes and Standard (10 CFR 50.55a)

(1) Definition:

Review the licensee's inservice inspection and testing programs for Class 1, 2, and 3 pressure vessels, piping, pumps and valves and other safety-related components to assure compliance with the American Society of Mechanical Engineers (ASME) Code, Sections III and XI, as required by 10 CFR 50.55a. This review will also include review of the inservice inspection and testing program applicable to isolation condensers of the early operating BWRs.

(2) Safety Objective:

To assure that the initial integrity of components is maintained throughout service life.

(3) Status:

NUREG-0081 was completed for reactor vessels not designed to ASME Code, Section III. The Engineering Branch conducts a generic review of all plants for compliance with inspection requirements of 10 CFR 50.55a(g) and fracture toughness requirements of 10 CFR 50.55a(i). This program will continue for the life of operating reactors.

(4) References:

1. 10 CFR Part 50, Section 50.55a
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Sections III and XI
3. NUREG-0081, "Evaluation of the Integrity of Reactor Vessels Designed to ASME Code, Section I and/or VIII," July 1976
4. Memorandum from V. Stello, NRC, to B. H. Grier, October 12, 1976

TOPIC: V-2 Applicability of Code Cases

(1) Definition:

Review Code Cases currently accepted by the NRC, as indicated in Regulatory Guides 1.84 and 1.85.

(2) Safety Objective:

To assure that only those Code Cases which are acceptable to the NRC are utilized by the licensee in the design, fabrication, or repair of the plant. The use of Code Cases other than those contained in Regulatory Guides 1.84 and 1.85 are addressed on a case-by-case basis to assess their acceptability.

(3) Status:

The Engineering Branch, Division of Operating Reactors, routinely reviews design modifications and component repairs (for example, reactor vessel nozzles) to assure compliance with NRC acceptable Code Cases. The program is ongoing on an as-needed basis.

(4) References:

Regulatory Guides
1.84, "Design and Fabrication Code Case Acceptability - ASME Section III, Division 1"
1.85, "Materials Code Case Acceptability - ASME Section III, Division 1"

TOPIC: V-3 Overpressurization Protection

(1) Definition:

Inadvertent overpressurization of the primary system at temperatures below the nil ductility transition temperature may result in reactor vessel failure during heatup and pressurization. Such overpressure transients are caused by pressure surges when the primary system is water solid. The most severe transients have occurred when a charging pump starts up or inadvertent closing of a letdown valve with a charging pump running. Pressure temperature limits as a function of neutron fluence of the material at the reactor vessel beltline are specified in 10 CFR 50, Appendix G. All PWR licensees have been directed to institute interim administrative procedures to prevent damaging pressure transients and on a longer time scale to provide permanent protection which will probably include hardware changes such as high-capacity safety relief valves.

(2) Safety Objective:

To protect the primary system from potentially damaging overpressurization transients during plant pressurization and heatup.

(3) Status:

Generic review of all PWR licensee submittals is under way. Criteria for evaluation have been developed and refined by the Office of Nuclear Reactor Regulation and the Office of Nuclear Regulatory Research. An effort is being made to complete the review sufficiently early to ensure installation of mitigating systems by the end of 1977.

(4) Reference:

NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR to NRR Staff," November 1976

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-26, "Reactor Vessel Pressure Transient Protection" (NUREG-0410)

  Under USI A-26, licensees were requested to modify their systems and procedures to protect against low temperature overpressurization. All operating PWRs have made these modifications, and safety evaluation reports for the SEP plants have been issued.

  The evaluation required by USI A-26 is identical to SEP Topic V-3; therefore, this SEP topic has been deleted.

TOPIC: V-4 Piping and Safe-End Integrity

(1) Definition:

Review the safety aspects that affect BWR and PWR piping and safe-end integrity for compliance with 10 CFR Part 50, including fracture toughness, flaw evaluation, stress corrosion cracking in BWR and PWR piping, and control of materials and welding.

(2) Safety Objective:

To ensure continued piping integrity and compliance with 10 CFR Part 50 and applicable industry codes and standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, is conducting an ongoing program that includes the as-needed review of those aspects necessary to ensure the continuing integrity of piping systems important to safety including stress corrosion cracking of BWR coolant pressure boundary piping. This program will continue for the life of operating reactors.

(4) Reference:

American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section XI

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-42, "Pipe Cracks in Boiling Water Reactors" (NUREG-0510)

The scope of USI A-42 is the study of stress corrosion cracking in BWR piping. NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," is the resolution of USI A-42 and presents staff positions.

(b) USI A-10, "BWR Feedwater Nozzle Cracking and Control Rod Drive Hydraulics Return Line Nozzle Cracking" (NUREG-0649)

(c) NRR Generic Activity C-7, "PWR System Piping" (NUREG-0471)

The scope of this activity is the study of stress corrosion cracking in PWR piping. NUREG-0691, "Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," recommends the same corrective actions (pp. 2-12) proposed for BWRs in NUREG-0313, Revision 1, USI A-42.

The evaluation required by USI A-42 and Task C-7 is identical to the evaluation required by SEP Topic V-4; therefore, this SEP topic has been deleted.

TOPIC: V-5 Reactor Coolant Pressure Boundary (RCPB) Leakage Detection

(1) Definition:

Reactor primary coolant leakage detection systems are a significant means of preventing primary system boundary failure by identifying leaks before failures occur.

(2) Safety Objective:

To provide reliable and sensitive leakage detection systems to identify primary system leaks at an early stage before failures occur.

(3) Status:

This issue has been resolved for all plants which have recently received an operating license by requiring conformance to Regulatory Guide 1.45. Individual older plants have not been systematically reviewed and leakage detection systems may need upgrading on a plant-by-plant basis.

(4) References:

1. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems"
2. Standard Review Plan, Section 5.2.5

TOPIC: V-6 Reactor Vessel Integrity

(1) Definition:

Review the safety aspects that affect BWR and PWR reactor vessel and nozzle integrity for compliance with 10 CFR Part 50, including fracture toughness, neutron irradiation, evaluation of surveillance programs, operating limitations, inservice inspection and flaw evaluation, and transient analyses.

(2) Safety Ojective:

To assure continued reactor vessel integrity and compliance with 10 CFR Part 50 and applicable industry codes and standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, is conducting ongoing programs that include the periodic review of aspects necessary to ensure the continued integrity of reactor vessels. These programs include BWR feedwater and control rod drive nozzle cracking, low upper-shelf toughness, radiation effects, reactor vessel materials surveillance, and updating of operating plants' inservice inspection programs and will continue for the life of operating reactors.

(4) References:

1. NUREG-0312, "Interim Technical Report on BWR Feedwater and Control Rod Drive Return Line Nozzle Cracking," July 1977
2. 10 CFR Part 50, Appendix G
3. Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials"
4. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III, Appendix G
5. American Society of Testing Materials, ASTM E185, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels"

6. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section XI
7. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Issue 3-9, 3-21, 3-41

TOPIC: V-7 Reactor Coolant Pump Overspeed

(1) Definition:

Review the potential for reactor coolant pumps to fail because of overspeed in the unlikely event of a major loss-of-coolant accident (LOCA).

(2) Safety Objective:

To assure that, in the event of a major LOCA, a reactor coolant pump assembly is not driven to a speed which would cause structural failure of the unit and result in missiles which could increase the consequences of the LOCA. Of greatest concern are the PWR pump flywheels because of their mass and rotational energy.

(3) Status:

An indepth review of this topic was performed by the Atomic Energy Commission staff and reported to the Advisory Committee on Reactor Safeguards (ACRS) in 1973 (Reference 1). The staff concluded that, because of the small likelihood for the occurrence of a pump overspeed event that could seriously increase the consequences resulting from a LOCA (less than 10-8 per plant year), the action taken by the staff to assess this problem in a generic fashion outside the context of individual application reviews is an acceptable course to follow. A generic experimental program to be completed in 1978 by the Electric Power Research Institute is expected to provide data to verify pump model overspeed predictions.

(4) References:

1. Letter from R. C. DeYoung, NRC, to Harold G. Mangelsdorf, ACRS, August 6, 1973, transmitting "Report on Reactor Coolant Pump Overspeed During a LOCA," August 3, 1973.
2. Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity"

TOPIC: V-8 Steam Generator (SG) Integrity

(1) Definition:

Review the safety aspects affecting operation of steam generators including secondary water chemistry, tube plugging criteria, inservice inspection, possibly including a dimensional inspection for proper evaluation of denting, steam generator tube leakage, tube denting, flow-induced vibration of steam generator tubes, tube repair, and tube bundle or steam generator replacement.

(2) Safety Objective:

To ensure that acceptable levels of integrity of that portion of the reactor coolant pressure boundary made up by the steam generator are maintained in accordance with current codes, standards, and/or regulatory criteria during normal and postulated accident conditions. The integrity of the steam generator is needed to ensure that leakage following a postulated design basis accident will not result in doses to the public in excess of 10 CFR Part 100 guidelines and that the emergency core cooling systems will be able to perform their safety functions.

(3) Status:

Review of this topic is being performed by the Division of Operating Reactors (DOR). This effort will continue for the life of operating reactors.

(4) References:

1. Regulatory Guide 1.83, Rev. 1, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes"
2. Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes"
3. 10 CFR Part 50, Appendix A, GDC 30 and 32
4. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), 3-27

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-3, A-4, A-5, "Westinghouse, Combustion Engineering, and Babcock and Wilcox Steam Generator Tube Integrity" (NUREG-0649)

The definition of this topic and the references cited are covered by USI A-3, A-4, and A-5. The evaluation for USI A-3, A-4, and A-5 is identical to SEP Topic V-8; therefore, this SEP topic has been deleted.

TOPIC: V-9 Reactor Core Isolation Cooling System (BWR)

(1) Definition:

Reactor core isolation cooling (RCIC) has not been classified as a safety system. On GESSAR, for certain small breaks, GE assumed credit for RCIC as a backup for HPCI. The staff required GE to reclassify the RCIC system on the GESSAR 238 standard NSSS as a safety system.

(2) Safety Objective:

To ensure that the RCIC system is qualified as a safety system where credit is assumed in the safety analysis.

(3) Status:

GE has agreed to reclassify RCIC as a safety system on the GESSAR docket.

TOPIC: V-10.A Residual Heat Removal System Heat Exchanger Tube Failures

(1) Definition:

Residual heat removal (RHR) heat exchangers are designed to remove residual and decay heat so that the reactor can be placed in a safe cold shutdown condition and to maintain core cooling following a postulated loss-of-coolant accident. Some light-water reactors (LWRs) have a pressure control system on the cooling water piping system which maintains the pressure of the cooling water higher than the primary coolant pressure in the primary coolant side of the heat exchanger during plant cooldown operations. A leak in the tubes could result in back leakage of coolant water into the primary loop. Pressure in the cooling water side is maintained higher than that in the primary coolant side so that in the event of a tube failure there would be no leakage of radioactive fluids into the environment. Cooling water passing from the cooling water side of the heat exchanger into the primary coolant water could introduce impurities such as chlorides into the primary coolant system.

(2) Safety Objective:

To assure that impurities from the cooling water system are not introduced into the primary coolant in the event of an RHR heat exhanger tube failure.

(3) Status:

Recently there have been several RHR heat exchanger tube failures at operating BWRs. This issue has been defined as a DOR Category B Technical Activity.

TOPIC: V-10.B Residual Heat Removal System Reliability

(1) Definition:

In all current plant designs, the residual heat removal (RHR) system has a lower design pressure than the reactor coolant system (RCS). In most current designs, the system is located outside of containment and is part of the emergency core cooling system. However, it is possible for the RHR system to have different design characteristics. For example, the RHR system might have the same design pressure as the RCS, or be located inside of containment. The functional, isolation, pressure relief, pump protection, and test requirements for the RHR system are of concern in the safety review of reactor plants. Three types of RHR system designs are defined in Branch Position RSB 5-1.

On June 24, 1976, the Regulatory Requirements Review Committee approved a revision of Standard Review Plan, Section 5.4.7 requiring a capability to go from hot to cold shutdown without offsite power and that all components necessary for cooldown from hot shutdown must be designed to safety grade seismic I standards, and be operable from the control room. System must be designed to meet the single failure criterion.

(2) Safety Objective:

To ensure reliable plant shutdown capability using safety-grade equipment.

(3) Status:

Because of vendor concern over the impact of the revision, a review was conducted of three PWR plants, and as a result of this review, the staff is proposing that Branch Position RSB 5-1 be modified but that the functional requirements be retained.

(4) References:

1. Standard Review Plan, Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System"
2. Standard Review Plan, Section 5.4.7
3. Memorandum from E. G. Case, NRC, to L. V. Gossick, July 15, 1976.
4. Summary of meeting September 22, 1976, "Capability To Achieve Cold Shutdown Using Safety Grade Systems and Equipment," C. O. Thomas, Docket No. STN-50-545, October 5, 1976.

TOPIC: V-11.A Requirements for Isolation of High- and Low-Pressure Systems

(1) Definition:

Several systems that have a relatively low design pressure are connected to the reactor coolant pressure boundary. The valves that form the interface between the high- and low-pressure systems must have sufficient redundancy and interlocks to assure that the low-pressure systems are not subjected to coolant pressures that exceed design limits. The problem is complicated since under certain operating modes (for example, shutdown cooling and emergency core cooling system injection), these valves must open to assure adequate reactor safety.

(2) Safety Objective:

To assure that adequate measures are taken to protect low-pressure systems connected to the primary system from being subjected to excessive pressure which could cause failures and in some cases potentially cause a loss-of-coolant accident outside of containment.

(3) Status:

A preliminary review of a representative operating plant of each nuclear steam supply system vendor was undertaken. Each low-pressure system connected to the reactor coolant pressure boundary and penetrating the containment was examined. The investigation of a few potential areas of concern is continuing.

TOPIC: V-11.B Residual Heat Removal System Interlock Requirements

(1) Definition:

The residual heat removal (RHR) system is normally located outside of primary containment. It is an intermediate pressure system (usually 600 psia) and has motor-operated valve (MOV) isolation valves connecting it to the reactor coolant system (RCS). If the RHR system were inadvertently connected to the RCS while the RCS is at pressure, a loss-of-coolant accident (LOCA) could result with a loss of all capability of core reflooding since the coolant inventory could be lost outside of containment. To prevent inadvertent opening of the MOVs while the RCS is at pressure, an "OPEN PERMISSIVE" interlock is provided.

If the operator shuts only one of the isolation valves prior to pressurizing the RCS, there is a single valve RCS pressure boundary.

To ensure that both MOVs are shut during a startup and heatup, an "AUTO-CLOSURE" interlock is provided that closes the MOVs.

(2) Safety Objective:

To ensure that operating reactor plants are adequately protected from overpressurizing the RHR system and potentially causing a LOCA outside of containment.

(3) Status:

Several PWR plants do not have the auto closure feature on the RHR, and at least one does not have the open permissive feature. Plants should be reviewed on a case-by-case basis factoring in (1) ASME Code safety valve setting and capacity, (2) interlocks, (3) closure time of MOVs, and (4) location of RHR.

(4) References:

1. Proposed Branch Technical Position RSB-5-1, "Design Requirements of the Residual Heat Removal System"
2. Regulatory Requirements Review Committee Meeting No. 50, June 24, 1976
3. 10 CFR Part 50, Appendix A, GDC 34
4. Memorandum from J. Angelo to R. C. DeYoung, V. Stello, et al., NRC, Subject: "RP-TR Staff Meeting of February 13, 1974 Regarding the Requirements on Shutdown Cooling Systems," February 28, 1974
5. Letter from R. Boyd, NRC, to C. Eicheldinger, Westinghouse Electric Corporation, November 12, 1975
6. Letter from R. Boyd, NRC, to I. Stuart, General Electric Company, November 12, 1975
7. Letter from R. Minogue, NRC, to J. D. Geier, Illinois Power Company, July 8, 1975

TOPIC: V-12.A Water Purity of BWR Primary Coolant

(1) Definition:

Review the primary water monitoring and reactor water cleanup system capabilities, including the water purity, to determine if the maintenance of the necessary purity levels complies with Regulatory Guide 1.56. Review limits on quality control and defined provisions in the event of demineralizer breakthrough.

(2) Safety Objective:

To assure that the water purity level is acceptably low to minimize the potential for intergranular stress corrosion cracking of austenitic stainless steel piping in the reactor coolant pressure boundary of BWRs, including assuring the implementation of Regulatory Guide 1.56.

(3) Status:

Recommendations for specifying the use of additional conductivity measurements and monitoring at various locations, plus the use of pH and chloride measurements, have been submitted to the Division of Standards Development to initiate a revision of Regulatory Guide 1.56, "Maintenance of Water Purity in Boiling Water Reactors," dated June 1973. To date, a generic review of operating BWRs has not been initiated and the current regulatory guide has been implemented in the Technical Specifications of only a few operating plants.

(4) Reference:

Memorandum from R. E. Heineman, to R. B. Minogue, NRC, Subject: "Request for Revision of Regulatory Guide 1.56," 1973

TOPIC: V-13 Waterhammer

(1) Definition:

Waterhammer events have occurred in light water reactor systems. Waterhammer events increase the probability of pipe breaks and could increase the consequences of certain events such as the loss-of-coolant accident. The types of waterhammer, the vulnerable systems (for example, containment spray, service water, feedwater, and steam), and the safety significance of waterhammer have been identified and defined in a staff report of May 1977.

(2) Safety Objective:

To reduce the probability of waterhammer events that have the potential to lead to pipe ruptures in light-water reactor systems which are needed to mitigate the consequences of accidents or that might increase the consequences of accidents previously analyzed.

(3) Status:

Generic review is under way. On March 10, 1977, an interdivisional Division of Operating Reactors/Division of Systems Safety technical review group was formed to investigate the waterhammer issue and to develop a program for its appropriate consideration in licensing reviews and for operating reactors. Consultant work has been performed by CREARE and Livermore Labs.

(4) References:

1. "Water Hammer in Nuclear Power Plants," NRC Staff Report, June 1, 1977
2. Wallis, G. B., P. H. Rothe, et al., "An Evaluation of PWR Steam Generator Water Hammer" (draft), CREARE Inc., February 1977
3. Sutton, S. B., "An Investigation of Pressure Transient Propagation in Pressurized Water Reactor Feedwater Lines" (preliminary), Lawrence Livermore Laboratory, April 15, 1977
4. Office of Nuclear Reactor Regulation, NRR Technical Activities, Category A, Item 1, "Water Hammer," May 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-1, "Water Hammer" (NUREG-0649)

The references cited in this topic were the precursors of USI A-1. The evaluation required for USI A-1 is identical to SEP Topic V-13; therefore, this SEP topic has been deleted.

TOPIC: VI-1 Organic Materials and Postaccident Chemistry

(1) Definition:

(a) Organic materials
The design basis for selection of paints and other organic materials is not documented for most operating reactors. Therefore, there is a need to review the suitability of paints and other organic materials used inside containment, including the possible interactions of the decomposition products of organic materials with engineered safety features (such as filters).

(b) Postaccident chemistry
Low pH solutions that may be recirculated within containment after a design basis accident (DBA) may accelerate chloride stress corrosion cracking which may lead to equipment failure or loss of containment integrity. Low pH may also increase the volatility of dissolved iodines with a resulting increase in radiological consequences.

(2) Safety Objective:

(a) Organic materials
To assure that organic paints and coatings used inside containment do not behave adversely during accidents when they may be exposed to high radiation fields. In particular, the possibility of coatings clogging sump screens should be minimized.

(b) Postaccident chemistry
To assure that appropriate methods are available to raise or maintain the pH of solutions expected to be recirculated within containment after a DBA.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Sections 6.1.2 and 6.1.3
2. Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants"

TOPIC: VI-2.A Pressure-Suppression-Type BWR Containments

(1) Definition:

BWR pressure-suppression-type containments (for example, Mark I containment) are subjected to hydrodynamic loads during the blowdown phase of a loss-of-coolant accident (LOCA). These loads have the potential for damaging the components and structures (wetwell, internal structures, restraints, supports, and connected systems) of the containment. During a relief valve blowdown into the suppression pool, the wetwell (torus) shell and safety/relief valve restraints may be overstressed. The hydrodynamic loads were not explicitly identified and included in the design of the Mark I pressure-suppression containment.

(2) Safety Objective:

To assure that the structural integrity of pressure-suppression pool containments is maintained under hydrodynamic loading conditions. It has been determined that the upward forces during the blowdown phase following a LOCA potentially cause the Mark I torus to be lifted, causing failure of connecting systems and supports and leading to loss of the containment integrity. Structural modifications and/or changes in the mode of operation might be necessary to assure adequate safety margins.

(3) Status:

Mark I containments are currently evaluated in a two-step generic review program: The Short-Term Program (STP), completed May 1977, has focused on the determination of the magnitude and significance of hydrodynamic loads. In the Long-Term Program (LTP), to be completed by late 1978, the design basis loads will be finalized and the capability of the containment to withstand the loads within the original design structural margins will be verified. This verification will be based in part on research results from NRC and industry sponsored programs. As a result of the STP, the staff required that Mark I plants be operated with a drywell to wetwell differential pressure of at least 1 psi to reduce the vertical loads. In addition, some licensees have modified the torus support system for additional safety margin.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) - Generic Issues (April 1977)
   a. Mark I Containment - STP Technical Specifications
   b. Mark I Containment Evaluation - STP
   c. Mark I Containment Evaluation - LTP
   d. Mark I Safety/Relief Valve Line Restraints in Torus
2. Division of Operating Reactors, DOR Technical Activities, Category A, April 1977
   a. Item 2, "Mark I Containment STP"
   b. Item 3, "Mark I Containment LTP"
   c. Item 23, "Mark II Containment"
3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 12, "Assessment of Column Buckling Criteria," May 1977
4. Division of Systems Safety, DSS Technical Activities, Category A, Item 31, "Determination of LOCA and SRV Pool Dynamic Loads for Water Suppression Containments," April 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-7, "Mark I Containment Long-Term Program" (NUREG-0649)

Under this task, a short-term program that evaluated Mark I containment has provided assurance that the Mark I containment system of each operating BWR facility would maintain its integrity and functional capability during a postulated LOCA. A longer term program for BWR facilities, not yet licensed, is planned wherein the NRC staff will evaluate the loads, load combinations, and associated structural acceptance criteria proposed by the Mark I Owners Group prior to the performance of plant-unique structural evaluations. The Mark I Owners Group has initiated a comprehensive testing and evaluation program to define design basis loads for the Mark I containment system and to establish structural acceptance criteria which will assure margins of safety for the containment system which are equivalent to that which is currently specified in the ASME Boiler and Pressure Vessel Code. Also included in their program is an evaluation of the need for structural modifications and/or load-mitigation devices to assure adequate Mark I containment system structural safety margins.

The long-term program for USI A-7 will assure that all plants with Mark I containments are able to tolerate, without loss of function, the LOCA-induced hydrodynamic loads.

The evaluation required by USI A-7 is identical to SEP Topic VI-2.A; therefore, this SEP topic has been deleted.

TOPIC: VI-2.B Subcompartment Analysis

(1) Definition:

The rupture of a high energy line inside a containment subcompartment can cause a pressure differential across the walls of the subcompartment. In the case of a rupture of a PWR main coolant pipe adjacent to the reactor vessel, the subcooled blowdown produces pressure differentials in the annulus between the reactor vessel and the shield wall and also within the reactor vessel across the core barrel. This asymmetric pressure distribution generates loads on the reactor vessel support and on reactor vessel internals, on other equipment supports, and on subcompartment structures which have not been analyzed previously for most operating reactors.

(2) Safety Objective:

To assure that the reactor vessel supports, reactor vessel internals, and other equipment supports and subcompartment structures are designed with an adequate margin against failure due to these loads. The failure could result in a loss of emergency core cooling system capability.

(3) Status:

The staff is reviewing the nuclear steam supply system vendor and architect-engineer design codes used to calculate the loads produced by the asymmetric pressure distribution. Analyses have been completed for a limited number of operating plants. The W TMD code is approved. Bechtel, Gilbert, and United Engineering have submitted codes for review.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) - Generic Issue, Item 3-5, "Asymmetric LOCA Loads - PWR," April 1977
2. Division of Operating Reactors, DOR Technical Activities, Category A, Item 32, "Asymmetric LOCA Loads (Reactor Vessel Support Problem)," April 1977
3. Division of Systems Safety, DSS Technical Activities, Category A, Item 14, "Asymmetric Blowdown Loads on Reactor Vessel," April 1977
4. Division of Project Management, DPM Technical Activities, Category A, Item 2, "Reactor Vessel Supports (Asymmetric LOCA Loads From Sudden Subcooled Blowdown)," April 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

The references cited in this topic were the precursors of USI A-2. The evaluation required for USI A-2 is identical to SEP Topic VI-2.B (see also SEP Topic III-8.D); therefore, this SEP topic has been deleted.

TOPIC: VI-2.C Ice Condenser Containment

(1) Definition:

Operating experience from the D. C. Cook plant has indicated that sublimation and melting of ice causes a loss of ice inventory and related functional performance problems for the ice consenser system.

(2) Safety Objective:

To assure that a sufficient ice inventory is maintained and to assure the functional performance of the ice condenser system.

(3) Status:

The results of the surveillance program for ice inventory and of the functional performance testing (for example, operation of vent doors) are periodically reviewed by the staff to determine whether the surveillance frequencies should be increased or other action should be taken. Recent surveillance testing indicates that the ice inventory is acceptable and that the D. C. Cook plant can be operated safely for the current fuel cycle. CONTEMPT-4 long-term ice condenser code is expected to be completed by Edgerton, Germeshausen & Grier in October 1977.

(4) Reference:

Division of Operating Reactors, DOR Technical Activities, Category B, Item 53, "Ice Condenser Containments," May 1977

TOPIC: VI-2.D Mass and Energy Release for Postulated Pipe Breaks Inside Containment

(1) Definition:

Review the methods and assumptions of the mass and energy release model, including containment temperatures and pressure response, that were used in previously performed analyses of high-energy line breaks inside containment, including the main steam line break.

(2) Safety Objective:

To assure that design basis conditions (for example, design pressure and temperature) for the containment structure and safety-related equipment are adequate. Determine if the models used in the earlier analyses provide adequate margins of safety when compared with the assumptions and models for current analytical techniques.

(3) Status:

Mass and energy release models, including containment response models, are being reassessed to determine the degree of conservatism in the prediction of the containment pressure and temperature transient resulting from a PWR main steam line break. Application of those models to operating plants is contingent on the results of this reassessment. Mass and energy release models for operating BWR plants are considered in the Mark I Long-Term Program and other BWR review efforts.

(4) References:

1. Division of Operating Reactors, DOR Technical Activities, Category B, May 1977

a. Item 1, "Pipe Break Inside Containment"
b. Item 2, "Mass and Energy Release to Containment"

2. Division of Systems Safety, DSS Technical Activities, Category A, April 1977
   a. Item 7, "Pipe Rupture Design Criteria"
   b. Item 29, "Main Steam Line Break Inside Containment"
3. Division of Systems Safety, DSS Technical Activities Report, Item I-C.B.1, "Mass and Energy Release to Containment," December 1975

TOPIC: VI-3 Containment Pressure and Heat Removal Capability

(1) Definition:

The temperature and pressure conditions inside containment due to a postulated loss-of-coolant accident (LOCA), main steam line or feedwater line break depend on the effectiveness of passive heat sinks and active heat removal systems (for example, containment spray system).

(2) Safety Objective:

To assure that the maximum temperature and pressure following a LOCA, main steam, or feedwater line break have been calculated with conservative assumptions and to assure that the passive heat sinks and active heat removal systems provide the full heat removal capability required to maintain the pressure and temperature below the design pressure and temperature of the containment, of safety-related equipment, and instrumentation inside containment.

(3) Status:

The modified CONTEMPT computer code properly accounts for the condensation of superheated steam on containment passive heat sinks. The effects on the design temperatures within the containment are being studied for plants under licensing review.

(4) References:

1. Standard Review Plan, Section 6.2.1.1.A
2. Division of Systems Safety, DSS Technical Safety Activities Report, December 1975
3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 62, "Effective Operation of Containment Sprays in LOCA," May 1977

TOPIC: VI-4 Containment Isolation System

(1) Definition:

Isolation provisions of fluid system of nuclear power plants limit the release of fission products from the containment for postulated pipe breaks inside containment and thus prevent the uncontrolled release of primary system coolant as a result of postulated pipe breaks outside containment. This must be accomplished without endangering the performance of postaccident safety systems. Review the primary containment isolation provisions, in particular, the containment sump lines and fluid systems penetrating containment. Review the design bases for containment ventilation system isolation valves to determine potential releases from the containment. Review the containment purge mode during normal operation with respect to various accident scenarios and consequences including operation of containment purge valves, closure times, and leak tightness.

(2) Safety Objective:

To assure that the primary containment isolation provisions meet the requirements of 10 CFR 50, Appendix A, General Design Criteria 54 through 57. Some of the operating plants may have too few or too many isolation provisions. Containment purging during normal operation in PWRs has raised a concern regarding the ability of the ventilation system isolation valves to close upon receipt of an accident signal. The use of resilient sealing materials in conjunction with the cycling of these valves has resulted in an increased degradation in the leakage integrity of the valve seats. To assure the adequacy of the maintenance and repair schedule to maintain the leakage integrity of the valves for the service life of the plant. To assure that containment purge operations will not adversely affect the consequences of postulated accidents.

(3) Status:

The functional performance of the sump lines and emergency core cooling systems is being reviewed in conjunction with the Appendix K submittals. Implementation criteria are being developed to apply the requirements of Branch Technical Position CSB 6-4 to containment purging practices and to improve the leakage integrity of ventilation system isolation valves.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 54 through 57
2. Standard Review Plan, Section 6.4.2
3. Standard Review Plan, Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations"

TOPIC: VI-5 Combustible Gas Control

(1) Definition:

Review the combustible gas control system to determine the capability of the system to monitor the combustible gas concentration in the containment, to mix combustible gases within the containment atmosphere, and to maintain combustible gas concentrations below the combustion limits (for example, by recombination, dilution, or purging). For facilities which share recombiners (portable) between units or sites, determine that the recombiners can be made available within a suitable time. For facilities which utilize purging as a primary means of combustible gas control, determine the radiological consequences of the system operation. Reevaluate hydrogen production and accumulation analysis to consider (1) reduction of Zr/water reaction on the basis of five times the Appendix K calculation amount and (2) potential increases in hydrogen production from corrosion of metals inside containment.

(2) Safety Objective:

To prevent the formation of combustible gas explosive concentrations in the containment or in localized regions within containment, following a postulated accident; to assure that the radiological consequences of the system operation are acceptable.

(3) Status:

Proposed 10 CFR 50.44 would permit a BWR licensee to propose an alternate combustible gas control system in lieu of inerting. Four such proposals for containment atmosphere dilution systems are currently under review, and the COGAP II computer code is being revised to perform the system evaluations.

(4) References:

1. Proposed rule 10 CFR Part 50, Section 50.44
2. Division of Operating Reactors, DOR Technical Activities, Category A, Item 8, "Containment Purge During Normal Operation," April 1977
3. Division of Operating Reactors, DOR Technical Activities, Category A, Item 14, "Inerting Requirements/CAD," April 1977
4. Standard Review Plan, Branch Technical Position CSB 6-2, "Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident"
5. Standard Review Plan, Section 6.2.5

(5) Basis for Deletion (Related TMI TASK, USI, or Other SEP Topic):

(a) TMI Action Plan Task II.B.7, "Analysis of Hydrogen Control" (NUREG-0660)

As a result of TMI Task II.B.7, short- and long-term rulemaking to amend 10 CFR 50.44 has been initiated. The short-term rulemaking (interim rule) requires that all Mark I and Mark II containments be inerted. It also requires that the owners of all plants with other containments perform certain analyses of accident scenarios involving hydrogen releases and furnish the staff with a proposed approach for mitigating these hydrogen releases.

The longer-term rulemaking will address both degraded core and melted core issues. In the area of hydrogen control, it will prescribe requirements that are appropriate for operating plants as well as for plants under construction.

(b) USI A-48, "Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment" (NUREG-0705)

Under USI A-48, a Task Action Plan has been defined and is being developed that encompasses the concerns in the Definition and the Safety Objective of SEP Topic VI-5.

The evaluation required by TMI II.B.7 and USI A-48 is identical to SEP Topic VI-5; therefore, this SEP topic has been deleted.

TOPIC: VI-6 Containment Leak Testing

(1) Definition:

Certain requirements of primary reactor containment leakage testing for water-cooled power reactors as described in Appendix J to 10 CFR Part 50 (issued February 1973) have been found to be conflicting, impractical for implementation, or subject to a variety of interpretations. Review the primary reactor containment leak testing program for operating nuclear plants.

(2) Safety Objective:

To assure that the containment leak testing program provides a conservative assessment of the leakage rate through individual leakage barriers and to assure that proper maintenance and repairs are conducted during the service life of the containment. The testing acceptance criteria are established to ensure that containment leakage following a postulated accident will not result in offsite doses exceeding 10 CFR 100 guidelines.

(3) Status:

A generic review for compliance with Appendix J and the review of requested exemptions to the regulation is currently underway. Proposed revisions to Appendix J to improve the testing requirements are under development.

(4) References:

1. 10 CFR Part 50, Appendix J
2. 10 CFR Part 50, Appendix A, GDC 52 and 53
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-10, "Containment Leak Testing - Appendix J," April 1977
4. Division of Operating Reactors, DOR Technical Activities, Category B, Item 33, "Containment Leak Testing Requirements," May 1977
5. Division of Systems Safety, DSS Technical Activities, Category A, Item 30, "Containment Leak Testing," April 1977

TOPIC: VI-7.A.1 Emergency Core Cooling System Reevaluation To Account for Increased Reactor Vessel Upper Head Temperature

(1) Definition:

Loss-of-coolant accident (LOCA) analyses for all Westinghouse reactors were conducted assuming that the water in the upper head region of the reactor vessel was the same as the inlet water temperature because of a bypass flow from the downcomer to the upper head. Temperature measurements made by Westinghouse indicate that the actual temperature of the upper head fluid exceeds cold leg temperature by 50 to 75% of the difference between hot leg and cold leg (inlet) temperature. All operating reactors were required to resubmit LOCA analyses using hot leg temperature for the upper head volume.

(2) Safety Objective:

To provide revised LOCA analyses with correct upper head temperatures to assure that peak clad temperature limits are not exceeded.

(3) Status:

Revised analyses have been received from all Westinghouse plants. All but three have been reviewed and approved.

TOPIC: VI-7.A.2 Upper Plenum Injection

(1) Definition:

Emergency core cooling system (ECCS) evaluation of Westinghouse two-loop plants was performed assuming that low pressure pumped injection is delivered directly to the lower plenum. However, ECC coolant is delivered directly into the upper plenum. Interaction of the cold injection water with the steam exiting from the core during refill and reflood and the heat transfer effects during the downward passage to the lower plenum have not been adequately considered.

(2) Safety Objective:

To provide assurance that existing analyses with Westinghouse two-loop plants are acceptable either by showing that the present analyses are conservative, or by developing a new ECCS model which considers upper plenum injection.

(3) Status:

The staff met with the licensees and Westinghouse on January 11 and 26, 1977. The staff requested that the licensees formally submit the information presented at the January 26, 1977 meeting. Two Westinghouse reports have been received to date. The staff is continuing to evaluate the problem. Research requested by the Office of Nuclear Reactor Regulation and performed by the Office of Nuclear Regulatory Research in the semiscale facility provided basis for evaluation.

TOPIC: VI-7.A.3 Emergency Core Cooling System Actuation System

(1) Definition:

Review the emergency core cooling system (ECCS) actuation system with respect to the testability of operability and performance of individual active components of the system and of the entire system as a whole under conditions as close to the design condition as practical.

(2) Safety Objective:

To assure that all ECCS components (for example, valves and pumps) are included in the component and system test. To assure that the frequency and scope of the periodic testing are adequate and meet the requirements of General Design Criterion 37.

(3) Status:

New applications (construction permit and operating license) are reviewed in accordance with the Standard Review Plan and the references listed below. No specific activity for operating reactors is in progress.

(4) References:

1. Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Function"
2. Standard Review Plan, Branch Technical Position EICSB-25, "Guidance for the Interpretation of General Design Criterion 37 for Testing the Operability of the Emergency Core Cooling System as a Whole"
3. 10 CFR Part 50, Appendix A, GDC 37

TOPIC: VI-7.A.4 Core Spray Nozzle Effectiveness

(1) Definition:

Core spray systems are designed with a nozzle or a set of nozzles arranged above the core in such a way that, following a LOCA, a spray of water will be distributed over the top of the core so that each fuel bundle will receive a specified minimum flow which will provide adequate core cooling. Recent test data for a single nozzle in a steam environment noted partial or complete collapse of the spray cone and/or a shift in the direction of spray. These effects were not included in earlier full scale spray tests in air.

(2) Safety Objective:

To assure adequate spray cooling following a LOCA.

(3) Status:

The NRC has reviewed and accepted spray system performance for multiple nozzle spray systems, but has not accepted spray systems with a single overhead spray nozzle. Recent tests in Florida on the Big Rock Point spray nozzle indicate incomplete core coverage. As a result of these tests, NRC is requesting further testing by GE of multiple spray nozzles.

(4) References:

1. Letter from K. Goller, NRC, to operating reactor branch chiefs, Subject: "Generic Issue - Effects of Steam Environment on Core Spray Distribution for Non-jet Pump BWRs," December 7, 1976
2. General Electric, GE Topical Report NEDO-10846, "BWR Core Spray Distribution"

TOPIC: VI-7.B Engineered Safety Feature Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)

(1) Definition:

Most PWRs require operator action to realign emergency core cooling (ECC) systems for the recirculation mode following a LOCA.

We have been requiring, on an ad hoc basis, some automatic features to realign the ECCS from the injection to the recirculation mode of operation.

(2) Safety Objective:

To increase the reliability of long-term core cooling by not requiring operator action to change system realignment to the recirculation mode.

(3) Status:

A draft Branch Technical Position has been prepared which covers both ECC and containment spray systems. The proposed position is awaiting review by the Regulatory Requirements Review Committee.

(4) Reference:

American National Standards Institute, Draft ANSI Standard N 660, "Proposed American National Standard Criteria for Safety-Related Operator Actions"

TOPIC: VI-7.C Emergency Core Cooling System (ECCS) Single-Failure Criterion and Requirements for Locking Out Power to Valves, Including Independence of Interlocks on ECCS Valves

(1) Definition:

The physical locking out of electrical sources to specific motor-operated valves required for the engineered safety functions of ECCS has been required, based on the assumption that a spurious electrical signal at an inopportune time could activate the valves to the adverse position; for example, closed rather than open, or opened rather than closed. There is some concern that interlock circuitry on ECCS valves may not be independent such that a single failure of an interlock due to equipment malfunction or operator error could defeat more than one interlock and cause the valves to be cycled to the wrong position.

(2) Safety Objective:

To ensure that all power-operated valves which could affect emergency core cooling (ECC) system performance by being in the wrong position have power removed except when in use. This will ensure that ECC systems are not defeated by having a valve in the wrong position.

(3) Status:

The staff plans to reconsider EICSB BTP-18 and RSB BTP-6-1.

TOPIC: VI-7.C.1 Appendix K--Electrical Instrumentation and Control Re-reviews

(1) Definition:

During the Appendix K reviews of some facilities initially considered, a detailed electrical instrumentation and control review was not performed. Re-review the modified ECCS of these facilities to confirm that it is designed to meet the most limiting single failure.

(2) Safety Objective:

To assure that the modified ECCS is designed to meet the most limiting (design basis) single failure.

(3) Status:

No current activity in the Division of Operating Reactors.

(4) References:

1. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems"
2. Institute of Electrical and Electronics Engineers, IEEE Std. 308, "Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations"

TOPIC: VI-7.C.2 Failure Mode Analysis (Emergency Core Cooling System)

(1) Definition:

Failure modes and effects criticality analyses (FMECA) would be conducted for the purpose of systematically determining potential single failures in emergency core cooling (ECC) systems.

(2) Safety Objective:

To determine if single failures exist in ECC system as an aid in assessing overall plant safety.

(3) Status:

FMECAs have been conducted on the hydraulic portion of ECC systems of representative plant types. In addition, single-failure analyses were performed on each plant as a part of the required Appendix K analysis except for those plants with stainless steel clad cores.

TOPIC: VI-7.C.3 Effect of PWR Loop Isolation Valve Closure During a Loss-of-Coolant Accident on Emergency Core Cooling System Performance

(1) Definition:

Some PWRs are equipped with loop isolation valves. The effect of spurious closure of a loop isolation valve during a LOCA has never been analyzed. To ensure emergency core cooling system (ECCS) performance, power in some cases has been removed from loop isolation valves to prohibit spurious closure.

(2) Safety Objective:

To assure that all plants with loop isolation valves have power removed during operation, or that other acceptable measures are taken to preclude inadvertent closing.

(3) Status:

In most cases power has been removed from loop isolation valves, and this is confirmed as part of staff ECCS performance evaluations. This has not been confirmed for all plants with loop isolation valves.

TOPIC: VI-7.D Long-Term Cooling Passive Failures (for example, Flooding of Redundant Components)

(1) Definition:

The General Design Criteria require that the emergency core cooling systems (ECCSs) shall be capable of providing adequate core cooling following a loss-of-coolant accident, assuming a single failure in emergency core cooling systems. The staff assumes the single failure to be either an active failure during the injection phase, or an active or passive failure during the long-term recirculation phase. The physical layouts of engineered safety feature pumps and components on some pressurized water reactors make them vulnerable to flooding that might result from passive failures in system piping. Protection for pipe cracks or ruptures is not required because of the low probability of occurrence during the ECCS recirculation mode.

(2) Safety Objective:

To provide for increased reliability of ECCSs by assuring that passive failures will not cause flooding and failure of ECCS valves and equipment.

(3) Status:

Issue identified by Fluegge in letter to Rowden, October 24, 1976. Staff response was prepared which concluded that "...consideration of this issue does not warrant revisions to any existing licenses or changes in present priority for addressing the treatment of passive failures subsequent to a LOCA. ECCS passive failure criteria being implemented by the staff require considerations of additional leakage but not pipe breaks beyond the initiating LOCA."

(4) Reference:

NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 7, "Passive Failures Following a Loss-of-Coolant Accident," December 1976

TOPIC: VI-7.E Emergency Core Cooling System Sump Design and Test for Recirculation Mode Effectiveness

(1) Definition:

Following a loss-of-coolant accident in a PWR, an emergency core cooling system (ECCS) automatically injects water into the system to maintain core cooling. Initially, water is drawn from a large supply tank. Water discharging from the break and containment spray collects in the containment building sump. When the supply tank has emptied to a predetermined level, the ECCS is switched from the "injection" mode to the "recirculation" mode. Water is then drawn from the containment building sump.

ECCSs are required to operate indefinitely in this mode to provide decay heat removal. Certain flow conditions could occur in the sump, which could cause pump failures. These include entrained air, prerotation or vortexing, and losses leading to deficient net positive suction head.

(2) Safety Objective:

To confirm effective operation of ECCSs in the recirculation mode.

(3) Status:

Confirmation through preoperational testing is now required on all construction permits. Staff has been accepting scaled tests in lieu of preoperational tests at the operating-license stage. Some plants have required modification to achieve vortex control.

(4) Reference:

Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," (paragraph b(2))

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-43, "Containment Emergency Sump Reliability" (NUREG-0510 and NUREG-0660)

The definition of this topic and the references cited are covered by USI A-43. The evaluation for USI A-43 is identical to SEP Topic VI-7E; therefore, this SEP topic has been deleted.

TOPIC: VI-7.F Accumulator Isolation Valves Power and Control System Design

(1) Definition:

For many loss-of-coolant accidents, the performance of the ECCS in PWR plants depends upon the proper functioning of the accumulators. The motor-operated isolation valve, provided between the accumulator and the primary system, must be considered to be "operating bypass" (IEEE 279-1971) because, when closed, it prevents the accumulator from performing the intended protective function. The motor-operated isolation valve should be designed against a single failure that can result in a loss of capability to perform a safety function.

(2) Safety Objective:

To assure that the accumulator isolation valve meets the "operation bypass" requirements of IEEE 279-1971, which states that the bypass of a protective function will be removed automatically whenever permissive conditions are not met. To assure that a single failure in the electrical system or single operator error cannot result in the loss of capability of an accumulator to perform its safety function.

(3) Status:

Staff positions listed below are implemented on new applications. No systematic review program for operating reactors exists.

(4) References:

1. Institute of Electrical and Electronics Engineers, IEEE Std. 279-1971, "Criteria for Protection System for Nuclear Power Generating Stations"
2. Standard Review Plan, Branch Technical Position EICSB-4, "Requirements on Motor-Operated Valves in the ECCS Accumulator Lines"
3. Standard Review Plan, Branch Technical Position EICSB-18, "Application of Single Failure Criteria to Manually-Controlled Electrically Operated Valves"

TOPIC: VI-8 Control Room Habitability

(1) Definition:

Control rooms in operating plants may not fully comply with General Design Criterion 19. This review should include, but not be limited to, analysis of the control room air infiltration rate, ventilation system isolability and filter efficiency, shielding, emergency breathing apparatus, short distance atmospheric dispersion, operator radiation exposure, and onsite toxic gas storage proximity.

(2) Safety Objective:

To assure that the plant operators can safely remain in the control room to manipulate the plant controls after an accident.

(3) Status:

The Division of Operating Reactors now reviews control room habitability in operating plants when related licensing actions (for example, assessment of BWR containment air dilution system post-LOCA radiological impact) require it. The Division of Site Safety and Environmental Analysis has a technical assistance contract with the National Bureau of Standards to measure the control room air infiltration rate at a few operating plants. These measurements will be used to gauge the conservatism of the assumed air infiltration rates currently used by NRC. Some reviews are now in progress for plants we have reason to believe do not meet General Design Criterion 19 (San Onofre Nuclear Generating Station Unit 1, Vermont Yankee, St. Lucie).

(4) References:

1. Standard Review Plan, Section 6.4
2. 10 CFR Part 50, Appendix A, GDC 19
3. Murphy, K. G., and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19," in Proceedings of the Thirteenth AEC Air Cleaning Conference, August 1974
4. Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release"
5. Regulatory Guide 1.95, Rev. 1, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release"

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

TMI Action Plan Task III.D.3.4, "Control Room Habitability Requirements" (NUREG-0737)

The review criteria required by Task III.D.3.4 (NUREG-0737, pp. 3-197) are identical to the review criteria specified in the Definition and References of SEP Topic VI-8; therefore, this SEP topic has been deleted.

TOPIC: VI-9 Main Steam Line Isolation Seal System (BWR)

(1) Definition:

Operating experience has indicated that there is a relatively high failure rate and variety of failure modes for components of the main steam isolation valve leakage control system in certain operating BWRs.

(2) Safety Objective:

To assure that leakage rate limits are not exceeded and the resulting calculated offsite doses do not exceed 10 CFR Part 100 guidelines using the staff's assumptions.

(3) Status:

Experience from surveillance testing as reported in recent licensee event reports is compiled by the Division of Operating Reactors to serve as a basis for identifying design improvements and for preparing recommendations for future revisions to Regulatory Guide 1.96.

(4) References:

1. Division of Operating Reactors, DOR Technical Activities, Category B, "Main Steam Line Leakage Control System," May 1977
2. Regulatory Guide 1.96, "Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants"
3. Standard Review Plan, Section 6.7

TOPIC: VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing

(1) Definition:

Review the reactor trip system (RTS) and engineered safety features (ESF) test program to verify RTS and ESF operability on a periodic basis and to verify RTS and ESF response time.

(2) Safety Objective:

To assure the operability of the RTS and ESF, on a periodic basis, including verification of sensor response times. To ensure that the RTS and ESF test program demonstrates a high degree of availability of the systems and the response times assumed in the accident analyses are within the design specifications.

(3) Status:

The test program of the RTS and ESF of new license applications is reviewed in accordance with the Standard Review Plan, including applicable Branch Technical Positions. Some licensees have agreed to perform response-time measurements. Operability testing is probably performed, in one form or another, for most licensees of operating reactors.

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB-24, "Testing of Reactor Trip System and Engineered Safety Feature Actuation System Sensor Response Times"
2. Memorandum from V. Stello, NRC, to V. A. Moore, Subject: "GESSAR Second Round of Questions No. 2 and No. 9," October 12, 1973
3. Regulatory Guides
   1.22, "Periodic Testing of Protection System Actuation Functions"
   1.105, "Instrument Setpoints"
   1.118, "Periodic Testing of Electric Power and Protection Systems"

TOPIC: VI-10.B Shared Engineered Safety Features, Onsite Emergency Power, and Service Systems for Multiple Unit Stations

(1) Definition:

The sharing of engineered safety features (ESF) systems, including onsite emergency power systems, and service systems for a multiple-unit facility can result in a reduction of the number and of the capacity of onsite systems to below that which normally is provided for the same number of units located at separate sites. Review these shared systems for multiple-unit stations.

(2) Safety Objective:

To assure that: (1) the interconnection of ESF, onsite emergency power, and service systems between different units is not such that a failure, maintenance, or testing operation in one unit will affect the accomplishment of the protection function of the systems(s) in other units; (2) the required coordination between unit operators can cope with an incident in one unit and safe shutdown of the remaining units(s); and (3) system overload conditions will not arise as a consequence of an accident in one unit coincident with a spurious accident signal or any other single failure in another unit.

(3) Status:

A systematic review of shared ESF, onsite emergency power, and service systems for operating multiple-unit stations is not being conducted. The EICSB Branch Technical Position is applied in the review of new licensee applications.

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB-7, "Shared Onsite Emergency Electric Power Systems for Multi-Unit Stations"
2. Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants"

TOPIC: VII-1.A Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices

(1) Definition:

Nonsafety systems generally receive control signals from the reactor protection system (RPS) sensor current loops. The nonsafety sensor circuits are required to have isolation devices to ensure the independence of the RPS channels. Requirements for the design and qualification of isolation devices are quite specific. Recent operating experience has shown that some of the earlier isolation devices or arrangements at operating plants may not be effective.

(2) Safety Objective:

To verify that operating reactors have RPS designs which provide effective and qualified isolation of nonsafety systems from safety systems to assure that safety systems will function as required.

(3) Status:

A limited generic review of isolation devices is being performed by the Division of Operating Reactors as part of a followup on LER No. 76-42/IT for Calvert Cliffs Unit 1 (TAC 6696). This limited generic review should be complete by August 1, 1977.

(4) References:

1. Licensee Event Report No. 76-42/IT, Calvert Cliffs Unit 1 (Technical Assignment Control (TAC) No. 6696)
2. Standard Review Plan, Section 7.2

TOPIC: VII-1.B Trip Uncertainty and Setpoint Analysis Review of Operating Data Base

(1) Definition:

As a result of Issue No. 13 in NUREG-0138 (Ref. 1) the staff is conducting a survey of plants at the operating-license stage of review to more specifically identify the margin between actual allowable trip parameter limits (from safety analyses standpoint) and actual reactor protection system (RPS) setpoints specified in the Technical Specifications. To clearly identify the setpoint margins, both the ultimate allowable and the specified nominal setting will be identified in the Technical Specifications.

(2) Safety Objective:

To assure that the margins between the allowable trip parameters and the actual RPS setpoints are adequate and properly identified.

(3) Status:

Implementation letters have been sent to the current applicants for operating licenses. The Technical Specifications for operating reactors are only being changed to include both values if a particular plant is converting to Standard Technical Specifications.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 13, "Instrument Trip Setpoints in Standard Technical Specifications," November 1976
2. Memorandum from V. Stello, NRC, to R. Boyd, Subject: "Instrument Trip Setpoint Values," February 18, 1977

3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 29, "Instrument Trip Setpoints on Standard Technical Specifications," May 1977

TOPIC: VII-2 Engineered Safety Features System Control Logic and Design

(1) Definition:

During the staff review of the safety injection system (SIS) reset issue (Ref. 1) the staff determined that the engineered safety features actuation systems (ESFASs) at both PWRs and BWRs may have design features that raise questions about the independence of redundant channels, the interaction of reset features and individual equipment controls, and the interaction of the ESFAS logic that controls transfers between onsite and offsite power sources. Review the as-built logic diagrams and schematics, operator action required to supplement the ESFAS automatic actions, the startup and surveillance testing procedures for demonstrating ESFAS performance.

Several specific concerns exist with regard to the manual SIS reset feature following a LOCA: (1) If a loss of offsite power occurs after reset, operator action would be required to remove normal shutdown cooling loads from the emergency bus and reestablish emergency cooling loads. Time would be critical if the loss of offsite power occurred within a few minutes following a LOCA. (2) If loss of offsite power occurs after reset, some plants may not restart some essential loads such as diesel cooling water. (3) The plant may suffer a loss of ECCS delivery for some time period before emergency power picks up the ECCS system.

Review the ESF system control logic and design, including bypasses, reset features, and interactions with transfers between onsite and offsite power sources.

(2) Safety Objective:

To assure that the ESFASs are designed and installed so that the necessary automatic control of engineered safety features equipment can be accomplished when required.

(3) Status:

A review of ESFASs of operating PWRs is being performed by the Division of Operating Reactors as part of the followup action to Reference 1 (to be completed end of 1977).

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 4, "Loss of Offsite Power Subsequent to Manual Safety Injection Reset Following a LOCA," November 1976
2. Division of Operating Reactors, DOR Technical Activities Category A, Item 22, "Loss of Offsite Power Subsequent to Manual Reset," April 1972

3. Regulatory Guide 1.41, "Preoperational Testing of Redundant Onsite Electric Power Systems To Verify Proper Load Group Assignments"

TOPIC: VII-3 Systems Required for Safe Shutdown

(1) Definition:

Review plant systems that are needed to achieve and maintain a safe shutdown condition of the plant, including the capability for prompt hot shutdown of the reactor from outside the control room. Included also, a review of the design capability and method of bringing a PWR from a high-pressure condition to low-pressure cooling assuming the use of only safety-grade equipment.

(2) Safety Objective:

(1) To assure the design adequacy of the safe shutdown system to (i) initiate automatically the operation of appropriate systems, including the reactivity control systems, such that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences or postulated accidents and (ii) initiate the operation of systems and components required to bring the plant to a safe shutdown.

(2) To assure that the required systems and equipment, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown are located at appropriate locations outside the control room and have a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

(3) To assure that only safety-grade equipment is required for a PWR plant to bring the reactor coolant system from a high-pressure condition to a low-pressure cooling condition.

(3) Status:

A survey of remote shutdown capability of operating plants was performed some time ago by the Division of Operating Reactors. A technical activity has been proposed by the Division of Project Management (see reference below) regarding safety objective (3). No other activities are in progress.

(4) Reference:

Division of Project Management, DPM Technical Activities, Category A, Item 7, "Isolating Low Pressure Systems Connected to the RCPB," April 1977

TOPIC: VII-4 Effects of Failure in Nonsafety-Related Systems on Selected Engineered Safety Features

(1) Definition:

Potential combinations of transients and accidents with failures of nonsafety-related control systems were not specifically evaluated in the original safety analysis of currently operating reactor plants. Review the effects of control system malfunctions as initiating events for anticipated transients and also as failures concurrent with or subsequent to anticipated events or postulated accidents initiated by a different malfunction (for example, the effect of the loss of the plant air system on the plant control and monitoring system). A complete discussion is provided in Reference 1.

(2) Safety Objective:

To assure that any credible combination of a nonsafety-related system failure with a postulated transient or accident will not cause unacceptable consequences.

(3) Status:

A technical assistance contract with Oak Ridge National Laboratory for failure mode analyses of control systems was initiated to determine sensitive areas of the plant designs. The results of this program in conjunction with the results of the failure mode and effects analyses for transients and accidents being performed under contract by Idaho Nuclear Engineering Laboratory should provide a basis for any new review and safety requirements.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR Staff," Issue 22, "Systematic Review of Normal Plant Operation and Control System Failures," December 1976
2. Memorandum from V. Stello, NRC, to R. J. Hart, December 23, 1976, NRR letter No. 46.
3. Division of Operating Reactors, DOR Task Force Report on SEP, Appendix B (TFL 118), November 1976
   a. Item 33, "Safety Related Control Power"
   b. Item 34, "Safety Related Instrumentation Power"
   c. Item 56, "Effect of Failure in Non-Safety Related Systems During Design Basis Events"
   d. Item 57, "Loss of Plant Air System (Effect on Plant Control and Monitoring)"
   e. Item 77, "Safety Related Control and Instrument Power"
4. Directorate of Operational Technology, DOT Recommended List of SEP Subjects, C DOT 102, Item 100z, "Loss of Plant Air System (Effect on Plant Control and Monitoring)," Spring 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-47, "Safety Implications of Control System" (NUREG-0705 and NUREG-0606)

The issue defined in Reference 1 (NUREG-0153, Item 22) is as follows:

> In evaluating plant safety, the effects of control system malfunctions should be reviewed as initiating events for

anticipated transients and also as failures that could occur concurrently subsequent to postulated anticipated events (initiated by a different malfunction) or postulated accidents.

The issue defined in USI A-47 is, in part, as follows:

> This issue concerns the potential for transients or accidents being made more severe as a result of the failure or malfunction of control systems. These failures or malfunctions may occur independently, or as a result of the accident or transient under consideration.

(b) USI A-17, "Systems Interactions in Nuclear Power Plants" (NUREG-0649 and NUREG-0606)

The purpose of this task is to develop a method for conducting a disciplined and systematic review of nuclear power plant systems, for both process function couplings of systems and space couplings, to identify the potential sources and types of systems interactions that are determined to be potentially adverse.

A report has been developed, "Final Report - Phase 1 Systems Interaction Methodology Applications Program," NUREG/CR-1321, SAND 80-0384, whose objectives are:

1. To develop a methodology for conducting a disciplined and systematic review of nuclear power plant systems which facilitates identification and evaluation of systems interactions that affect the likelihood of core damage.

2. To use the methodology to assess the Standard Review Plan to determine the completeness of the plan in identifying and evaluating a limited range of systems interactions.

The work done under USI A-17 may be useful in the development of USI A-47.

The Definition of USI A-47 is identical to that of Topic VII-4; therefore, this SEP topic has been deleted.

TOPIC: VII-5 Instruments for Monitoring Radiation and Process Variables During Accidents

(1) Definition:

The adequacy of the instruments for monitoring radiation and process variables during accidents has not been reviewed for conformance with Regulatory Guide 1.97. A generic review is planned to assess the licensee's existing or proposed monitoring instruments during and following accidents to determine the adequacy of their range, response, and qualifications, and to determine the sufficiency of the variables to be monitored. Certain instruments to monitor conditions beyond the design basis accidents will also be required in accordance with an Regulatory Requirements Review Committee (RRRC) determination (Reference 3).

(2) Safety Objective:

To assure that plant operators and emergency response personnel have available sufficient information on plant conditions and radiological releases to determine appropriate in-plant and offsite actions throughout the course of any accident. The instrumentation should also provide recorded transient or trend information necessary for postaccident evaluation of the event. The ability to follow the course of accidents beyond the design basis accidents is also required.

(3) Status:

Generic review of instrumentation to follow the course of accidents in operating plants and in all plants now under construction or seeking a construction permit will begin with the issuance of Regulatory Guide 1.97, Revision 1, this year. Submittals describing the facilities' postaccident instrumentation will be obtained from all operating licensees and reviewed by the end of 1978. The implementation of Regulatory Guide 1.97, Revision 1 on operating plants is proceeding independent of the SEP. The Regulatory Requirements Review Committee has determined that Revision 1 to Regulatory Guide 1.97 should be treated as a Category 2 item (backfit on operating plants on a case-by-case basis).

(4) References:

1. Memorandum from H. G. Mangelsdorf (ACRS) to L. M. Muntzing (Regulations), August 14, 1973
2. Memorandum from L. M. Muntzing (Regulation) to H. G. Mangelsdorf (ACRS), November 1, 1973
3. Memorandum from R. B. Minogue (SD) to E. G. Case (NRR), Enclosure, Proposed Revision 1 to Regulatory Guide 1.97, April 4, 1977
4. Standard Review Plan, Section 7.5
5. Standard Review Plan, Section 7.6
6. Standard Review Plan, Section 11.5
7. Memorandum from T. A. Ippolito (EICSB) to Emergency Instrumentation Task Force Members, August 12, 1974
8. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR Staff," Issue 21, "Instruments for Monitoring Both Radiation and Process Variable During Accidents," December 1976
9. Minutes of Regulatory Requirements Review Committee meeting, January 28, 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

TMI Action Plan Task II.F, "Instrumentation and Controls"
NUREG-0660 and NUREG-0737

There are three subtasks under Task II.F as follows:

(a) II.F.1 - Additional Accident Monitoring Instrumentation

(b) II.F.2 - Identification of and Recovery From Conditions Leading to Inadequate Core Cooling

(c) II.F.3 - Instruments for Monitoring Accident Conditions

Specific positions on the required instrumentation for II.F.1 and II.F.2 are in NUREG-0737 and Regulatory Guide 1.97, Revision 2 (December 1980). Instrumentation need for II.F.3 is also in Regulatory Guide 1.97, Revision 2.

The emphasis of TMI Task II.F is the monitoring of radiation and process variables; guidance for this relies primarily on Regulatory Guide 1.97. This is identical to the review proposed in Topic VII-5; therefore this SEP topic has been deleted.

TOPIC: VII-6 Frequency Decay

(1) Definition:

In an issue of Reference 1 it is stated that the staff should require that a postulated rapid decay of the frequency of the offsite power system be included in the accident analysis and that the result be demonstrated to be acceptable. Alternatively, the reactor coolant pump (RCP) circuit breakers should be designed to protection system criteria and tripped to separate the pump motors from the offsite power system. Rapid decay of the frequency of the offsite power system has the potential for slowing down or breaking the RCP, thereby reducing the coolant flow rates to levels not considered in previous analyses.

(2) Safety Objective:

To assure that the reactor coolant flow rate will not decrease below those assumed for a flywheel coastdown.

(3) Status:

Oak Ridge National Laboratory, under a technical assistance program, is currently reviewing the frequency decay rate and its effects on RCPs. This program should be completed before the end of this year and this issue resolved.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 9, "Frequency Decay," November 1976
2. Division of Operating Reactors, DOR Technical Activities, Category B, Item 27, "Frequency Decay," May 1977

TOPIC: VII-7 Acceptability of Swing Bus Design on BWR-4 Plants

(1) Definition:

The swing bus in the original BWR-4 design was used to provide power from either of two redundant electric sources to the low-pressure coolant injection (LPCI) valves by means of an automatic transfer scheme. A single failure in the transfer circuitry could result in paralleling the two redundant electric power sources, thereby degrading their functional capabilities. Review licensee's swing bus automatic transfer circuitry to verify that it is immune to single failures which could lead to paralleling the two electric power sources.

(2) Safety Objective:

To assure that the swing bus design will not propagate an electrical failure between two redundant power sources due to a single failure in the automatic transfer circuit at the BWR-4 swing bus.

(3) Status:

During the course of generic review for compliance with emergency core cooling system criteria 10 CFR 50.46 and Appendix K, some licensees have elected to modify the LPCI system to take credit for a portion of the LPCI flow. These facilities have replaced the swing bus design with a split bus configuration which complies with the requirements of Regulatory Guide 1.6. Not all facilities required a modification of the LPCI to meet the criteria and have retained the swing bus design.

The issue of the swing bus design was identified in Reference 1 and in addition in a letter from the Advisory Committee on Reactor Safeguards (ACRS) dated December 12, 1976.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 3, "Acceptability of Swing Bus Design of BWR-4 Plants," November 1976
2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems"
3. 10 CFR Part 50, Appendix A, GDC 17
4. Institute of Electrical and Electronics Engineers, IEEE Std. 308, "Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations"

TOPIC: VIII-1.A Potential Equipment Failures Associated With Degraded Grid Voltage

(1) Definition:

A sustained degradation of the offsite power source voltage could result in the loss of capability of redundant safety loads, their control circuitry, and the associated electrical components required to perform safety functions.

(2) Safety Objective:

To assure that a degradation of the offsite power system will not result in the loss of capability of redundant safety-related equipment and to determine the susceptibility of such equipment to the interaction of onsite and offsite emergency power sources.

(3) Status:

A program plan has been developed which includes a short-term program for the review of the emergency power systems of operating reactors and a long-term program to identify those conditions affecting the offsite power sources which may require that additional safety measures be taken.

(4) References:

1. NUREG-0090-5, "Report to Congress, Abnormal Occurrences at Millstone 2, July-September 1976," March 1977
2. Memorandum from D. G. Eisenhut, NRC, to K. R. Goller, Subject: "Staff Positions (Short-Term Program)," April 20, 1977
3. Letters to licensees, August 12 and 13, 1976
4. Division of Operating Reactors, DOR Technical Activities, Category A, Item 9, "Potential Equipment Failures Associated with a Degraded Off-site Power Source," April 1977

TOPIC: VIII-2 Onsite Emergency Power Systems (Diesel Generator)

(1) Definition:

Diesel generators, which provide emergency standby power for safe reactor shutdown in the event of total loss of offsite power, have experienced a significant number of failures. The failures to date have been attributed to a variety of causes, including failure of the air startup, fuel oil, and combustion air systems. In some instances, the malfunctions were due to lockout. The information available to the control room operator to indicate the operational status of the diesel generator was imprecise and could lead to misinterpretation. This was caused by the sharing of a single annunciator station by alarms that indicate conditions that render a diesel generator unable to respond to an automatic emergency start signal and alarms that only indicate a warning of abnormal, but not disabling, conditions. Another cause was the wording on an annunciator window which did not specifically say that the diesel generator was inoperable (that is, unable at the time to respond to an automatic emergency start signal), when in fact it was inoperable for that purpose. The review includes the qualification, reliability, operation at low loads, lockout, fuel oil, and testing of diesel generators.

(2) Safety Objective:

To assure that the diesel generator meets the availability requirements for providing emergency standby power to the engineered safety features.

(3) Status:

Under a technical assistance request (in preparation), a thorougn evaluation of all reported failures, including a comprehensive evaluation of diesel manufacturer and utility procedures for inspection, maintenance, and operation, will be performed. Letters were sent on March 29, 1977 to all the affected licensees requesting additional information about diesel generator status indication in the control room. Our intention is to require that at least one annunciation be provided in the control room which will alarm whenever the diesel generator is unavailable due to any lockout condition.

(4) References:

1. Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants"
2. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-11, "Diesel Generator Lockout," April 1977

TOPIC: VIII-3.A Station Battery Capacity Test Requirements

(1) Definition:

Review the Technical Specification, including the test program, with regard to the requirement for periodic surveillance testing of onsite Class IE batteries and the extent to which the test meets Section 5.3.6 of IEEE Std. 308-1971, to determine battery capacity.

(2) Safety Objective:

To assure that the onsite Class IE battery capacity is adequate to supply dc power to all safety-related loads required by the accident analyses and is verified on a periodic basis. This effort is needed to ensure that the test to determine battery capacity includes (1) an acceptance test of battery capacity performed in accordance with Section 4.1 of IEEE Std. 450-1975; (2) a performance discharge test listed in Table 2 of IEEE Std. 308-1971, performed according to Sections 4.2 and 5.4 of IEEE Std. 450-1975; and (3) a battery service test described in Section 5.6 of IEEE Std. 450-1972, to be performed during each refueling operation.

(3) Status:

The review of station battery capacity test requirements is applicable to all operating reactors. There is no ongoing effort on this subject for operating reactors except for those reactors converting to Standard Technical Specifications.

(4) References:

1. Standard Review Plan, Appendix 7-A, Branch Technical Position EICSB 6
2. Institute of Electrical and Electronics Engineers, IEEE Std. 308-1971, 1974, "Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations"

3. Institute of Electrical and Electronics Engineers, IEEE Std. 450-1975, "Recommanded Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations"
4. Memorandum from J. G. Keppler to R. H. Vollmer, NRC, March 20, 1972
5. Memorandum from V. D. Thomas to R. Carlson, January 18, 1972

TOPIC: VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

(1) Definition:

Review the dc power system battery, battery charger, and bus voltage monitoring and annunciation design with respect to dc power system operability status indication to the operator. This information is needed so that timely corrective measures can be taken in the event of loss of an emergency dc bus.

(2) Safety Objective:

To assure the design adequacy of the dc power system battery and bus voltage monitoring and annunciation schemes such that the operator can (1) prevent the loss of an emergency dc bus or (2) take timely corrective action in the event of loss of an emergency dc bus.

(3) Status:

The review of the dc power system battery and bus voltage monitoring and annunciation adequacy as it relates to the loss of an emergency dc bus is applicable to all operating reactors. This topic is included in the NRR Technical Activity, "Adequacy of Safety Related DC Power Supplies."

(4) Reference:

Standard Review Plan, Section 8.3.2

TOPIC: VIII-4 Electrical Penetrations of Reactor Containment

(1) Definition:

Review the electrical penetration assembly with respect to the capability to maintain containment integrity during short-circuit current conditions and mechanical integrity during the worst expected fault current vs. time conditions resulting from single random failures of circuit overload protection devices.

(2) Safety Objective:

To assure that all electrical penetrations in the containment structure, whether associated with Class IE circuits or non-Class IE circuits, are designed not to fail from electrical faults during a loss-of-coolant accident.

(3) Status:

The subject of electrical cable penetrations was identified in Reference 1 and has been proposed as a Technical Activity Category A item by the Division of Systems Safety (Reference 2). The purpose of that activity is a reevaluation of the penetrations to clarify and augment the design safety margin.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue 18, "Electrical Cable Penetration of Reactor Containment," December 1976
2. Division of Systems Safety, DSS Technical Activity, Category A, Item 36, "Electrical Cable Penetrations of Reactor Containment," April 1977
3. Regulatory Guide 1.63, "Electric Pentration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants"
4. Institute of Electrical and Electronics Engineers, IEEE Std. 317-1976, "Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations"

TOPIC: IX-1 Fuel Storage

(1) Definition

Review the storage facility for new and irradiated fuel, including the cooling capability and seismic classification of the fuel pool cooling system of the spent fuel storage pool. Specifically review the expansion of the onsite spent fuel storage capacity, including the structural response of the fuel storage pool and the racks, the criticality analysis for the increased number of stored fuel assemblies at reduced spacing, and the capability of the spent fuel cooling system to remove the additional heat load.

(2) Safety Objective:

To assure that new and irradiated fuel is stored safely with respect to criticality ($k_{eff} < 0.95$), cooling capability (outlet temperature < 150°F), shielding, and structural capability.

(3) Status:

Approximately two-thirds of the operating reactor plants have requested authorization to increase the storage capacity of their fuel storage pool. The applications are reviewed on a case-by-case basis. New or modified storage rack designs are reviewed against current design criteria; however, the existing pool structure is based on original design criteria.

(4) References

1. Division of Operating Reactors, DOR Technical Activities, Category A, Item 27, "Increase in Spent Fuel Storage Capacity," April 1977
2. American National Standards Institute, ANSI-210, "Design Objectives for Spent Fuel Storage Facilities"

TOPIC: IX-2 Overhead Handling Systems (Cranes)

(1) Definition:

Overhead handling systems (cranes) are used to lift heavy objects in the vicinity of PWR and BWR spent fuel storage facilities and inside the reactor building. If a heavy object (for example, a shielded cask) were to drop on the spent fuel or on the reactor core during refueling, there could be a potential for overexposure of plant personnel and for release of radioactivity to the environment. Review the overhead handling system, including sling and other lifting devices, and the potential for the drop of a heavy object on spent fuel, including structural effects.

(2) Safety Objective:

To assess the safety margins, and improve margins where necessary, of the overhead handling systems to assure that the potential for dropping a heavy object on spent fuel is within acceptable limits and that the potential radiation dose to an individual does not exceed the guidelines of 10 CFR Part 100.

(3) Status:

Regulatory Guide 1.104, "Overhead Crane Handling Systems for Nuclear Power Plants," was issued for comment in February 1976 and references various industry standards. New applications (construction permit and operating license) are reviewed in accordance with APCSB Branch Technical Position 9-1 which is identical to Regulatory Guide 1.104.

The review of overhead handling systems of operating reactor facilities is performed on a generic basis and has also been identified as a DOR Technical Activity Category A.

(4) References:

1. Regulatory Guide 1.104, "Overhead Crane Handling Systems for Nuclear Power Plants"
2. Standard Review Plan, Branch Technical Position APCSB 9-1, "Overhead Handling Systems for Nuclear Power Plants"
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-22, "Fuel Cask Drop Analysis," April 1977
4. Division of Operating Reactors, DOR Technical Activities, Category A, Item 50, "Control of Heavy Loads Over Spent Fuel," April 1977

(5) Basis for Deletion (Related TMI Task, USI or Other SEP Topic):

- USI A-36, "Control of Heavy Loads Near Spent Fuel" (NUREG-0649)

  The review criteria required by USI A-36 (Standard Review Plan, Section 9.1.4, and NUREG-0554) are identical to the review criteria specified in the References of SEP Topic IX-2 (BTP 9-1 and Regulatory Guide 1.104); therefore, this SEP topic has been deleted.

TOPIC: IX-3 Station Service and Cooling Water Systems

(1) Definition:

Review the station service water and cooling water systems that are required for safe shutdown during normal, operational transient, and accident conditions, and for mitigating the consequences of an accident or preventing the occurence of an accident. These include cooling water systems for reactor system components (components cooling water system), reactor shutdown equipment, ventilation equipment, and components of the emergency core cooling system (ECCS). These systems also include the station service water system, the ultimate heat sink, and the interaction of all the above systems.

The review of these systems includes the pumps, heat exchangers, valves and piping, expansion tanks, makeup piping, and points of connection or interfaces with other systems. Emphasis is placed on the cooling systems for safety-related components such as ECCS equipment, ventilation equipment, and reactor shutdown equipment.

The following specific aspects of those systems will be considered in the review:

(a) Physical separation of redundant cooling water systems that are vital to the performance of engineered safety systems components,

(b) Availability of cooling water to primary reactor coolant pumps,

(c) Requirements for makeup water of cooling water systems,

(d) Effect of water overflow from tanks,

(e) Circulating water system barrier failure protection.

(2) Safety Objective:

To assure that the station service and cooling water systems have the capability, with adequate margin, to meet their design objective. To assure, in particular, that

(a) Systems are provided with adequate physical separation such that there are no adverse interactions among those systems under any mode of operation;

(b) Cooling water is provided to the bearings of the primary reactor coolant pumps by two independent essential service water systems for PWR plants to take credit for core cooling by pump coastdown. In addition, it should be demonstrated that the possibility of simultaneous loss of water in both essential service water systems by valve closure is sufficiently small;

(c) Sufficient cooling water inventory has been provided or that adequate provisions for makeup are available;

(d) Tank overflow cannot be released to the environment without monitoring and unless the level of radioactivity is within acceptable limits;

(e) Vital equipment necessary for achieving a controlled and safe shutdown is not flooded due to the failure of the main condenser circulating water system.

(3) Status:

The station service and cooling water systems of applications currently under review are evaluated in accordance with the Standard Review Plan (Sections 9.2.2 and 10.4.5). Some of the specific concerns identified above are under generic review or have been proposed for a technical activity in the Office of Nuclear Reactor Regulation in accordance with the references below.

(4) References:

1. Letter from R. F. Fraley (ACRS) to L. V. Gossick, Subject: "Analysis of Systems Interactions," November 1, 1976
2. Memorandum from B. C. Rusche to L. V. Gossick, ACRS Subcommittee on Systems Interactions, January 1977
3. Division of Project Management, DPM Technical Activities, Category A, Item DPM-15, "Systems Interactions in Nuclear Power Plants," April 1977
4. Memorandum to R. L. Tedesco, NRC, to D. B. Vassallo, Auxiliary Systems Branch 02 on Yellow Creek Nuclear Plant, Item 010.42, (cooling water for RCP), January 31, 1977
5. Division of Systems Safety, DSS Technical Safety Activities Report, "Cooling Water System Makeup Water Requirements (For Safety Systems)," December 1975
6. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-20, "Flood of Equipment Important to Safety (Generic)," April 1977
7. Division of Operating Reactors, DOR Technical Activities, Category A, Item 15, "Flood of Equipment Important to Safety," April 1977

TOPIC: IX-4 Boron Addition System (PWR)

(1) Definition:

Review the boron addition system (PWR), in particular with respect to boron precipitation during the long-term cooling mode of operation following a loss-of-coolant accident.

(2) Safety Objective:

To assure that boron precipitation will not impair the operability of valves or components in the boron addition system which could compromise its capability to control core reactivity during the normal, transient, or emergency shutdown conditions or that would result in flow blockage through the core during the long-term core cooling mode following a loss-of-coolant accident.

(3) Status:

Operating PWR reactors, with the exception of the Combustion Engineering reactors, have been reviewed and found to be acceptable in regard to boron precipitation following a loss of coolant. There are still certain outstanding issues that need to be resolved on this issue for Combustion Engineering reactors. In regard to the precipitation of boron in the boron addition system in both BWRs and PWRs, certain older plants may not have been reviewed in sufficient detail to assure that system reliability is adequate.

(4) Reference:

Standard Review Plan, Section 9.3.4

TOPIC: IX-5 Ventilation Systems

(1) Definition:

Review the design and operation of ventilation systems whose function is to maintain a safe environment for plant personnel and engineered safety features equipment. For example, the function of the spent fuel pool area ventilation system is to provide ventilation in the spent fuel pool equipment areas, to permit personnel access, and to control airborne radioactivity in the area during normal operation, anticipated operational transients, and following postulated fuel handling accidents. The function of the engineered safety feature ventilation system is to provide a suitable and controlled environment for engineered safety feature components following certain anticipated transients and design basis accidents.

(2) Safety Objective:

To assure that the ventilation systems have the capability to provide a safe environment, under all modes of operation, for plant personnel (10 CFR Part 20) and for engineered safety features (for example, to assure that the diesel room has redundant outside air intakes and removed from the exhaust discharge).

(3) Status:

The ventilation systems of plants under current review (construction permit and operating license applications) are currently evaluated in accordance with the Standard Review Plan. No specific issues or concerns have been identified for operating reactor plants.

(4) References:

Standard Review Plan, Sections 9.4.1 through 9.4.5

TOPIC: IX-6 Fire Protection

(1) Definition:

Review the fire protection program of operating reactor plants to determine whether improvements are required in accordance with the APCSB Technical Position 9.5-1, Appendix A (Reference 2). The fire protection program encompasses the components, procedures, and personnel utilized in carrying out all activities of fire protection and includes such things as fire prevention, detection, annunciation, control, confinement, suppression, extinguishment, administrative procedures, fire brigade organization, inspection and maintenance, training, quality assurance, and testing. The review includes such items as: (1) the use of insulation inside the containment and (2) the consequences of the inadvertent release of hydrogen into the plant.

(2) Safety Objective:

To assure that, in case of a fire within the plant, the integrity of the engineered safety features is not compromised and that the safe shutdown capability and control of the plant are not lost.

(3) Status:

A generic review of fire protection for operating plants is under way. All licensees were requested by letter (May 11, 1976) to submit an evaluation of their fire protection program for that plant in comparison with the APCSB Technical Position 9.5-1. Subsequently, in September 1976, the licensees were provided with Appendix A to the BTP 9.5-1 which presents acceptable alternatives for operating plants.

(4) References:

1. NUREG-0050, "Recommendations Related to Browns Ferry Fire," February 1976
2. Standard Review Plan, Branch Technical Position APCSB 9.5-1, Appendix A, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976"

3. Regulatory Guide 1.120, "Fire Protection Guidelines for Nuclear Power Plants"
4. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-18, "Fire Protection," April 1977
5. Division of Operating Reactors, DOR Technical Activities, Category A, Item 28, "Fire Protection," April 1977
6. Division of Systems Safety, DSS Technical Activities, Category A, Item 32, "Fire Protection," April 1977
7. Letter from R. F. Fraley, ACRS, to L. V. Gossick, Subject: "Analysis of Systems Interactions - Item 6," November 1, 1976

TOPIC: X Auxiliary Feedwater System

(1) Definition:

Review the auxiliary feedwater system, associated instrumentation, and connection between redundant systems. The review includes the aspec of pump drive and power supply diversity (for example, electrical and steam-driven sources), and the water supply sources for the auxiliary feedwater system.

(2) Safety Objective:

To assure that the auxiliary feedwater system can provide an adequate supply of cooling water to the steam generators for decay heat removal in the event of a loss of all main feedwater. Older PWR plants may not meet the requirement for pump drive and power supply diversity.

(3) Status:

Reviews for new license applications are performed in accordance with the Standard Review Plan. This topic is not under active review for operating plants.

(4) References:

1. Standard Review Plan, Section 10.4.9
2. Standard Review Plan, Branch Technical Position APCSB 10-1, "Design Guidelines for Auxiliary Feedwater System Pump Drive and Power Supply Diversity for PWR Plants"

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- TMI Action Plan Task II.E.1.1, "Auxiliary Feedwater System Evaluation" (NUREG-0660)

The TMI-2 accident and subsequent investigations and studies highlighted the importance of the auxiliary feedwater (AFW) system in the mitigation of severe transients and accidents. Since then, the AFW systems have come under close scrutiny by the NRC and many improvements have been recommended to enhance the reliability of AFW systems for all plants. The scope of the review outlined in the SEP

Topic X definition is identical to the scope of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.E.1.1(2), which requires that each PWR plant licensee:

> Perform a deterministic review of the AFW system using the acceptance criteria of Standard Review Plan Section 10.4.9 and associated Branch Technical Position ASB 10-1 as principal guidance.

The review criteria for the evaluations required by Item II.E.1.1(2) are identical to SEP Topic X; therefore, this SEP topic has been deleted.

TOPIC: XI-1 Appendix I

(1) Definition:

A generic review of all operating plants to determine their capability to comply with Appendix I, 10 CFR 50, and to prevent explosions in the gaseous radwaste system is currently underway.

(2) Safety Objective:

To provide assurance that radioactive gaseous effluents from the facility can be kept "as low as reasonably achievable" as defined in Appendix I, 10 CFR Part 50, and to assure adequate control of the mixture of gases in the gaseous radwaste system to prevent explosions.

(3) Status:

A generic review of all operating reactors (ORs) for their capability to conform with Appendix I, 10 CFR Part 50, is currently under way by the Division of Site Safety and Environmental Analysis. Upon the completion of this review, new gaseous and liquid radiological effluent and monitoring Technical Specifications will be issued to all ORs. This will include new Technical Specifications on gaseous radwaste systems which may contain explosive gas mixtures to meet present criteria. The estimated completion date of this review is 1979.

(4) References:

1. 10 CFR Part 20
2. 10 CFR Part 50, Appendix I
3. 10 CFR Part 50, Appendix A
4. 10 CFR Part 50, Appendix A, GDC 60, 61, 63, and 64
5. Standard Review Plan, Section 11.3

(5) Basis for Deletion

Topic XI-1 is being resolved by the following NRR generic topics: (a) A-02, "Appendix I" and (b) B-35, "Confirmation of Appendix I Models." Resolution of these two generic topics will primarily result in Technical Specification changes and may require some minor hardware changes. At present, nothing more than the addition of monitoring instrumentation is foreseen. The implementation of Appendix I will, therefore, not affect the integrated assessment for SEP plants.

In addition, the implementation of Appendix I will result in limiting conditions for operation to assist licensees in keeping the amount of radioactive material released in effluents to unrestricted areas as low as is reasonably achievable. Since licensees are currently restricted in the types and amounts of effluents they can release, implementation of additional restrictions on releases should not impact operation of the plant.

Based on the above, Topic XI-1 has been deleted from the SEP program.

TOPIC: XI-2 Radiological (Effluent and Process) Monitoring Systems

(1) Definition:

Onsite radiological monitoring systems are used to:

(a) Assess the proper functioning of the process and waste treatment systems,

(b) Assure that radioactive releases do not exceed the appropriate guidelines, and

(c) Measure actual releases to evaluate their environmental impact.

There is concern about the adequacy of radiation monitoring systems. A survey of 12 plants has been initiated. The results of this survey will indicate whether this area needs to be reviewed for all operating plants. Re-review would include the monitor's sensitivity, range, location, and calibration techniques.

(2) Safety Objective:

To provide reasonable assurance that the licensee adequately monitors the releases of radioactive materials in liquid and gaseous effluent and that the releases are properly restricted. To provide assurance that the licensee adequately monitors the operation of equipment that contains or may contain radioactive material.

(3) Status:

A technical assistance program has been initiated at Brookhaven National Laboratory with the scope including the above safety objectives.

(4) References:

1. 10 CFR Part 20, Section 20.106
2. 10 CFR Part 50, Section 50.36a
3. 10 CFR Part 50, Appendix A, GDC 60, 61, 63, and 64
4. 10 CFR Part 50, Appendix I
5. Standard Review Plan, Section 11.5

(5) Basis for Deletion

Topic XI-2 is being resolved by the following NRR generic topics: (a) A-02, "Appendix I" and (b) B-67, "Effluent and Process Monitoring Instrumentation." A-02 is discussed in Topic XI-1. Generic item B-67 was subdivided into four subtasks. The staff believes that events since the inception of B-67 have largely addressed the identified concerns or changed its thinking in regard to their safety significance. The description and bases for deletion of each subtask are presented below.

Subtask 1: Monitoring of Radioactive Materials Released in Effluents

Item III.D.2.1, Radiological Monitoring of Effluents requires an NRR evaluation of modifying effluent monitoring design criteria based on TMI-2 and their experiences.

Item II.F.1(1), Noble Gas Effluent Monitor of Clarification of the TMI Action Plan Requirements (NUREG-0737) is being implemented to require adequate monitoring capability during accident conditions.

Subtask 2: Control of Radioactive Materials Released in Effluents

The purpose of this subtask was to review plant operating histories and prepare NUREG reports documenting the evaluations and recommending solutions to identified problems.

Various staff actions since 1978 (including NUREG reports and IE Bulletins) have resulted in the staff conclusion that no continuing need for additional staff guidance exists.

Subtask 3: Effects of Accidental Liquid Releases on Nearby Water Supplies

The purpose of this task was to perform a generic analysis of the consequences of liquid tank failures for those plants which received their license prior to issuance of the Standard Review Plan (SRP).

Experience in performing SRP analyses for newer plants has indicated that it is highly unlikely that radioactive concentrations in the nearest potable water supply could exceed 10 CFR Part 20 values.

Subtask 4: Performance of Solid Waste Systems

The purpose of subtask 4 was to perform an industry-wide survey to determine the extent to which power plants could process wastes and to develop plans for upgrading existing systems or adding new systems.

The NRC position relative to a requirement for an operable installed solid radwaste system has changed and, therefore, this subtask is no longer appropriate.

For the above reasons, Issue B-67 is being deleted from the NRR list of generic issues. Since Issue B-67 is being deleted, only Generic Issue A-02, "Appendix I" is appropriate to this topic.

The resolution of Issue A-02 is described in the Basis for Deletion for Topic XI-1. Topic XI-2 is being deleted from the SEP program for the same reasons.

TOPIC: XIII-1 Conduct of Operations

(1) Definition:

The organization, administrative controls, and operating experience will be reviewed. The existing organization and administrative controls will be compared with Standard Technical Specifications and guidance provided in Regulatory Guides 1.8 and 1.33 to determine the adequacy of the staff to protect the plant and to operate safely in routine, emergency, and long-term postaccident circumstances. The plant operating history will be reviewed to assess the combination of staff, operating controls and alarms, and administrative controls, in particular plant procedures, emergency planning, and offsite preparedness, to determine whether additional staff, qualifications, or administrative controls will be required for continued safe operation.

(2) Safety Objective:

To obtain reasonable assurance that the plant has enough people, with sufficient training and experience, and has administrative controls adequate to specify proper operation in routine, emergency, and postaccident conditions.

(3) Status:

Most of the older plants have staff members that meet the experience and educational requirements given in ANSI N18.1-1971 (endorsed by Regulatory Guide 1.8); however, a comparison against current criteria for the composite staff has not been made. These plants have provided training for subsequent plant staffs, and plant experience has, in general, demonstrated safe design and operation. Operating experience review is ongoing, and has been, in general, favorable. However, an analysis of this experience for trends, common elements, and potential hidden problems has not been systematically performed.

A review of Section VI of operating reactor licensees' Technical Specifications was begun in 1974 using Section VI of the Standard Technical Specifications (STS) as a model. As of September 1975, these reviews had been completed and the plants licensed prior to this time had been found to: (1) be acceptable and upgrading was not required, (2) require upgrading of only the reporting requirements, or (3) require improvement to be comparable to the STS model. Plants licensed after September 1975 have been reviewed against the STS model. Further review of Section VI, therefore, will not be required.

Emergency plans submitted at the operating-license stage complied with 10 CFR 50, Appendix E, 1970; however, these plans are not consistent with the guidance given in new Regulatory Guide 1.101, Revision 1, 1977.

(4) References:

1. Regulatory Guides
   1.8, "Personnel Selection and Training"
   1.33, "Quality Assurance Program Requirements (Operations)"
2. American National Standards Institute, ANSI N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel"
3. American National Standards Institute, ANSI N18.7-1972 Revised, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants"
4. Standard Technical Specifications, Section VI
5. 10 CFR Part 50, Appendix E
6. Regulatory Guide 1.101, Rev. 1, "Emergency Planning for Nuclear Power Plants"
7. Standard Review Plan, Section 13.3
8. NUREG 75/111, "Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans In Support of Fixed Nuclear Facilities," October 1975
9. Environmental Protection Agency, "EPA Manual of Protective Action Guides and Protective Action for Nuclear Incidents," September 1975
10. Memorandum of Understanding, NRR and Office of State Programs on State and Local Preparedness, March 10, 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) TMI Action Plan Task I.C.6, "Procedures for Verification of Correct Performance of Operating Activities," (NUREG-0737)

Under TMI Task I.C.6, a review of licensee procedures will be conducted to assure that an effective system of verifying the correct performance of operating activities exists. The purpose of this review is to provide a means of reducing human errors and improving the quality of normal operation. References cited for this review are ANSI Standard N18.7-1972 (ANS 3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," and Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)." These are the same references cited for Topic XIII-1.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Preparedness - Short-Term," and Task III.A.2, "Improving Licensee Emergency Preparedness - Long-Term" (NUREG-0660 and NUREG-0737)

Under Task III.A.1, a review of 10 CFR Part 50, Appendix E backfit requirements is being conducted in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." The scope of NUREG-0654 covers Standard Review Plan, Section 13.3, and NUREG 75/111.

Regulatory Guide 1.101 has been deleted and has been superseded by an amended Appendix E to 10 CFR Part 50 (45 FR 55410, August 19, 1980). Under Task III.A.2, a review of licensee's emergency preparedness plans with respect to amended Appendix E will be conducted in accordance with NUREG-0654.

The evaluations required by TMI Tasks I.C.6, III.A.1, and III.A.2 are identical to SEP Topic XIII-1; therefore, this SEP topic has been deleted.

TOPIC: XIII-2 Safeguards/Industrial Security

(1) Definition:

Industrial security will be included under the scope of the operations review. Design features to assess the plant's capability to prevent sabotage and protect the operating unit(s) at dual or three-unit sites with unit(s) under construction will be included. Protective measures will be balanced against the sabotage threat. Fuel accountability will also be reviewed to assure that adequate inventory control procedures exist and the required records are kept.

(2) Safety Objective:

To determine that the plant has adequate security forces, design features, procedures and plans, and other administrative controls to meet the postulated sabotage threat. To assure that the fuel is adequately accounted for, that proper records are maintained, and the required reports are made.

(3) Status:

Each licensee currently has a security program and a fuel accountability program. Revised 10 CFR 73.55 has been published and submittals in accordance with its provisions were due May 25, 1977. These submittals are currently being evaluated.

(4) References:

1. 10 CFR Part 70
2. 10 CFR Part 73
3. Standard Technical Specifications, Section VI

TOPIC: XV-1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

(1) Definition:

Review the assumptions, calculational models used and consequences of postulated accidents which involve an unplanned increase in heat removal. An excessive heat removal, that is, a heat removal rate in excess of the heat generation rate in the core, causes a decrease in moderator temperature which increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. If clad failure is calculated to occur, determine that offsite dose consequences are acceptable.

(2) Safety Objective:

To assure that pressures in the reactor coolant and main steam systems are limited in order to protect the reactor coolant pressure boundary from over ...surization and that fuel rod cladding failure as a result of departure from nucleate boiling ratio is limited.

(3) Status:

During each reload review by the staff, the previously determined limiting transient is reviewed to determine if new core parameters are more restrictive than the reference analysis parameter values.

(4) References:

Standard Review Plan, Sections 15.1.1 through 15.1.4

TOPIC: XV-2 Spectrum of Steam System Piping Failures Inside and Outside of Containment (PWR)

(1) Definition:

Review the assumptions, including use of nonsafety-grade equipment and concurrent steam generator or tube failure or blowdown of more than one steam generator, calculational models used, and consequences of postulated accidents which cause an increase in steam flow. The excessive steam flow reduces system temperature and pressure which increases core reactivity and can lead to a decrease of shutdown margin and departure from nucleate boiling ratio.

(2) Safety Objective:

To assure that (1) pressure in the reactor coolant and main steam lines is limited in order to protect the reactor coolant pressure boundary from overpressurization, (2) fuel damage is sufficiently limited so that the core will remain in place and intact with no loss of core cooling capability, (3) doses at the nearest exclusion area boundary are a small fraction of 10 CFR Part 100 guidelines, (4) ambient conditions do not exceed equipment qualification conditions (particularly nonsafety-grade equipment used to mitigate the accident), (5) the thermal and stress transients do not damage the reactor vessel, and (6) systems necessary for safe shutdown are not damaged by the accident.

(3) Status:

Investigation of the effects of high-energy line failures outside containment on other equipment was initiated as a generic issue in 1971 and all but a few facilities have been completed. New acceptance criteria have evolved during the review period. There was no similar investigation for failures inside containment. No reviews on operating plants of the effects on the reactor of concurrent steam generator or tube failure, or of blowdown of more than one steam generator have been performed.

(4) Reference:

Standard Review Plan, Section 15.1.5

TOPIC: XV-3 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulatory Failure (Closed)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve a decrease in secondary heat removal. The decrease in heat removal causes a suddent increase in system pressure and temperature.

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

The consequences associated with these transients are compared during each reload review to the consequences found to be acceptable during previous reload reviews.

(4) References:

Standard Review Plan, Sections 15.2.1 through 15.2.5

TOPIC: XV-4 Loss of Nonemergency AC Power to the Station Auxiliaries

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve the loss of nonemergency ac power (loss of offsite power or onsite ac distribution system) to station auxiliaries (for example, reactor coolant circulation pumps). This power loss will, within a few seconds, cause the turbine to trip and reactor coolant system to be isolated, which in turn causes the coolant pressure and temperature to increase.

(2) Safety Objective:

To assure that the pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

During each reload review by the staff, the previously determined limiting transient is reviewed to determine if new core parameters are more restrictive than the reference analysis parameter values.

(4) Reference:

Standard Review Plan, Section 15.2.6

TOPIC: XV-5 Loss of Normal Feedwater Flow

(1) Definition:

Review the assumptions, calculatic l models used, and consequences of the postulated loss of feedwater flow accidents, which cause an increase in coolant pressure and temperature.

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

The consequences associated with these transients are compared during each reload review to the consequences found to be acceptable during previous reload reviews.

(4) Reference:

Standard Review Plan, Section 15.2.7

TOPIC: XV-6 Feedwater System Pipe Breaks Inside and Outside Containment (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve feedwater line breaks of different sizes. A feedwater line break, depending on size, may cause reactor system heatup (by reducing feedwater flow to the steam generator), or cooldown (by excessive energy discharge through the break).

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained and that any radioactivity release would result in doses at the site boundary well within 10 CFR Part 100 guidelines.

(3) Status:

The identification of the most limiting transients and the consequences associated with these transients is evaluated during each reload review by the staff.

(4) Reference:

Standard Review Plan, Section 15.2.8

TOPIC: XV-7 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

(1) Definition:

Review the assumptions, calculational models, and consequences of seizure of the rotor or break of the shaft of a reactor coolant pump in a PWR or recirculation pump in a BWR. These accidents result in a sudden decrease in core coolant flow and corresponding degradation of core heat transfer and, in a PWR, an increase in primary system pressure. If clad failure is calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To assure that the consequences of a reactor coolant pump rotor seizure or reactor coolant pump shaft break are acceptable; that is, that no more than a small fraction of the fuel rods fail, that the radiological consequences are a small fraction of 10 CFR Part 100 guidelines, and that the system pressure is limited in order to protect the reactor coolant pressure boundary from overpressurization.

(3) Status:

Reviewed during each reload only if there is reason to believe that results would be different from the reference analysis; that is, only if a change in core parameters invalidates previous analyses.

(4) Reference:

Standard Review Plan, Section 15.3.3

TOPIC: XV-8 Control Rod Misoperation (System Malfunction or Operator Error)*

(1) Definition:

Review the licensee's description of rod position, flux, pressure, and temperature indication systems and the actions initiated by those systems which can mitigate the effects or prevent the occurrence of various misoperations. Review the descriptions of the input calculations and the calculational models used and the justification of their validity and adequacy. A transient of this type can result in achieving fuel melt temperatures and potential fuel damage.

(2) Safety Objective:

To assure that the consequences of this event do not exceed specified fuel design limits and that the protection system action be initiated automatically.

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*Reviewed for PWRs only; Standard Review Plan, Sections 15.4.1 and 15.4.2 cover BWRs and no additional areas considered.

(3) Status:

Reviewed during reload, Technical Specifications revised to compensate for changes in analytical results.

(4) Reference:

Standard Review Plan, Section 15.4.3

TOPIC: XV-9 Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate

(1) Definition:

Review BWRs for (1) startup of an idle recirculation pump and (2) a flow controller malfunction causing increased recirculation flow. Review PWRs with loop isolation valves for startup of a pump in an initially isolated inactive reactor coolant loop where the rate of flow increase is limited by the rate at which isolation valves open. For PWRs without loop isolation valves, review startup of a pump in any inactive loop. If clad failures are calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To verify that the plant responds in such a way that the criteria regarding fuel damage and system pressure are met (that is, no more than a small fraction of the fuel rods fail, that radiological consequences are a small fraction of 10 CFR Part 100 guidelines, and that the system pressure is limited in order to protect the reactor coolant pressure boundary from overpressurization.)

(3) Status:

PWRs reviewed against the final safety analysis report, BWR reviewed at each reload, Technical Specifications required to preclude exceeding safety limits during transients.

(4) Reference:

Standard Review Plan, Sections 15.4.4 and 15.4.5

TOPIC: XV-10 Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of moderator dilution. An accident of this type could result in a departure from nucleate boiling and a loss of shutdown margin.

(2) Safety Objective:

To confirm that the plant responds to the events in such a way that the criteria regarding fuel damage and system pressure are met and adequate time allowed for the operator to terminate the dilution before the shutdown margin is reduced. (Reactor coolant pressure and main steam pressure should be limited in order to protect the reactor coolant pressure boundary from overpressurization.) (Operator action must be initiated within 30 minutes following this event if refueling, and within 15 minutes during other modes of operation.)

(3) Status:

Only reviewed during initial operating-license review and not thereafter. The consequences may not have been calculated in accordance with current practice.

(4) Reference:

Standard Review Plan, Section 15.4.6

TOPIC: XV-11 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (BWR)

(1) Definition:

Review the spectrum of misloading events analyzed to verify that the worst situation undetectable by incore instrumentation has been identified. This review will include an assessment of the plant's offgas and steam line radiation monitors to detect fuel damage and their capability to automatically isolate the offgas system when necessary.

(2) Safety Objective:

To assure that a misloaded assembly is detected and if undetected will not result in exceeding fuel safety limits or radioactive releases.

(3) Status:

Reviewed during reloads, Technical Specifications developed to limit consequences of worst misloaded assembly to small fraction of 10 CFR Part 100 guidelines. Technical Specifications setpoints for radiation monitors alarm/isolation signals have been found deficient and have been updated on a case-by-case basis for several plants.

(4) Reference:

Standard Review Plan, Section 15.4.7

TOPIC: XV-12 Spectrum of Rod Ejection Accidents (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences, including radiological consequences, of PWR control rod ejection accidents, and review the Technical Specifications regarding control of reactivity worth and technical specifications on primary to secondary leakage. Ejection of a control element assembly from the core can occur if the control element drive mechanism housing or the nozzle on the reactor vessel head breaks off circumferentially. The ejection of a control element assembly by the reactor coolant system pressure can cause a severe reactivity excursion. This accident may result in high doses for those plants where fuel failures are postulated to occur as a result of the accident. This accident usually determines the maximum allowable steam generator leak rate.

(2) Safety Objective:

To ensure that if a control element assembly ejection occurs, core damage is minimal, no additional reactor coolant pressure boundary failures occur, the calculated radial average energy density is limited to 280 cals/gm at any axial fuel location in any fuel rod, and that the radiological consequences will not exceed appropriate limits.

(3) Status:

Releases through the containment and/or steam generator leaks are analyzed for current plants, but were not reviewed routinely for older plants. Many of the operating plants have no leak Technical Specifications or they are excessively high. During each reload by the staff the previously determined limiting transient is reviewed to determine if the new ejected rod worth is more restrictive than the reference analysis values.

(4) References:

1. Standard Review Plan, Section 15.4.8
2. Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors"

TOPIC: XV-13 Spectrum of Rod Drop Accidents (BWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of BWR control rod drop accidents and review the Technical Specifications regarding control of rod activity worth. An uncoupled rod may hang up in the core when the control rod drive is withdrawn and drop later when the consequences of a rapid control rod withdrawal are most severe. An analysis of the radiological consequences from this accident will be included.

(2) Safety Objective:

To limit the effects of a postulated control rod drop to the extent that reactor coolant pressure boundary stresses are not exceeded and core damage is minimal. To assure that the radial average fuel rod enthalpy at any axial location in any fuel rod is limited to less than 280 cals/gm following the worst reactivity excursion and to assure that the radiological consequences do not exceed appropriate guidelines.

(3) Status:

The potential for and reactivity consequences of an accidental control rod drop are now routinely evaluated prior to issuance of an operating license and any time thereafter when changes could affect the accident results or probability of occurrence. Radiological consequences may not have been calculated in accordance with present practice.

(4) Reference:

Standard Review Plan, Section 15.4.9

TOPIC: XV-14 Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory

(1) Definition:

Review the assumptions, calculational models used, and consequences of actuation of the high pressure coolant injection system or faulty operation of the volume control system. The chemical and volume control system regulates both the chemistry and the quantity of coolant in the reactor coolant system. Changing the boron concentration in the reactor coolant system is a part of normal plant operation, compensating for long-term reactivity effects. Actuation of these systems could increase the volume of coolant within the reactor coolant pressure boundary (RCPB) causing a high water level, possible high power level, and high or low pressure. If clad failure is calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To assure that water added to the RCPB does not cause transients that exceed RCPB pressure limits or result in unacceptable fuel damage. No activity is released during the transient, but the transient may subsequently result in increased radioactivity in gaseous releases during normal operation.

(3) Status:

This transient is now routinely analyzed prior to issuance of an operating license and any time thereafter when proposed changes would affect the transient results. Radiological consequences may not have been calculated in accordance with current practice.

(4) Reference:

Standard Review Plan, Section 15.5.1

TOPIC: XV-15 Inadvertent Opening of a PWR Pressurizer Safety/Relief Valve or a BWR Safety/Relief Valve

(1) Definition:

Review the assumptions, calculational models used, and consequences of inadvertent opening of a PWR pressurizer safety/relief valve or a BWR safety/relief valve. Loss of reactor coolant inventory and depressurizing action of the reactor coolant system can occur if the PWR pressurizer safety/relief valve or the BWR safety/relief valves open spuriously, or open when required but fail to reclose properly.

(2) Safety Objective:

To preserve fuel cladding integrity during reactor coolant system depressurization transients resulting from faulty operation of a relief or safety valve while at rated power.

(3) Status:

The transient is now evaluated prior to issuance of an operating license and any time thereafter when proposed changes could affect the transient results.

(4) References:

1. Standard Review Plan, Section 15.5.1
2. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants"

TOPIC: XV-16 Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment

(1) Definition:

Review the assumption, calculational models used, and radiological consequences of failure of small lines carrying primary coolant outside containment and review the Technical Specifications associated with primary coolant radioactivity concentrations, isolation valve closure times, and isolation valve leakage limits. In the event of a rupture of any component in the instrument lines outside primary containment, primary coolant and any radioactivity contained in the coolant or released to the coolant during the transient will be released if the instrument lines are connected to the reactor coolant pressure boundary. Primary coolant sample lines if broken outside primary containment can also allow coolant and radioactivity in the coolant to escape in the same manner. When these lines discharge to secondary containment, the integrity of the secondary containment and the efficiency of the filtration systems must be determined.

(2) Safety Objective:

To assure that any release of radioactivity to the environment is substantially below the guidelines of 10 CFR 100.

(3) Status:

The radiological consequences of small line breaks outside of primary containment have been evaluated routinely since 1970 prior to issuance of operating licenses, but have not always included the effects of iodine spikes during the depressurization transient.

(4) References:

1. Regulatory Guide 1.11, "Instrument Lines Penetrating Primary Reactor Containment"
2. 10 CFR Part 50, Appendix A, GDC 55 and 56
3. Standard Review Plan, Section 15.6.2

TOPIC: XV-17 Radiological Consequences of Steam Generator Tube Failure (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of a steam generator tube failure with and without loss of offsite power and review the Technical Specifications associated with coolant activity concentrations. Steam generator tube failures allow escape of reactor coolant into the main steam system and to the environment. An analysis of the radiological consequences of this accident will be included.

(2) Safety Objective:

To assure that the plant responds in a proper manner to this accident, including appropriate operator actions, and to assure that radioactivity released following steam generator tube failure(s) is a small fraction of the 10 CFR 100 guidelines and within 10 CFR 100 for the case of a coincident iodine spike.

(3) Status:

The iodine release mechanism may not have been analyzed in accordance with present assumptions and methods for some of the older PWRs. Some operating plants do not have iodine activity limits in their Technical Specifications or have inappropriately high limits.

(4) References:

1. Standard Review Plan, Section 15.6.3
2. Regulatory Guide 1.5, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors"

TOPIC: XV-18 Radiological Consequences of Main Steam Line Failure Outside Containment

(1) Definition:

Review the assumptions, calculational models used, and consequences of failure of a main steam line outside containment and review the Technical Specifications associated with primary coolant activity concentrations and main steam isolation valve closure times.

(2) Safety Objective:

A steam line break outside containment allows radioactivity to escape to the environment. To limit the release of radioactivity to the environment to well within the guidelines of 10 CFR 100 in the event of a large steam line break, the primary coolant radioactivity must be appropriately limited by Technical Specifications.

(3) Status:

Some operating plants do not have appropriate coolant activity Technical Specifications.

(4) Reference:

Standard Review Plan, Section 15.6.4

TOPIC: XV-19 Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

(1) Definition:

Review the licensee's analyses of the spectrum of loss-of-coolant accidents (LOCAs) including break locations, break sizes, and initial conditions assumed, the evaluation model used, failure modes, radiological consequences, acceptability of auxiliary systems, functional capability of the containment, and the effects of blowdown loads. LOCAs are postulated breaks in the reactor coolant pressure boundary resulting in a loss of reactor coolant at a rate in excess of the capability of the reactor coolant makeup system. LOCAs result in excessive fuel damage or melt unless coolant is replenished.

(2) Safety Objective:

To assure that the consequences of loss-of-coolant accidents are acceptable; that is, that the requirements of 10 CFR 50.46 and Appendix K to 10 CFR 50 are met, that the radiological consequences of a design basis loss-of-coolant accident from containment leakage and the radiological consequences of leakage from engineered safety features outside containment are acceptable, and the structural effects of blowdown are acceptable.

(3) Status:

Emergency core cooling system (ECCS) evaluation is a generic item which is currently under review or is complete for all operating reactors (La Crosse and San Onofre have stainless steel cores and have analyses completed to show conformance with the Interim Acceptance Criteria). Related generic items currently under review are reevaluations for increased vessel head fluid temperatures in W PWRs, effects of core flow on BWR LOCA analyses, GE ECCS input errors, and non-jet pump BWR core spray cooling coefficients. Radiological consequences are not routinely rereviewed.

(4) Reference:

Standard Review Plan, Section 15.6.5 and its Appendices

TOPIC: XV-20 Radiological Consequences of Fuel-Damaging Accidents (Inside and Outside Containment)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated fuel damaging accidents inside and outside containment and review Technical Specifications associated with fuel handling and ventilation system and filter systems, including interlocks on fuel movement and damage from fuel cask drop and tipping. Include in the review the assumed activity available for release, decontamination factors, filter efficiencies, activity transport mechanisms and rates, ventilation system potential release pathways, and calculated doses.

(2) Safety Objective:

To assure that offsite doses resulting from fuel damaging accidents, resulting from fuel handling, or dropping a heavy load on fuel are well within the guideline values of 10 CFR Part 100.

(3) Status:

The radiological consequences of fuel handling accidents inside containment are currently being performed as a generic review for PWRs. The radiological consequences of fuel damaging accidents outside containment of operating plants are only evaluated if Technical Specifications are reviewed.

(4) References:

1. Standard Review Plan, Section 15.7.4
2. Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors"

TOPIC: XV-21 Spent Fuel Cask Drop Accidents

(1) Definition:

Review the potential for spent fuel cask drops, the damage which could result from cask drops, and the radiological consequences of a cask drop from fuel damaged within the cask under conditions exceeding the design basis impact on the cask.

(2) Safety Objective:

To assure that the damage to fuel within the casks and radiological consequences resulting from a cask drop are acceptable or that acceptable measures have been taken to preclude cask drops.

(3) Status:

Fuel cask drop analysis is a generic item which has been completed on some plants or is currently under review for all other operating reactors.

(4) References:

1. Standard Review Plan, Section 15.7.4
2. Regulatory Guide 1.25 "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors"
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book)

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-36, "Control of Heavy Loads Near Spent Fuel" (NUREG-0649)

  The review criteria required by USI A-36 (Standard Review Plan, Section 15.7.5) are identical to the review criteria specified in the References of SEP Topic IX-2; therefore, this SEP topic has been deleted.

TOPIC: XV-22 Anticipated Transients Without Scram

(1) Definition:

Review the postulated sequences of events, analytical models, values of parameters used in the analytical models, and the predicted results and consequences of events in which an anticipated transient occurs and is not followed by an automatic reactor shutdown (scram). Analyses of the radiological consequences for these transients will be included. Failure of the reactor to shut down quickly during anticipated transients can lead to unacceptable reactor coolant system pressures and to fuel damage.

(2) Safety Objective:

To assure that the reliability of the reactor shutdown systems is high enough so that anticipated transient without scram (ATWS) events need not be considered or to assure that the consequences of ATWS events are acceptable; that is, that the reactor coolant system pressure, fuel pressure, fuel thermal and hydraulic performance, maximum containment pressure, and radiological consequences are within acceptable limits.

(3) Status:

ATWS is a generic topic currently under review to determine a position for all power reactors. BWR licensees have been requested to install reactor coolant pump trips as a short-term program measure. All licensees have submitted descriptions of the applicability of vendor generic ATWS reports for their plants. The schedule for review of Class C plants, which includes those plants designated for Phase II of SEP, has not yet been developed.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book)
2. WASH 1270, "Technical Report on Anticipated Transients Without Scram for Water-Cooled Power Reactors," September 1973
3. Standard Review Plan, Section 15.8 and Appendix

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-9, "Anticipated Transients Without Scram" (NUREG-0606)

  The reference cited in this topic, that is, NUREG-0328, was the precursor of USI A-9. The evaluation required for USI A-9 is identical to SEP Topic XV-22; therefore, this SEP topic has been deleted.

TOPIC: XV-23 Multiple Tube Failures in Steam Generators

(1) Definition:

Assess the effects of multiple steam generator tube failures (ranging from leaks to double-ended ruptures) as a result of pressure differentials that may occur following a loss-of-coolant accident (LOCA), steam line break, or anticipated transient without scram (ATWS) events.

(2) Safety Objective:

Assure that the reflood of the core following a LOCA is possible and that the radiological consequences following these accidents are within the 10 CFR Part 100 guidelines.

(3) Status:

The consequences of multiple tube failures have not been analyzed for any plant at the licensing stage. Work has been done for some operating plants, but ultimate goals have yet to be set.

(4) References:

1. Prairie Island Nuclear Station, Docket Nos. 50-282 and 50-306
2. Turkey Point Plant, Docket Nos. 50-250 and 50-251
3. Surry Power Stations, Units 1 and 2, Docket Nos. 50-280 and 50-281

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-3, A-4, A-5, "Westinghouse, Combustion Engineering, Babcock and Wilcox Steam Generator Tube Integrity" (NUREG-0649)

Two of the tasks of USI A-3, A-4, A-5 are as follows:

1. Analyses of LOCA with Concurrent Steam Generator Tube Failures
2. Analyses of Main Steam Line Break

The analyses required by these two tasks in USI A-3, A-4, A-5 cover two of the three events specified in the Definition.

(b) USI A-9, "Anticipated Transients Without Scram" (NUREG-0606)

Pressure differentials resulting from ATWS events have been determined to be no greater than those resulting from main steam line break events (NUREG-0460, Volume 2, Appendix V). The analysis for ATWS event is, therefore, covered under USI A-3, A-4, and A-5.

The evaluation required for USI A-3, A-4, A-5 is identical to SEP Topic XV-23; therefore, this SEP topic has been deleted.

TOPIC: XV-24 Loss of All AC Power

(1) Definition:

Review plant systems to determine that following loss of all ac power (onsite and offsite) the reactor is shut down and core cooling can be initiated. Loss of all ac power causes loss of most emergency equipment and instrumentation.

(2) Safety Objective:

To assure that with only dc power, equipment design, diversity, and operator action are sufficient to initiate core cooling within a short time period (typically 20 minutes).

(3) Status:

Not an explicit SRP topic. Availability of some ac power is assumed in all accident/transient analyses. Topic may be considered as an auxiliary fuel pump or reactor core isolation cooling pump diversity spinoff.

(4) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

USI A-44, "Station Blackout" (NUREG-0606)

The problem description of USI A-44 is identical to the Definition of SEP Topic XV-24, and the review of USI A-44 would be the same as Topic XV-24; therefore, this SEP topic has been deleted.

TOPIC: XVI Technical Specifications

(1) Definition:

The existing Technical Specifications, associated with SEP topics, will be compared with the Standard Technical Specifications for deviations. Where significant differences exist, they will be identified and considered for upgrading. The bases for the specifications will be examined including trip setpoints and accounting for nuclear uncertainty. Where significant voids occur in existing specifications, appropriate values will be identified and considered for upgrading.

(2) Safety Objective:

To assure that the safety limits and operational safety measures are sufficiently specified for the plant to minimize the probability of accidents that could result from equipment failure, misoperation, or human error.

(3) Status:

See Topic XIII-1, "Conduct of Operations" for Section VI status. The other sections of the Technical Specifications are reviewed only to the extent that reloads, license amendments, or generic problems require.

(4) References:

1. Standard Technical Specifications; Regulatory Guide 1.8, "Personnel Selection and Training," and Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)"
2. Standard Review Plan
3. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Chapter 16
4. 10 CFR Part 50, Section 50.36

TOPIC: XVII Operational Quality Assurance Program

(1) Definition:

Review the Quality Assurance (QA) Program with respect to safe and reliable operation of the plant.

(2) Safety Objective:

Since 1973, significant new guidance for operational QA programs in the form of Regulatory Guides and WASH documents has been issued describing how to meet the criteria of 10 CFR Part 50, Appendix B. The objective of this guidance is to assure that operation, maintenance, modification, and test activities do not degrade the capability of safety-related items to perform their intended functions.

(3) Status:

Generic review for compliance with current standards is under way. As of May 1977, 50 of the 63 operating plants have QA programs which meet current criteria. The 13 remaining plants are currently under review, with an estimated completion date of July 1977.

(4) References:

1. 10 CFR Part 50, Appendix B
2. WASH-1283, Revision 1, "Guidance on Quality Assurance Requirements During Design and Procurement Phase of Nuclear Power Plants," May 24, 1974
3. WASH-1284, "Guidance on Quality Assurance Requirements During the Operations Phase of Nuclear Power Plants," October 26, 1973

4. WASH-1309, "Guidance on Quality Assurance Requirements During the Construction Phase of Nuclear Power Plants," May 10, 1974
5. American National Standards Institute, ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," February 19, 1976

U.S. Nuclear Regulatory Commission reports cited under "Basis for Deletion" include:

NUREG-75/111	Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans in Support of Fixed Nuclear Facilities" (Reprint of WASH-1293), Oct. 1975.
NUREG-0153	"Staff Discussion of 12 Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR staff," 1976.
NUREG-0313	"Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," July 1977.
NUREG-0328	"Regulatory Licensing: Status Summary Report" (Pink Book).
NUREG-0371	"Approved Category A Task Action Plans," Nov. 1977.
NUREG-0410	"NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants, Report to Congress," Dec. 1977.
NUREG-0460	"Anticipated Transients Without Scram for Light Water Reactors," Vol. 2, Apr. 1978.
NUREG-0471	"Generic Task Problem Descriptions - Category B, C, and D Tasks," Sept. 1978.
NUREG-0484	"Methodology for Combining Dynamic Responses," May 1980.
NUREG-0510	"Identification of Unresolved Safety Issues Relating to Nuclear Power Plants--A Report to Congress 1979," Jan. 1979.
NUREG-0554	"Single-Failure-Proof Cranes for Nuclear Power Plants," May 1979.
NUREG-0577	"Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," Sept. 1979.
NUREG-0606	"Unresolved Safety Issues Summary," issued quarterly.
NUREG-0609	"Asymmetric Blowdown Loads on PWR Primary Systems, Resolution of Generic Task Action Plan A-2," Jan. 1981.
NUREG-0649	"Task Action Plan for Unresolved Safety Issues Related to Nuclear Power Plants," Feb. 1980.

NUREG-0654 "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Feb. 1980.

NUREG-0660, Rev. 1 "NRC Action Plan Developed as a Result of the TMI-2 Accident," Vols. 1 and 2, May 1980, Rev. 1, Aug. 1980.

NUREG-0691 "Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," Sept. 1980.

NUREG-0705 "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plants," Mar. 1981.

NUREG-0737 "Clarification of TMI Action Plan Requirements," Nov. 1980.

NUREG-0800 "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," July 1981 (formerly NUREG-75/087).

NUREG/CR-1321 "Final Report - Phase I. Systems Interaction Methodology Applications Program," Apr. 1980.

APPENDIX B

SEP TOPICS DELETED BECAUSE THEY ARE COVERED BY A TMI TASK, UNRESOLVED SAFETY ISSUE (USI), OR OTHER SEP TOPIC[1,2]

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[1]See "Basis for Deletion" in Appendix A under applicable SEP topic.
[2]Letter from G. C. Lainas (NRC) to all SEP licensees, Subject: Deletion of Systematic Evaluation Program Topics Covered by Three Mile Island NRC Action Plan, Unresolved Safety Issues, or Other SEP Topics, May 1981.

SEP Topic No	SEP Title	TMI, USI, or SEP No.	TMI, USI, or SEP Title
II-2.B	Onsite Meteorological Measurements Program	TMI II.F.3 TMI III.A.1	Instrumentation for Monitoring Accident Conditions Improve Licensee Emergency Preparedness - Short Term
II-2.D	Availability of Meteorological Data in the Control Room	TMI II.F.3 TMI III.A.1 TMI I.D.1	Instrumentation for Monitoring Accident Conditions Improve Licensee Emergency Preparedness - Short Term Control Room Design Reviews
III-8.D	Core Supports and Fuel Integrity	USI A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant System
III-9	Support Integrity	USI A-12 USI A-7 USI A-24 USI A-46 SEP III-6 SEP V-1	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports Mark I Containment Long-Term Program Environmental Qualification of Safety-Related Equipment Seismic Qualification of Equipment in Operating Plants Seismic Design Considerations Compliance With Codes and Standards (10 CFR Part 50, Section 50.55a)
III-11	Component Integrity	USI A-46 USI A-2 SEP III-6	Seismic Qualification of Equipment in Operating Plants Asymmetric Blowdown Loads on Reactor Primary Coolant Seismic Design Considerations
III-12	Environmental Qualification of Safety-Related Equipment	USI A-24	Qualification of Safety-Related Equipment
V-3	Overpressurization Protection	USI A-26	Reactor Vessel Pressure Transient Protection
V-8	Steam Generator Integrity	USI A-3, A-4, A-5	Westinghouse, Combustion Engineering, and Babcock and Wilcox Steam Generator Tube Integrity
V-13	Waterhammer	USI A-1	Waterhammer
VI-2.A	Pressure-Suppression-Type BWR Containments	USI A-7	Mark I Containment Long-Term Program
VI-2.B	Subcompartment Analysis	USI A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant System
VI-5	Combustible Gas Control	TMI II.B.7 USI A-48	Analysis of Hydrogen Control Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment
VI-7.E	Emergency Core Cooling System Sump Design and Test for Recirculation Mode Effectiveness	USI A-43	Containment Emergency Sump Reliability
VI-8	Control Room Habitability	TMI III.D.3.4	Control Room Habitability Requirements
VII-4	Effects of Failure in Nonsafety-Related Systems on Selected Engineered Safety Features	USI A-47 USI A-17	Safety Implications of Control Systems Systems Interactions in Nuclear Power Plants
VII-5	Instruments for Monitoring Radiation and Process Variables During Accidents	TMI II.F.1 TMI II.F.2 TMI II.F.3	Additional Accident Monitoring Instrumentation Identification of and Recovery From Conditions Leading to Inadequate Core Cooling Instruments for Monitoring Accident Conditions
IX-2	Overhead Handling Systems (Cranes)	USI A-36	Control of Heavy Loads Near Spent Fuel Pool
X	Auxiliary Feedwater System	TMI II.E.1.1	Auxiliary Feedwater System Evaluation
XIII-1	Conduct of Operations	TMI I.C.6 TMI III.A.1 TMI III.A.2	Procedures for Verification of Correct Performance of Operating Activities Improve Licensee Emergency Preparedness - Short-Term Improving Licensee Emergency Preparedness - Long-Term
XV-21	Spent Fuel Cask Drop Accidents	USI A-36	Control of Heavy Loads Near Spent Fuel Pool
XV-22	Anticipated Transients Without Scram	USI A-9	Anticipated Transients Without Scram
XV-23	Multiple Tube Failures in Steam Generators	USI A-3, A-4, A-5, USI A-9	Westinghouse, Combustion Engineering, and Babcock and Wilcox Steam Generator Tube Integrity Anticipated Transients Without Scram
XV-24	Loss of All AC Power	USI A-44	Station Blackout

APPENDIX C

PLANT-SPECIFIC SEP TOPICS DELETED, REFERENCE LETTER, AND REASON FOR DELETION

SEP Topic No.	SEP title	Date of letter	Reason for deletion of topic
II-4.E	Dam Integrity	11/16/79	Not applicable to site
III-3.B	Structural and Other Consequences (e.g., Flooding of Safety-Related Equipment in Basements) of Failure of Underdrain Systems	12/26/80	Not applicable to site because site does not have a system whose function is to lower the groundwater table
III-7.A	Inservice Inspection, Including Prestressed Concrete, Containments With Either Grouted or Ungrouted Tendons	5/7/81	Not applicable to this facility's design
III-7.C	Delamination of Prestressed Concrete Containment Structures	11/16/79	Not applicable to this facility's design
III-8.B	Control Rod Drive Mechanism Integrity	9/26/80	Addressed by NUREG-0479, "Report on BWR Control Rod Drive Failures," which fulfills the intent of this topic
III-10.B	Pump Flywheel Integrity	11/16/79	Not applicable - applies to PWR safety topic
III-10.C	Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves	11/16/79	Not applicable to this facility's design
IV-3	BWR Jet Pump Operating Indications	11/16/79	Not applicable to this facility's design
V-1	Compliance With Codes and Standards	11/27/81	Reviewed under inservice inspection/inservice test program
V-2	Applicability of Code Cases	11/16/79	Not applicable at this time; to be reviewed for any future modifications using references to Code Cases
V-7	Reactor Coolant Pump Overspeed	11/16/79	Not applicable - applies to PWR safety topic
V-9	Reactor Core Isolation Cooling System (BWR)	11/16/79	Not applicable to this facility's design
VI-2.C	Ice Condenser Containment	11/16/79	Not applicable to this facility's design
VI-7.A.1	Emergency Core Cooling System Reevaluation To Account for Increased Reactor Vessel Upper-Head Temperature	11/16/79	Not applicable - applies to PWR safety topic
VI-7.A.2	Upper Plenum Injection	11/16/79	Not applicable to this facility's design
VI-7.C.3	Effect of PWR Loop Isolation Valve Closure During a Loss-of-Coolant Accident on Emergency Core Cooling System Performance	11/16/79	Not applicable - applies to PWR safety topic
VI-7.F	Accumulator Isolation Valves Power and Control System Design	11/16/79	Not applicable - applies to PWR safety topic
VI-9	Main Steam Line Isolation Seal System (BWR)	11/16/79	Not applicable to this facility's design
VI-10.B	Shared Engineered Safety Features, Onsite Emergency Power, and Service Systems for Multiple Unit Stations	11/16/79	Not applicable to site
VII-7	Acceptability of Swing Bus Design on BWR-4 Plants	11/16/79	Not applicable to this facility's design
IX-4	Boron Addition System (PWR)	11/16/79	Not applicable - applies to PWR safety topic
XI-1	Appendix I	11/16/79	Being resolved under generic activities A-02, "Appendix I," and B-35, "Confirmation of Appendix I Models." (See "Basis for Deletion" in Appendix A under Topic XI-1.)
XI-2	Radiological (Effluent and Process) Monitoring Systems	11/16/79	Being resolved under generic activities A-02, "Appendix I," and B-67 "Effluent and Process Monitoring Instrumentation." (See "Basis for Deletion" in Appendix A under Topic XI-2.)

SEP Topic No.	SEP title	Date of letter	Reason for deletion of topic
XV-2	Spectrum of Steam System Piping Failures Inside and Outside Containment (PWR)	11/16/79	Not applicable - applies to PWR safety topic
XV-6	Feedwater System Pipe Breaks Inside and Outside Containment (PWR)	11/16/79	Not applicable - applies to PWR safety topic
XV-10	Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant (PWR)	11/16/79	Not applicable - applies to PWR safety topic
XV-12	Spectrum of Rod Ejection Accidents (PWR)	11/16/79	Not applicable - applies to PWR safety topic
XV-17	Radiological Consequences of Steam Generator Tube Failure (PWR)	11/16/79	Not applicable - applies to PWR safety topic
XVI	Technical Specifications	11/5/80	Will be addressed after completion of the integrated assessment

APPENDIX D

PROBABILISTIC RISK ASSESSMENT STUDY

Risk Assessment of Selected Integrated Assessment Issues for
Big Rock Point Nuclear Power Plant

A number of issues being considered for action in the Big Rock Point Integrated Assessment have been evaluated through the use of risk assessment techniques. The issues selected for evaluation were chosen from the original list of Big Rock Point SEP topics as identified in Chapter 4 of the Integrated Assessment, as well as additional TMI and generic issues being considered for action on this plant. These additional issues are identified in Chapter 5 of the Integrated Assessment Report and the Consumers Power Company June 1, 1983 report, "Integrated Assessment of Open Issues and Schedule for Issue Resolution". Due to the very limited time available for the staff to perform their evaluation, only a limited number of issues could be considered. Issues chosen were those which were amenable to the risk assessment methodology previously developed for the SEP program. This methodology was modified to provide issue specific averted doses as described in the addendum to Attachment 1, and also discussed in Section 2 of Attachment 2.

In addition to the issues originally included in the integrated assessment program, the staff has also evaluated a number of issues which developed from our evaluation of the utility performed Big Rock Point Probabilistic Risk Assessment. These issues were subjected to the same evaluation as the other integrated assessment issues. The potential benefit from resolution of the problems identified from the PRA review, are presented in this appendix to allow for review of the relative benefits from their resolution in relationship to other proposed actions to arise from the SEP program.

Issues evaluated by the staff and their source are identified below:

TABLE 1

Issues Evaluated for the BRP Integrated Assessment

SEP Topics (Analysis found in Attachment 1)

III-5.B	Pipe Break Outside Containment
III-8.A	Loose Parts Monitoring
III-10.A	Thermal Overload Protection

V-5	RCPB Leak Detection
V-10.A	Residual Heat Removal System Heat Exchanger Tube Failure
V-11.A	Isolation of High and Low Pressure Systems
V-11.B	RHR Interlock Requirements (Systems and Electrical)
VI-4	Containment Isolation System
VI-10.A	Response Time Testing
VII-1.A	RPS Isolation
VII-3	Safe Shutdown Systems
VIII-3.B	DC Bus Voltage Monitoring
VIII-4	Electrical Penetrations of Reactor Containment
IX-3	Service and Cooling Water Systems
IX-5	Ventilation Systems
XV-8	Control Rod Misoperation
XV-18	Radiological Consequences of MSL Failure Outside Containment

Additional TMI and Generic Open Issues from the Utility's June 1st Report. (Analysis found in Attachment 2)

7	Scram Dump Tank Level Instrumentation-Generic Letter 81-18
8	Single Channel Reset
11	Turbine Bypass Valve EHC System
17	PCS Isolation
44	BS&B Valve Data
50E	Containment Airlock

63	Containment Purging
73	Control of Heavy Loads
74	Reactor Coolant System Vents (NUREG-0737)
75B	Fire Protection RDS Radiant Energy Shield
75C	Fire Protection-Associated Circuits Appendix B
81	PORV Position Indication (NUREG-0737)

Additional issues developed from staff review of Utility PRA (Analysis found in Attachment 3). TMI (NUREG-0737) action items identified.

Secondary System Instabilities

RDS Reliability-High Pressure Recycle

Hydrogen Monitoring (NUREG-0737)

ICC Instrumentation (NUREG-0737)

Recirculation Pump Trip

Plant Shielding (NUREG-0737)

Control Room Habitability (NUREG-0737)

Appendix R-Alternate Shutdown System

Emergency Condenser Makeup

Post-Incident System Reliability

Early Enclosure Spray

Since a plant specific PRA was available for Big Rock Point, it was possible to obtain a quantitative assessment of the risk significance for resolution of the above issues. The methodology adopted for this study was to examine the impact of each issue on the systems it affects and to assess the risk reduction potential on the issue by quantitative consideration of the fault trees and event trees of the Big Rock Point PRA. For each issue, consideration was taken of the impact that issue resolution would have on the calculation of a component or system unavailability in the Big Rock Point fault trees. Once this system impact had been determined, the change in the core melt frequency due to the resolution of the issue was calculated. This involves the recalculation of the frequency of the dominant accident sequences that contained the affected systems. Utilizing this change in core melt frequency it was then possible to determine changes in expected population exposure due to resolution of the issues. Details of this methodology is found in Section II of Attachment 2 for the integrated assessment issues, and Attachment 3 for the PRA derived issues.

The Big Rock PRA was used as a baseline model for this analysis. Modifications recently undertaken and not reflected in the PRA, or changes being contemplated as result of the PRA are not considered in this study. However, it should be noted that a low containment isolation reliability is a major contributor to the plant risk. Some work has been performed to increase the reliability of containment isolation. While it is not yet possible to quantify the amount of improvement, it does appear that these modifications have resulted in a more reliabile containment isolation capability. This would result in somewhat lower averted risk values than shown in this analysis. At most these reductions would not be expected to exceed a factor of 2 or 3 for selected issues.

Presenting the impact of issue resolution as expected averted dose (person-rem per year) provides a useful indication of the risk reduction potential inherent in each issue. This quantity represents how much public radiological exposure could be reduced from current expected values, expressed on a per year basis. The issues evaluated provided risk reductions from nil upwards to approximately 200 person-rem per year. It should be noted that the person-rem reduction calculated for some issues does not necessarily indicate the actual person-rem reduction achievable. This is largely due to the lack of detailed information available to the staff and uncertainty on what hardware modifications are under consideration, or could be the possible result of further study. For these issues, areas of potential concern are identified and the analysis assumptions are presented as a bounding case. Further information from Consumers Power may result in modifications to these results.

It should also be noted that analyses of this nature involve considerable uncertainties. Risk reduction as expressed in person-rem provides a useful indication of the preceived benefit from resolution of the issues presented in this report. However, the risk reduction assessment should be one of several decision tools utilized to arrive at recommended actions on Big Rock Point.

The results of our analysis are summarized below:

TABLE 2

Analysis Results

Issues Developed from Staff Review of
Big Rock Probabilistic Risk Assessment

ISSUE #	Title	Risk Reduction+ (person-rem/RY)
	Alternate Shutdown Panel	228
	Early Enclosure Spray	91
	Emergency Condenser Makeup	67
	Plant Shielding (NUREG-0737)	63
	Post Incident System Reliability	24
	Secondary System Instabilities	22
	RDS Reliability High Pressure Recycle	6
	Recirculation Pump Trip	4

SEP and Generic Issues

ISSUE #	Title	Risk Reduction+ (person-rem/RY)
IX-5	Ventilation Systems	++
63	Containment Purging	210*
75C	Fire Protection-Emergency condenser valve circuits	204
VII-1A	RPS Isolation	201
44	BS&B Valve Data	85*

(++) Not quantified, but believed to be high.
(*) Indicates bounding analysis, reduction potential may be overstated.
(+) These values do not consider potential improvements in containment isolation which would decrease the potential impact of the issue resolution.

Table 2 cont'd.

III-10.A	Thermal Overload Protection	28
11	Turbine Bypass Valve EHC System	26*
17	PCS Isolation	21
75B	Fire Protection RDS Radiant energy shield	7
8	Single Channel Reset	6
74	Reactor Coolant System Vents	5*
7	Scram Dump Tank Level Instrumentatin	4
VIII-3.B	DC Bus Voltage Monitoring	1.9
All remaining issues		Negligible Reduction

Due to the uncertainties previously mentioned for this type of analysis, it is difficult to assign a cutoff value to the risk reduction potential which would be deemed worthy of a recommendation for action. However, one commonly used criteria is to recommend expenditures of $1000 per man-rem of societal dose reduction. It can be seen from the above results that applying this criteria would suggest that some of the issues are indeed beneficial areas for action. Twenty issues show measurable reduction potentials, ranging from a high of 228 person-ream/RY down to approximately at 2 person-rem/RY reduction while 13 issues show a benefit of 20 person-rem/RY or greater. In the course of the integrated assessment, the potential benefit from these issues should be weighted against their implementation cost to assure that available resources are being applied in the areas where they offer the greatest risk reduction to the public. All the issue which show a risk reduction potential of greater than 1.0 person-rem per year are discussed below in decreasing order of impact. For additional information on the analyses for each of these issues and analyses for those issues which were determined to have neglible risk reduction potential, see Attachments 1,2 and 3 to this report.

IX-5 Ventilation Systems

This topic addresses the need for providing further analysis to determine the need of an active ventilation system to assure the operability of equipment needed to shutdown and cool the plant. Since equipment heat loads and cooling requirements, as well as hydrogen build up, were not available, it was not possible to perform a analysis to determine the sensitivity of the plant to ventilation system failures. For the Big Rock Point plant three ventilation systems are of concern: the electrical equipment room ventilation, the Reactor Depressurization

System (RDS) battery area ventilation, and the diesel-generator room ventilation. The RDS battery area and the electrical equipment room both have ventilation systems that are not powered from an emergency bus. During a loss of offsite power, if the ventilation systems are required to prevent equipment failures in these areas, no further faults are required to fail the equipment in these areas. Failure of the equipment during a loss of offsite power could lead to a core melt with a frequency larger than that calculated in the Big Rock Point PRA. However, due to insufficient information from the licensee, it was not possible to quantify the actual risk significance. It is believed that ventilation in these areas is important and a detailed look should be taken at equipment heat loads and ventilation requirements. Ventilation induced failures were not found to be a significant event for the diesel generator room.

75A Alternate Shutdown System

This issue concerns the ability to safety shut down the reactor during conditions of fire in either the control room, the electrical equipment room, the exterior cable penetration room, or the containment electrical penetration area. It is proposed that this capability be improved through the use of an alternate shutdown system, situated in areas isolated from the fire affected locations described above. This alternate shutdown system will allow for the monitoring and control of the primary coolant system in the event of a fire. This modification essentially removes the impact of all fire initiated core melt sequences. Installation of this system was estimated to result in a risk reduction of 228 person-rem per year. Improved containment isolation has no impact on this result.

75C Fire Protection-Emergency Condenser Valve Circuits

This issue deals with the frequency of fires in three vital plant areas and the consequences of these fires. The three areas are the electrical equipment room, the penetration area outside containment and the penetration area inside containment. An unsuppressed fire in any one of these areas could lead directly to a core melt, a result that is confirmed in the Big Rock Point PRA. Fires in these areas can disable the emergency condenser RDS/core spray system, and the power conversion system. The proposed modification is to reroute the emergency condenser cables in this area so that a fire in a single location could not disable all systems required to shut down the plant. The core melt frequency from these fire sequences was evaluated both before and after the proposed modification. The reduction in core melt frequency produced a reduction of 204 person-rem per year in the population exposure, independent of containment isolation upgrade.

VII-1.A Isolation of Reactor Trip System from Non-Safety Systems.

The isolation of all safety systems from non-safety systems is required under the current licensing criteria. Isolation devices should prevent a failure in a non-safety system from affecting the performance of the safety system. At the Big Rock Point plant suitable isolation is provided between the RPS and its non-safety control systems. However, suitable isolation may not exist between the RPS channels and their respective power supplies. If the protection devices in place are inadequate, the assumption used in the analysis, then an off normal output from either of the motor generator sets could fail the RPS. This situation was analyzed and found to lead to a failure to scram probability of approximately 2.2E-4. This dominated the failure to scram sequence frequency. Resolution of this issue would involve the installation of suitable isolation between the RPS and their power supplies. Assuming the present isolation is inadequate, this resolution is calculated to result in a risk reduction in public exposure of 201 person-rem per year and is independent of whether the containment isolation capability is improved.

63 Containment Purging

The containment vents at the Big Rock Point plant are normally open. In the event of an accident these vent valves are required to close. Failure of these valves to close was one of the dominant contributors to the containment leakage probability in the Big Rock PRA. The concern addressed by this issue is that in the event of a LOCA or transient that results in containment pressurization, debris inside the containment could be transmitted to the vent system ductwork and prevent vent valve closure. The proposed resolution is to install debris screens over the vent ducts to prevent debris accumulation around the valves. Also evaluated as part of this issue was the benefit that could be gained through limited purging of the containment (currently the Big Rock Point containment is continuously purged) and increased testing of the vent valves.

The analysis performed was a sensitivity analysis since the exact relationship between debris accumulation and vent valve failure is not known. The failure probability used in the Big Rock Point PRA for vent valve failure was increased by 1, 50, and 100 percent to determine what potential consequences due to debris induced vent valve failures could be obtained. For the 100 percent increase in the vent valve failure probability, the population exposure changed by approximately 111 person-rem per year. This result indicates that if debris blockage of purge valves is possible, some corrective action can provide a reasonable reduction in public exposure.

Decreasing the test interval for the vent valves from 18 months to 6 months will yield a population exposure reduction of 75 person-rem per year. Limited purging, if possible, will result in an 81 person-rem per year reduction in the population exposure if purging is limited to 90 hours per year. The use of increased testing and limited purging together results in a 99 person-rem per year reduction in the population exposure. Taken with the installation of purge valve debris screens, the total risk reduction potential for this issue is 210 person-rem per year.

Early Enclosure Spray

The containment spray system at Big Rock Point operated with a 15 minute delay upon detection of high containment pressure. This delay actuation of the sprays could result in degradation of equipment used to mitigate the accident, due to excessive temperatures. The proposed modification (which has been completed) is to eliminate the 15 minute time delay so that the enclosure spray can promptly activate when enclosure pressure reaches 2.2 psig following a release from the primary system. This modification is expected to result in a reduction in risk of 91 person-rem/per year, if the containment isolation is not upgraded.

44 BS&B Valve Data

There have been some preliminary indications that the normal air pressure provided to air operated valves throughout the plant may not be sufficient to stroke the valves. If this is the case, air operated valves may not move to the positions demanded of them or maintain that position. There is some doubt concerning this issue. If air supplies are sufficient, this issue is of no importance to risk. If, however, there is an air pressure problem, the following systems important to safety would be affected: main condenser system, feedwater system, condensate system, control rod drive system, demineralized water system, liquid poison system, primary system isolation, vent valves and containment isolation. The analysis showed that the air operated valve failures significantly affected the failure probability of two systems, the demineralized water system and the main condenser. All other systems were not significantly affected because (1) the valves failed in the proper safety position, (2) valve failures did not significantly affect system failure probabilities, or (3) the change in the system failure probability did not significantly affect the dominant accident sequences. For the two systems found to be impacted, air operated valve failures contributed 77 person-rem per year and 8 person-rem per year to the population exposure due to induced failures of the demineralized water system and main condenser respectively, assuming containment isolation is not upgraded. Action in this area could therefore provide a meaningful risk reduction IF air pressure is currently determined to be insufficient for full stroking of air operated valves.

Emergency Condenser Makeup

Upon loss of the power conversion system, energy from decay heat in the primary system must be removed through use of the emergency condenser, while the plant remains at pressure. Makeup water to the shell side of the emergency condenser must be provided within four hours, or its inventory will be depleted and core cooling lost. It is proposed that the reliability of the emergency condenser be improved through converting a manual makeup valve into an automatic valve which allows the use of the fire water system for condenser makeup. This modification is expected to result in a reduction in risk of 67 person-rem/per year, assuming containment isolation is not upgraded.

54 Plant Shielding (NUREG 0737)

This issue concerns the resultant exposure to plant personnel required to mitigate the effects of core damage and to obtain necessary air samples following a reactor accident. It is felt that current plant shielding would, following a postulated core melt accident, result in radiation levels which would hamper or preclude repair of long term cooling systems. This lack of repair capability could then reduce the operating staff's ability to mitigate core melt accidents. Improved plant shielding was estimated to result in a reduced population exposure of 63 person-rem per year, if the containment isolation capability is not upgraded.

III-10.A Thermal Overload Protection

Current criteria require that the thermal overload protection for motors of motor-operated valves be bypassed during emergency operation or the trip set point should be set high enough to prevent spurious operation of the thermal overload protection. Additionally, for valves that use a torque switch rather than a limit switch to end valve travel, the torque switch should be bypassed with a limit switch during automatic actuation. At the Big Rock plant all the criteria are not met. The thermal overload trip setpoints are not periodically tested. This issue affects the AC powered valves in the shutdown cooling system, the fire protection system, recirculation line isolation system, the post incident system, condensate system, and the emergency condenser system. DC powered valves at Big Rock Point do not have thermal overload protection and therefore are not affected.

The analysis performed evaluated the effect of setpoint drift of the thermal overload protection. It was assumed that any out of calibration failures of the thermal overload protection would prevent valve operation. This valve failure mode was incorporated into the system fault trees for each system listed above. The thermal overload protection failure had little or no effect on the post incident system, recirculation line isolation system, and the emergency condenser system failure probabilities. The failure of the thermal overload protection did affect the failure probabilities of the remaining three systems. The major effect was the change in the failure probabilities of the shutdown cooling and fire protection systems due to thermal overload protection spurious failures. This resulted in slightly more than a 10 percent increase in core melt frequency, and resolution of this issue was determined to result in a risk reduction of 28 person-rem per year, assuming containment isolation is not upgraded.

11 Turbine Bypass Valve EHC System

The turbine bypass valve electrohydraulic control (EHC) system, also known as the Rucker System, at Big Rock Point has shown a tendency to spuriously open or fail to open the turbine bypass valve. These control system induced instabilities have convinced plant staff to reevaluate the relative effectiveness of the EHC system and to consider possible corrective actions. It was not known what improvement in EHC system reliability was likely from reevaluation. Therefore a sensitivity analysis was performed to provide some insight into the potential risk reduction possible through improved reliability of the EHC turbine bypass valve system . Assuming that an order of magnitude reduction in the failure-to-open probability and spurious opening probability is obtained, a 26 man-rem per year reduction in population exposure can be obtained. A smaller increase in EHC reliability (factor of 2) would result in a correspondingly smaller risk reduction potential of 14 person-rem per year. These values assume that containment isolation capability is not upgraded.

Post Incident System Reliability

This modification calls for the installation of locks on manual valves in the post incident systems so that the valves can only be locked in correct positions. This is to avoid human error of placing valves in wrong positions after testing or maintenance. This modification is expected to result in a reduction in risk of 24 person-rem/per year, assuming containment isolation is not upgraded.

16 Secondary System Instabilities

This issue involves the present behavior of the plant condensate system. Following a load rejection, the primary coolant system will blow down through the turbine bypass valve to the condenser hot well (assuming proper operation of the EHC system). As a result, the hot well levels will swell causing a signal to open the reject valve. When the reject valve opens, a significant portion of the condensate pump discharge is diverted from the suction of the reactor feed pumps to the condensate storage tank. The loss of feed pump suction results in a feed pump trip and, thus, the loss of primary system makeup during the blowdown. The loss of primary inventory could result in a low reactor water level condition which results in a reactor trip.

The proposed resolution of this issue is to modify the existing reject valve control circuitry such that valve opening does not occur during load rejection. This will reduce plant trips as initiating transients and will reduce core melt frequency. The staff's analysis indicates that resolution of this issue can result in a risk reduction of 22 person-rem per year, assuming containment isolation capability is not upgraded.

17 PCS Isolation

Currently there are eight primary coolant system vent and drain lines that have only a single manual valve for isolation of the primary coolant system from the containment atmosphere. Failure, a severe rupture, of any one of these valves would result in a small interfacing system LOCA. The valve failures are expected to occur with a frequency of 1.9E-3/yr using data from the Big Rock Point PRA, with a resultant core melt frequency of 8.9E-5/yr. The proposed modification, the addition of a second manual valve or pipe caps, would effectively eliminate the contribution to the interfacing system LOCA frequency due to leakage through these vent and drain lines. This action results in a reduction in the population exposure of 21 person-rem per year, assuming containment isolation capability is not upgraded.

75B Fire Protection - RDS Radiant Energy Shield

This issue deals with the possibility of a fire disabling the RDS/core spray system, the emergency condenser and inducing a loss of offsite power. The three potential fire areas are: the core spray pump room, the south face of the steam drum wall, and the area where the emergency condenser is located. A simplified model was constructed to represent the possibility of a fire in one of these three areas that would ultimately causes a loss of offsite power. (The licensee claims that it is not possible for a fire in these areas to result in a loss of offsite power.) Under the assumptions utilized for this analysis, the fires postulated in the above areas contributed to the plant risk only slightly. The proposed modifications, fire shields between the RDS/core spray system and the emergency condenser system, resulted in a 7 person-rem per year reduction in the population exposure, assuming containment isolation capability is not upgraded.

8 Single Channel Reset

There have been ocassions when the reactor protection system has been reset, a primary coolant to containment leakage path has resulted from the failure of the scram valves and the scram dupm tank (SDT) vent and drain valves to open and close in the proper sequence. These events did not occur during power operation, but if a similar event had occured at operating pressure, a small LOCA would result. The operating data was used to develop a small LOCA initiating frequency for this type of LOCA. This frequency was then used in the dominany small LOCA accident sequences from the Big Rock Point PRA. After the core melt frequency due tothis small LOCA was calculated based on the proposed modification, installation of redundant MOVs on the SDT vent and drain lines. The core melt frequency resulting from this reduced LOCA initiator was then calculated. The modification resulted in a risk reduction of 6 person-rem/per year, if the containment isolation is not upgraded.

RDS Reliability-High Pressure Recycle

Currently Big Rock Point has a limited ability of inject high pressure coolant for primary system inventory makeup following a small LOCA or other transitnt when makeup is necessary. Without a high pressure source of makeup, a high reliance is placed upon the reactor depressurization system (RDS) which is utilized to reduce reactor pressure and allow makeup through low pressure systems. The modification proposed is to provide high pressure makeup to the primary system but routing containment water due to releases from the primary system back to the RCS via feedwater/condensate systems. This avoids the need to rely solely on the RDS system. This modification was calculated to provide a risk reduction potential of 6 person-rem/per year, if the containment isolation capability is not upgraded.

74 Reactor Coolant System Vents (NUREG-0737)

This issue deals with the ability to vent the primary coolant system to hydrogen which can accumulate during a core damage accident. Currently at the Big Rock Point Plant the primary system ven is installed. However it is not seismically qualified, no procedures exist for its use and there are not provisions for test connects.

Upgrading the vent system to an operational condition would be of benefit in situations where high reactor pressure is maintained and the high pressure heat removal capabilities have been lost. This combination of events would lead to hydrogen generation. The analysis conservatively evaluated the combination of initiators, transients and LOCA's and system failures necessary to produce the combination of conditions outlined above. A containment probability of 1 was conservatively used to calculate a populational exposure since accident sequences with hydrogen generation were not part of dominant sequences in the Big Rock Point PRA. A reduction in the population exposure of less than 5 person-rem/per year results from the use of this primary system vent, assuming containment isolation is not upgraded.

7 Scram Dump Tank Level Instrumentation

In the NRC generic letter 81-18, dated March 30, 1981, the staff indicated that common-cause failures may be the most significant contributors to the unreliability of the scram capabilities of BWRs. As a result of this position diverse scram discharge volume (SDV) level instrumentation is required for BWR plants. The analysis performed evaluated the contribution to the reactor protection system (RPS) failure probability related to common-cause SDV level instrumentation failures. A simplified system fault tree was constructed and quantified twice, once with no congrivugion from this cause considered. The second quantification represents the RPS with an effective alternative to the non-redundant SDV level instrumentation. With a modification to the level instrumentation to remove the common cause failure effects, a reduction in public risk of 4 person-rem/per year can be realized, if the containment isolation capability is not upgraded.

Recirculation Pump Trip

The consideration of actions to reduce the risk from ATWS events has been an ongoing effort for the staff. For boiling water reactors, an effective modification to reduce the severity of a postulated ATWS event, has been for the installation of an automatic trip of the reactor recirculation pumps. Upon a high pressure signal, trip of these pumps will result in a decreased reactor power level and moderation of event severity. For Big Rock Point, the installation of recirculation pump trip was shown to result in a risk reduction potential of 4 person-rem/per year, whether or not the containment isolation capability is upgraded.

VIII-3.B DC Bus Voltage Monitoring

Current licensing criteria require that sufficient instrumentation be provided in the control room so that the operator can prevent the loss of a DC buss. The DC power status indication currently not available at Big Rock Point included: DC bus voltage, battery current, battery charger and breaker status. The analysis performed showed that the additional instrumentation would result in a small but measurable increase in the reliability of DC power systems for Big Rock Point. Upgrading the DC instrumentation was calculated to provide a risk reduction potential of less than 2 person-rem/per year, if the containment isolation capability is not upgraded.

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RISK BASED CATEGORIZATION OF BIG ROCK POINT SEP ISSUES

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EXECUTIVE SUMMARY

This is an Executive Summary of the report, "Risk-Based Categorization of Big Rock Point SEP Issues." Refer to the main report for the details of the analysis we have used to classify the Big Rock Point SEP issues with respect to their importances to risk. These classifications have been performed using probabilistic risk assessment (PRA) techniques.

The issues have been examined from the perspective of the impact their resolution would have on risk from the plant. The classifications are based on the criteria given in Table Ex-1. Following are discussions of each issue, their classifications based on these criteria, and the supportive results of our analysis which were judged by these criteria.

A plant specific PRA, performed by the utility and currently under NRC review, was available for the Big Rock Point plant. This PRA was used in the analyses performed here as representative of the plant as it is now. The methodology adopted in this study was to examine the impact of each issue on the systems they affect and assess the importance of the issue by quantitative consideration of the fault trees and event trees in the Big Rock Point PRA. For each issue, we estimated the impact its resolution would have on the Big Rock Point PRA fault trees. The effect of an issue on risk at the Big Rock Point plant was determined by evaluating the effect that the fault tree changes would have on the event trees developed in the Big Rock Point PRA. The changes in the frequency of dominant accident sequences represents the effect resolution of each issue would have on the expected core melt frequency of the Big Rock Point plant. The magnitude of the core melt frequency change was the basis for the ranking of an issue (high, medium, or low) with regards to risk significance.

Table Ex-2 gives the results of the classification of the issues as high, medium, or low importance to risk. The numbers denote the issues.

The rest of this executive summary consists of brief summaries of each of the issues evaluated and it's risk resolution. The main report contains more detailed discussions of the methodology and the analysis of each issue.

TABLE EX-1

Classification of Issues

Classification	Criterion
High	Resolution of issue would have a dominant impact on the value of the Big Rock Point core melt frequency.
Medium	Resolution of issue significantly impacts the value of the Big Rock Point core melt frequency.
Low	Resolution of issues has virtually no impact on the value of the Big Rock Point core melt frequency.

TABLE EX-2

Classification of Issues Importance to Risk

<u>High</u>

IX-5	Ventilation Systems

<u>Medium</u>

III-10.A	Thermal Overload Protection
VII-1.A	RPS Isolation

<u>Low</u>

III-5.B	Pipe Break Outside Containment
III-8.A	Loose Parts Monitoring
V-5	RCPB Leak Detection
V-10.A	Residual Heat Removal System Heat Exchanger Tube Failure
V-11.A	Isolation of High and Low Pressure Systems
V-11.B	RHR Interlock Requirements (Systems and Electrical)
VI-4	Containment Isolation System
VI-10.A	Response Time Testing
VII-3	Safe Shutdown Systems
VIII-3.B	DC Bus Voltage Monitoring
VIII-4	Electrical Penetrations of Reactor Containment
IX-3	Service and Cooling Water Systems
XV-8	Control Rod Misoperation
XV-18	Radiological Consequences of Main Steam Line Failure Outside Containment

III-5.B Pipe Break Outside Containment
IX-3 Station Service and Cooling Water System

These two issues deal with passive pipe failures that could affect the operability of the fire protection system and therefore the RDS/CS system. Topic IX-3 deals with passive failures of non-redundant pipe segments in the fire protection system itself. Topic III-5.B concerns ruptures of piping in the intake structure that could affect the operation of the fire protection system. The analysis performed evaluated the contribution of piping failures in the fire protection system and the systems in the intake structure to the failure probability of the fire protection system. The failure probability of the fire protection system is dominated by the failure of the fire protection system pumps due to mechanical pump failures. The contribution of pipe failures was several orders of magnitude smaller than the contribution of the pump failures. Eliminating the piping failures that could affect the fire protection system would have virtually no effect on the fire protection system failure probability. We therefore rank this issue to be of low risk significance.

III-8.A Loose Parts Monitoring and Core Barrel Vibration Monitoring

The Big Rock Point plant does not have a loose parts monitoring system (for loose parts within the reactor coolant pressure boundary) to meet the requirements of Regulatory Guide 1.133. Features lacking for the system would include sensors on the exterior surface of the RCPB capable of detecting acoustic disturbances, system sensitivity specifications, alert levels, data acquisition modes and other system and procedural requirements.

The loose parts that would be detected by a loose parts monitoring system have not been a significant cause of transients at nuclear power plants. Due to the relatively high transient frequency from other causes the elimination of loose parts induced transients has a small effect on the core melt frequency. This issue is of low risk significance.

III-10.A Thermal Overload Protection for Motors of Motor-Operated Valves

Current criteria require that the thermal overload protection for motors of motor operated valves be bypassed during emergency operation or the trip set point should be set high enough to prevent spurious operation of the thermal overload protection. Additionally, for valves that use a torque switch rather than a limit switch to end valve travel, the torque switch should be bypassed with a limit switch during automatic actuation. At the Big Rock Point plant all the criteria are not met. The thermal overload trip setpoints are not periodically tested. This issue affects the AC powered valves in the shutdown cooling system, the fire protection system, recirculation line isolation system, the post incident system, condensate system and the emergency condenser system. DC powered valves at Big Rock Point do not have thermal overload protction and are therefore unaffected.

The analysis performed evaluated the effect of setpoint drift of the thermal overload protection. It was assumed that any out of calibration failures of the thermal overload protection would prevent valve operation.

This valve failure mode was incorporated into the system fault trees (from the Big Rock Point PRA) for each system listed above. The thermal overload protection failure had little or no effect on the post incident system, recirculation line isolation system and the emergency condenser system failure probabilities. The failure of the thermal overload protection did affect the failure probabilities of the remaining three systems. The change in the condensate system failure probability had virtually no effect on the expected core melt frequency. However, the change in the failure probabilities of the shutdown cooling and fire protection systems due to thermal overload protection spurious failures contributed slightly more than an additional 10% to the core melt frequency. We therefore rate this issue to be of medium risk significance.

V-5 Reactor Coolant Pressure Boundary Leakage Detection

The current NRC regulatory guides recommend installation of at least three seismically qualified leakage detection systems of a specified type with the sensitivity to detect a one gallon per minute leak from the reactor coolant pressure boundary in one hour. At the Big Rock Point plant all three required systems are available. According to the utility, two of the systems appear to meet the NRC sensitivity requirements. (At this time the utility's evaluation of the detection system's sensitivity has not been fully reviewed by the NRC.) The third system, sump level monitoring, has the capability to detect a 1 gpm leak but the level is checked only every 8 hours.

This issue was analyzed by evaluating the probability that a small leak will go undetected and grow to LOCA proportions. (This evaluation did not consider the significance of leakage detection to mitigate high energy pipe breaks. It also did not consider common mode pipe break effects, e.g., pipe whip.) The difference between the NRC regulatory guide recommendation and the conditions at Big Rock Point is the adequacy of one of three detection systems. The analysis evaluated the benefit gained by improving the sensitivity of this third leakage detection system. A third detection system would decrease the probability of not detecting a leak before it could grow to LOCA proportions. Although there is a pipe break LOCA frequency reduction, assuming three detection systems instead of two, the pipe break LOCA frequency is reduced sufficiently with only two detection systems so as not to contribute significantly to the Big Rock Point core melt frequency. (The lack of seismic qualification does not appear to be significant.) We therefore rank this issue to be of low risk significance.

V-10.A RHR Heat Exchanger Tube Failure

Current NRC criteria require monitoring of reactor primary coolant purity. Also required is monitoring of potential leak paths to the environment from the primary system. At the Big Rock Point plant the monitoring of the primary coolant for possible inleakage from the reactor cooling water system does not meet current criteria. The monitoring of possible leak paths through the reactor coolant water system and the service water system does not meet the current criteria.

The analysis performed evaluated the expected frequency of the combination of heat exchanger failures required to allow for leakage either from the environment to the primary coolant or from the primary system to the environment. (This analysis did not consider long term effects of impurities in the primary system.) The frequency of multiple heat exchanger failures is low enough, on the order of E-7/yr, that monitoring systems beyond what is currently employed at Big Rock Point (twice weekly sampling during system operation) would not significantly affect the risks associated with the operation of this plant. (Additionally, the consequences of this combination of events are less severe than those of core melt accidents which have a higher frequency than the combination of heat exchanger failures.) We therefore rate this issue to be of low risk significance.

V-11.A Requirements for Isolation of High and Low Pressure Systems
V-11.B RHR Interlock Requirements

Current NRC criteria require that the interfaces between high and low pressure systems have diverse and independent interlocks to prevent inadvertent overpressurization of the low pressure system. At the Big Rock Point plant the interlocks for two systems do not meet the current criteria. Each pair of the shutdown cooling system isolation valves is controlled by a single interlock. The core spray system has a single check valve and two normally closed injection valves for each injection line. There are no interlocks on the core spray MOVs.

The interlocks for the shutdown cooling system (SDCS) have been deemed as an acceptable deviation from the current criteria. (Although the SDCS isolation valves do not have diverse and independent interlocks the interlock signal is produced by redundant pressure switches and redundant relays. Additionally, the interlock is adequately protected from potential common cause electrical faults. For these reasons the interlocks for the SDCS are acceptable.) The overpressure protection for the core spray system was analyzed. The core spray valves are cycled monthly and at the time of the test the check valves, one on each of the two injection lines, are checked for back leakage. The monthly tests are also the time at which both core spray system isolation valves on an injection line are most likely to be inadvertently opened while the primary system is pressurized. The analysis considered the possibility of both valves being open and the failure of the check valve. The frequency of an interfacing system LOCA in this case was on the order of E-6/yr which is small in comparison to the expected core melt frequency at the Big Rock Point plant. We therefore rank this issue to be of low risk significance.

VI-4 Containment Isolation System

Nine of the containment penetrations at the Big Rock Point plant do not conform to the current general design criteria (GDC). Among these penetrations there are five configurations which deviate from the GDC. These are

- a normally open manual valve is used outside containment when an automatic MOV is required.

- no isolation valve is used where a remote manual MOV is required,

- check operated valves are used outside containment when an automatic MOV is required,

- no isolation valves are used (for a system closed outside the containment) when manually operated MOVs are required inside and outside containment, and

- no isolation valves are used (for a system closed inside the containment) when an automatic MOV is required outside containment.

The containment leakage probability due to failure of any of the nine penetrations to isolate, in their present configuration, is approximately 1.4E-4. The containment leakage probability calculated for the Big Rock Point PRA was on the order of 0.1. Reducing the contribution of the failure to isolate these nine penetrations to the containment leakage probability would have virtually no effect on the containment leakage probability. We therefore rate this issue to be of low risk significance.

VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response Time Testing

The Big Rock Point Technical Specifications do not require response time testing of the RPS and ESF system, particularly the neutron monitoring channels. Procedures exist at the plant for the calibration of the initiation channels for the RPS, emergency condenser and containment isolation system; however, the Technical Specifications do not include these calibration procedures. Current criteria require that response time testing and the calibration procedures be incorporated into the plant Technical Specifications.

The required functional tests, or their equivalent, are performed at Big Rock Point. With regard to a PRA the response time tests required by current criteria would not add any significant information about the RPS and ESF system beyond that which the functional tests already provide. Incorporation of response time testing would have little or no effect on the results of a PRA. The formalization of the calibration procedures, already in use at the plant, in the plant Technical Specifications would not affect the results of a PRA either. In the PRA the plant conditions are modeled and in this case the requirements of the plant procedures are more restrictive than the plant Technical Specifications. We therefore rank this issue to be of low risk significance.

VII-1.A Isolation of Reactor Trip System from Non-Safety Systems, Including Qualification of Isolation Devices

The isolation of all safety systems from non-safety systems is required under the current licensing criteria. Isolation devices should prevent a failure in a non-safety system from affecting the performance of the safety system. At the Big Rock Point plant suitable isolation is provided between the RPS and its non-safety control systems (including the control room instrumentation). However, suitable isolation may not exist between the RPS

Channels and their respective power supplies. If the protection devices in place are inadequate, the assumption used in the analysis, then an off normal output from either of the motor generator sets could fail the RPS. This situation was analyzed and found to lead to a failure to scram probability of approximately 2.2E-4. This dominated the failure to scram probability and had a significant effect on the core melt frequency calculated for the Big Rock Point PRA, contributing approximately 10% to the core melt frequency. We rank this issue to be of medium risk significance.

VII-3 Systems Required for Safe Shutdown

The systems required to bring the Big Rock Point plant from hot shutdown to cold shutdown with only onsite or offsite power available meet current NRC criteria with one exception. Vital indication in the control room, such as reactor pressure temperature and level, are susceptible to single failures. The initial SEP recommendation was to provide independent and redundant indication of the reactor parameters in the control room, and this is the area analyzed in this report. Subsequently this recommendation was deleted.

The analysis performed showed that the dominant contributor to the loss of this instrumentation is a loss of all electrical power to the instrument panel. This involves a loss of offsite power and a failure of the emergency diesel generator, i.e., the emergency AC power system. With this combination of events a second instrument panel would not function, since no source of AC power is available. Therefore, a second instrument panel would not provide the desired redundancy during the event most likely to involve the need for a second source of instrumentation. We therefore rate this issue to be of low risk significance.

VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

Current criteria require that sufficient instrumentation be provided in the control room so that the operator can prevent the loss of a DC bus or take timely corrective action in the event of a loss of a DC bus. The DC power status indication currently not available to the operator at the Big Rock Point plant includes: DC bus voltage, battery current, battery charger current and breaker status (charger and/or battery). The recommendation is that these indications be installed for the 125V DC system, the diesel generator battery system, the diesel fire pump battery system and the uninterruptible power supplies (UPS). The UPS consists of 4 separate battery sources.

The analysis evaluated the effect of improved annunciation on the unavailabilities of each DC power supply. The reduction in the DC power systems' unavailabilities was used to evaluate the effects the improved DC annunciation would have on the availabilities of the systems to which the DC power systems supplied power. For the UPS, the fire pump battery system and the diesel generator battery system, the reduction of the battery system unavailability had little or no effect on the unavailabilities of the systems to which they supply power.

The 125V DC power supply supports several systems. The effect of a reduction in this system's unavailability was calculated by evaluating the core melt sequences where a loss of 125V DC power could affect any of the systems in the sequence. The results showed the reduction of the 125V DC power system unavailability had little effect on the core melt frequency. We therefore rank this issue to be of low risk significance.

VIII-4 Electrical Penetrations of Reactor Containment

Current criteria require that for each electrical penetration protective systems should provide primary and secondary protection devices to prevent a circuit overload and a single failure from impairing containment integrity. At the Big Rock Point plant secondary protection is not provided for all DC and low power AC penetrations.

The analysis performed used a simplified model to represent the circuit overload and primary circuit breaker failure for the DC and low voltage AC penetrations. The resulting containment penetration failure probability, due to the failure of any one penetration, was less than 1E-4. This is significantly less than the containment leakage probability of approximately 0.1. Therefore, reduction of the failure probability of the electrical penetrations would have little effect on the containment leakage probability. We therefore rank this issue to be of low risk significance.

IX-5 Ventilation System

This topic addresses the need to provide further analysis to determine the need for an active ventilation system to assure the operability of equipment needed to shutdown and cool the Big Rock Point plant. A finding that the ventilation system does not affect the failure probabilities of the systems it serves (i.e., the issue is rated low in risk significance) means that no further analysis of the adequacy of the ventilation system is required. This effort is intended only to indicate for which areas (ventilation systems) further analysis of the adequacy of the ventilation system may be required.

For the Big Rock Point plant three ventilation systems are of concern: the electrical equipment room ventilation, the RDS battery area ventilation and the diesel generator room ventilation.

The RDS battery area and the electrical equipment room both have ventilation systems that are not powered from an emergency bus. Failure of these ventilation systems could be a significant contributor to the Big Rock Point dominant accident sequences depending on the degree to which ventilation is required. These ventilation areas are rated to be of high risk significance, further analysis should be performed to determine the ventilation requirements for these areas.

The diesel generator room has a passive ventilation system. The concern is that once the diesel generator has started the heat buildup may fail the electrical panel in this room. An examination of the Big Rock Point PRA revealed that only one dominant accident sequence involved failure of the emergency AC power provided the diesel generator started. A ventilation induced failure of the electrical panel should not significantly affect the expected core melt frequency. We rate this issue to be of low risk significance.

XV-8 Control Rod Misoperation

The probability of a control rod misoperation is relatively low. This type of initiating event does not affect the ability of the Big Rock Point plant to respond to the overpower condition that could result. The systems required to safely shutdown the plant, including the RPS, are not damaged by the control rod misoperation and are therefore available to mitigate the conditions produced by such an initiator. The RPS failure probability combined with the low frequency for this type of event yields a relatively small core melt frequency, significantly smaller than the expected core melt frequency for this plant. We therefore rate this issue as of low risk significance.

XV-18 Radiological Consequences of Main Steam Line Failure Outside Containment

This issue deals with the radiological consequences of a steam line break outside containment during an accident that does not lead to a core melt. Previous PRA studies have shown that the dominant contributors to risk are core melt sequences. The low frequency of this event combined with the relatively small consequences associated with it lead us to rank this issue to be of low risk significance.

I. Introduction

This report will present the analysis and results for the risk-based categorization of issues identified by the USNRC Systematic Evaluation Program (SEP) for the Big Rock Point Nuclear Power Plant.

Section II will discuss the methodology, Section III will present our results for Big Rock Point and Section IV will give the analysis performed for each Big Rock Point SEP issue.

A brief discussion of the analysis and results for each issue is given in the Executive Summary of this report.

II. Methodology for Categorization of Big Rock Point SEP Issues

The United States Nuclear Regulatory Commission (USNRC) Systematic Evaluation Program (SEP) is identifying deviations from current licensing requirements for older nuclear power plants. This project evaluates those issues which are amenable to study by probabilistic risk assessment (PRA) techniques, for the Big Rock Point plant. The result of this evaluation is the categorization of these issues by the impact their resolution would have on risk. This categorization will be used as input to the USNRC decisions on what hardware and procedure changes will be required for the nuclear plants as the product of the SEP.

Not all of the issues identified are easily addressed by well-defined PRA techniques. In particular, issues which address the ability of the power plant to safely deal with events for which the frequency and/or effects on plant systems are unknown are not evaluated in this study. PRA examines accident scenarios for which the initiating event frequencies are relatively well known and probabilities of system failures are estimated by detailed consideration of system configuration, random component failures, and system interactions. Thus the issues evaluated are those which address systems or plant features during normal operation or accident situations of relatively well-known frequency where that system or plant feature may be demanded.

Issues excluded are those dealing with seismic, tornado, or flooding events for which the frequency of a given severity event, or any such event, is not well known. Also excluded are issues dealing with high energy line breaks, where it is not the frequency, but the effects on systems, which is not known. Treating these issues in the framework of PRA would generally be at the edge of the state-of-the-art (since event frequencies, etc., are not well known) and thus our confidence in the risk-based categorization of these isues would be less than for the results of our analysis of those issues which fit well into present PRA considerations.

The Big Rock Point Probabilistic Risk Analysis (PRA), produced by the utility, was used as the baseline for this analysis. Information contained in the Big Rock Point PRA included system descriptions, system fault trees, event trees and the dominant accident sequences for Big Rock Point. This information represented the plant as it is now, prior to any SEP proposed modifications.

The method adopted in this study was to examine the impact of each issue on the systems it affects and assess the importance of the issue by quantitative consideration of the fault trees and the results of the Big Rock Point PRA.

For each issue, we consider the impact its resolution would have on the calculation of system or component unavailability in the Big Rock Point fault trees, or if necessary directly on a sequence frequency. That is, we assess the impact on the top event of each Big Rock Point fault tree (or event in any sequence) of each issue. This sometimes required developing further fault trees to incorporate the effect of each issue. For example, issues which impacted the failure rates of basic events or components required further development since the original fault tree ended at that level.

In general, the evaluation was done in consecutive phases in order to reduce the amount of work as much as possible while still getting the required insights to assure a proper ranking.

<u>Phase I</u> - Evaluate the effect of the SEP issue resolution on the particular event or component it is associated with. That is, determine if there is a frequency/reliability change induced on the event/component by resolving the issue as suggested by the NRC. If there is essentially no effect, no further analysis is required and the risk significance is low. If there is an effect, proceed to Phase II.

<u>Phase II</u> - Evaluate the effect of the frequency/reliability change found in Phase I on the overall reliability of the systems which it impacts. If there is essentially no effect, no further analysis is required and the risk significance is low. If there is an effect, proceed to Phase III.

<u>Phase III</u> - Evaluate the effect of the reliability change found in Phase II on the plant core melt frequency. If there is essentially no effect, the risk significance is low. If there is an effect the risk significance is either medium or high. Although the actual core melt frequency change was calculated, no percent change in the core melt frequency was used as the definitive break point between medium and high risk significance. Rather some qualitative judgment was used in the determination of these two classifications.

To determine the risk significance of each issue the Big Rock Point PRA was used as the baseline model. The information in this model included the expected core melt frequency, the dominant accident sequences and the system fault trees. Where possible the effects of the modifications proposed by the SEP branch were incorporated directly into the system models used in the Big Rock Point PRA. The modifications to the baseline model were one of two types; either the modification reduced the value of an event already modeled or the modification affected an event that had not been specifically modeled. Examples of each type of modification, from the analysis, follow.

1. In Topic VIII-3.B the affected component is the station battery. The battery faults are modeled in the Big Rock Point PRA. The modification, proposed by the SEP branch, reduces the battery failure rate. The modification would result in a reduction of the baseline model core melt frequency.

2. In Topic III-10.A the affected component, MOV thermal overload devices, is not specifically modeled in the Big Rock Point PRA. Therefore, the baseline model actually represents the plant with an effective solution to the deviation from current criteria. The contribution of the cutsets containing the component failure/event to the core melt frequency must be added to the baseline core melt frequency.

In both cases a core melt frequency change was calculated. The percentage change in the core melt frequency was the primary factor used in ranking the risk significance of an issue. However, some subjective considerations were important. The Big Rock Point plant is a small nuclear power plant in a sparsely populated region. The relatively small core inventory and low population density would tend to reduce the consequences of a core melt accident. However, the core melt frequency of the baseline model (the Big Rock Point PRA) is relatively high. These two factors tend to force the importance of changes in the core melt frequency in opposite directions. Therefore, the risk significance ranking of a percentage change in the core melt frequency was a relatively subjective decision. For this reason no particular percentage change in the core melt frequency was used as the cut off point between issues ranked to be of high or medium risk significance.

The overall study methodology is given in flowchart form in Figure 1. The importance of an issue is determined by the impact of resolution of the issue on the Big Rock Point fault trees or events and the dominance or nondominance of accidents containing those faults or events. The impacts are developed from the SEP branch evaluations of the issues and the Big Rock Point fault trees. The "dominance" of the Big Rock Point fault trees and events is determined as previously stated from the results of the Big Rock Point PRA. The resulting classifications are given in Table 1.

A discussion of each issue and its classification is given in the Executive Summary of this report. The next section provides a brief overview of the results of this study.

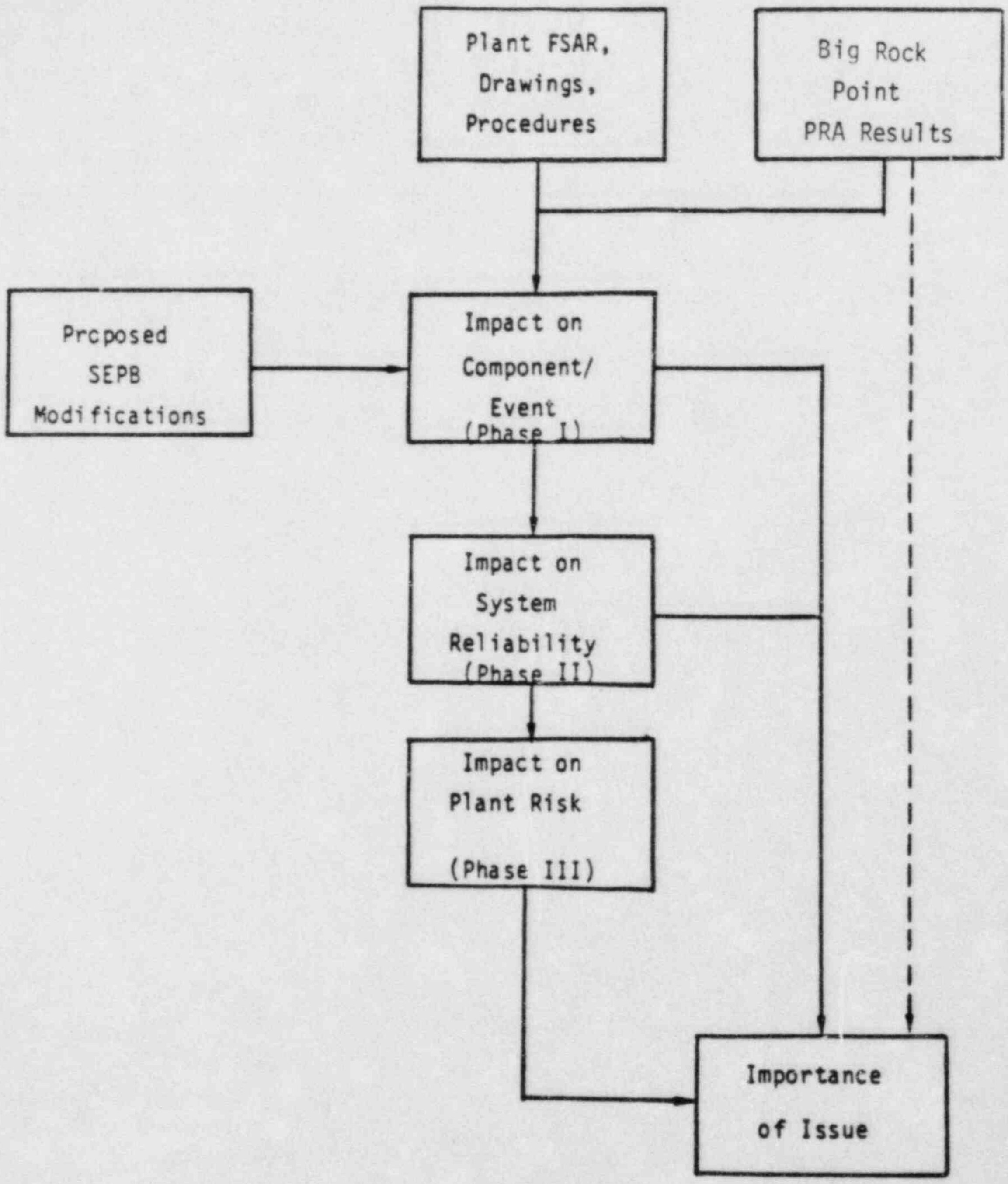


Figure 1. Study Methodology

Table 1

Classification of Issues

Classification	Criterion
High	Resolution of issue would have a dominant impact on the value of the Big Rock Point core melt frequency.
Medium	Resolution of issue significantly impacts the value of the Big Rock Point core melt frequency.
Low	Resolution of issues has virtually no impact on the value of the Big Rock Point core melt frequency.

III. Results

There were 32 issues identified by the Systematic Evaluation Program Branch for the Big Rock Point Nuclear Power Plant. Of these, 15 were outside the scope of our analysis and 17 were within our scope. Table 2 gives those issues we did not analyze and Table 3 gives those issues we did analyze.

Each issue was analyzed for classification by the criteria described in the previous section of this report. That is, we assessed whether resolution of the issue would affect the Big Rock Point fault trees (as presented in the Big Rock Point PRA), and quantified the effect. The fault trees were examined to determine the resulting change in the top event(s), and the Big Rock Point PRA was reviewed to characterize the affected fault trees by whether they would be part of dominant accident sequences.

Table 4 presents the results of our analysis. For each issue, the system or accident event that the issue potentially impacts, the change in unavailability due to resolution of the issue and the component or system for which this was calculated (Phase I), whether the issue affects the top event of the fault tree(s)/event(s), whether the fault tree(s) or event(s) affected would appear in any dominant accident sequences (Phase III), and, based on applying the criteria of Section II to all of the above results, the resulting classification of the issues are given. Table 5 gives a list of the classifications of the issues as high, medium, or low importance to risk. A discussion of the classification of each issue is given in the Executive Summary of this report.

Table 2 SEP Issues Not Evaluated

II-3.B	Flooding Potential and Protection Requirements
II-3.B.1	Capability of Operating Plant to Cope With Design Basis Flooding Conditions
II-3.C	Safety Related Water Supply (UHS)
II-4.B	Proximity of Capable Tectonic Structures in Plant Vicinity
III-1	Classification of Structures, Systems and Components (Seismic and Quality)
III-2	Wind and Tornado Loadings
III-3.A	Effects of High Water Level on Structures
III-3.C	Inservice Inspection of Water-Control Structures
III-4.A	Tornado Missiles
III-4.B	Turbine Missiles
III-5.A	The Effects of Pipe Break on Structures, Systems and Components Inside Containment
III-6	Seismic Design Considerations
III-7.B	Design Codes, Design Criteria, Load Combinations and Reactor Cavity Design Criteria
V-4	Piping and Safe-End Integrity
V-12.A	Water Purity of BWR Primary Coolant

Table 3 SEP Issues Evaluated

III-5.B	Pipe Break Outside Containment
III-8.A	Loose Parts Monitoring and Core Barrel Vibration Monitoring
III-10.A	Thermal-Overload Protection for Motors of Motor-Operated Valves
V-5	Reactor Coolant Pressure Boundary Leakage Detection
V-10.A	RHR Heat Exchanger Tube Failures
V-11.A	Requirements for Isolation of High and Low Pressure Systems
V-11.B	RHR Interlock Requirements
VI-4	Containment Isolation System
VI-10.A	Testing of Reactor Trip System and Engineered Safety Features Including Response Time Testng
VII-1.A	Isolation of Reactor Trip System from Non-Safety Systems, Including Qualification of Isolation Devices
VII-3	Systems Required for Safe Shutdown
VIII-3.B	DC Power System Bus Voltage Monitoring and Annunciation
VIII-4	Electrical Penetrations of Reactor Containment
IX-3	Station Service and Cooling Water Systems
IX-5	Ventilation Systems
XV-8	Control Rod Misoperation
XV-18	Radiological Consequences of Main Steam Line Failure Outside Containment

Table 4 Results of Analysis

Issue	Event/Component	Affects Event/Component	Affects System Unavailability	Significantly Affects Core Melt Frequency	Dominant or Non-Dominant Contributor	Risk Significance
III-5.B IX-3	Component Cooling Piping	Yes	No	-	-	Low
III-8.A	Transients	No	-	-	-	Low
III-10.A	Valves	Yes	Yes	Yes	Non-DOM	Medium
V-5	Small LOCA	No	-	-	-	Low
V-10.A	Primary Leakage to Environment	No	-	-	-	Low
V-11.A V-11.B	LOCA Outside Containment	Yes	Yes	No	-	Low
VI-4	Containment Integrity	Yes	No	-	-	Low
VI-10.A	RPS sensors/ relays	No	-	-	-	Low
VII-1.A	RPS Sensor Channels	Yes	Yes	Yes	Non-DOM	Medium
VII-3	AC powered instrumentation	No	-	-	-	Low
VIII-3.B	DC Power Supplies	Yes	Yes	No	-	Low
VIII-4	Containment Integrity (Elec.)	No	-	-	-	Low
IX-5	(a)Electrical Equipment Room Ventilation	Yes	Yes	Yes	DOM	High
	(b)Diesel Generator Ventilation	Yes	Yes	No	-	Low
	(c)DC Power Supplies for RDS/CS	Yes	Yes	Yes	DOM	High
XV-8 XV-18	Offsite Consequences	No	-	-	-	Low

Table 5

Classification of Issues Importance to Risk

High

IX-5	Ventilation Systems

Medium

III-10.A	Thermal Overload Protection
VII-1.A	RPS Isolation

Low

III-5.B	Pipe Break Outside Containment
III-8.A	Loose Parts Monitoring
V-5	RCPB Leak Detection
V-10.A	Residual Heat Removal System Heat Exchanger Tube Failure
V-11.A	Isolation of High and Low Pressure Systems
V-11.B	RHR Interlock Requirements (Systems and Electrical)
VI-4	Containment Isolation System
VI-10.A	Response Time Testing
VII-3	Safe Shutdown Systems
VIII-3.B	DC Bus Voltage Monitoring
VIII-4	Electrical Penetrations of Reactor Containment
IX-3	Service and Cooling Water Systems
XV-8	Control Rod Misoperation
XV-18	Radiological Consequences of Main Steam Line Failure Outside Containment

IV. Analysis

Following is the analysis for each topic to determine its importance to risk.

III-5.B Pipe Break Outside Containment
IX-3 Station Service and Cooling Water Systems

1. NRC Evaluation

Of the systems analyzed for topic IX-3 only the fire protection system was considered essential. There are potential single failures that could fail the fire protection system. The service water system, reactor cooling water system and demineralized water system are not important to safety as defined in Regulatory Guide 1.105, "Instrument Setpoints."

Topic III-5.B identified the screen house as a location where a pipe break outside the containment could affect the operation of safety systems. Flooding of the screen house could result from piping breaks in the service water system or the circulating water system. This could affect the operation of the fire protection pumps which are located in the screen house.

2. NRC Recommendation

The licensee should verify the existence of procedures which would ensure that system flow requirements are met for the fire protection system. There may be a need for system modification to eliminate potential passive single failures in the fire protection system. Further analysis should be performed to evaluate possible flooding effects in the screen house.

3. Systems Affected

The systems directly affected by this issue are the service water system, the reactor cooling water system, the demineralized water system and the fire protection system.

4. Comments

Based on NRC review of the service and cooling water systems for the Big Rock Point, only the fire protection system is considered essential and within the scope of topic IX-3.

5. Analysis

This analysis will only address the effect of piping system failures on the fire protection system, since the NRC has judged that the service water system, reactor cooling system and demineralized water system are not important to safety as defined in Regulatory Guide 1.105, "Instrument Setpoints."

Based on the recent plant visit, there are a total of 61 pipe segments within the screen house. Any single failure within those 61 pipe segments would result in a fire protection system failure.

Among those 61 pipe segments in which a passive failure would fail the entire system, 49 are greater than 3 inch in diameter; the other 12 are less than 3 inch in diameter. From the Reactor Safety Study (WASH-1400) the failure rate for large pipe, diameter greater than 3 inch, is $1x10^{-10}$/hr per pipe section and for small pipe, diameter less than 3 inch, $1x10^{-9}$/hr per pipe section. When the fire protection system is used in response to a core melt sequence initiator the mission time would be approximately 20 hours (based on data used in the Big Rock Point PRA). With this assumption the total failure probability contribution from the pipe segments is:

$$(1x10^{-9}/hr)(20\ hr)(12) + (1x10^{-10}/hr)(20\ hr)(49) = 3.4x10^{-7}$$

The fire protection system failure probability, as stated in the Big Rock PRA, ranges from approximately 2E-3 to 3E-2, depending on the plant conditions. (For example, during a loss of offsite power with a failure of the emergency AC power system, the system failure probability is higher than during normal plant conditions.) Dominant contributors to the system failure probability include injection valve and pump failures. Comparing the pipe failure rate with the system failure rate, it is clear that the failure probability of the pipes contribute only a very small fraction of the system failure probability.

6. Conclusions

The existence of nonredundant fire protection system pipe segments within the screen house does not contribute significantly to the system failure probability. This analysis also considered those pipe segments that are not part of the fire protection system but whose failure (rupture) could lead to fire protection system pump failure. These failures did not significantly affect the system failure probability. Consequently, the risk significance of this issue is rated low.

III-8.A Loose-Parts Monitoring and Core Barrel Vibration Monitoring

1. NRC Evaluation

A loose-parts monitoring system as required by Regulatory Guide 1.133 does not exist at the Big Rock Point nuclear power plant.

2. NRC Recommendations

Install a loose-parts monitoring system to detect loose parts in the Reactor Coolant Pressure Boundary.

3. Systems Affected

Loose parts can cause transient events by causing damage within the reactor coolant system.

4. Comments

None

5. Analysis

The only concern, from a risk perspective, of loose parts is that they may cause a transient which challenges the plant and its safety systems. There is ample data on transients to show that this effect is negligible. That is because the historical transient rate is so high, several per reactor year, and the historical contribution to this frequency by loose parts has been negligible. Eliminating loose-parts-induced transients will have virtually no effect on the transient frequency and almost no effect on risk.

6. Conclusions

Eliminating loose-parts-induced transients by installing a loose-parts monitoring system would have no effect on risk. We therefore rank the risk significance of this issue as low.

III-10.A Thermal Overload Protection for Motors of Motor-Operated Valves (MOVs)

1. NRC Evaluation

Thermal-overload protection for motors of motor-operated valves at Big Rock Point meets current licensing criteria with the exception that the thermal overload trip setpoints are not periodically tested.

2. NRC Recommendation

The NRC recommends that the testing of control systems for safety related valves be modified to include a periodic test or replacement of thermal-overload devices.

3. Systems Affected

The systems directly affected by this issue are the shutdown cooling system, fire protection system, recirculation line isolation system, post incident system, condensate system and emergency condenser system.

4. Comments

The concern is that a spurious trip of a thermal overload protection device could cause a safety-related valve not to open during accident conditions, even though nothing is wrong with the valve.

5. Analysis

At Big Rock Point there are 30 motor operated valves which are supplied power from diesel-generator-backed or station battery-backed buses. None of the DC valves have thermal-overload protection devices. All the AC valves (21) have thermal-overload protection devices which are not bypassed. These 21 AC motor-operated valves involve 6 systems (post incident system, emergency condenser system, fire protection system, recirculation line insolation system, condensate system and shutdown cooling system). Using the Big Rock Point PRA as reference, these 6 systems were analyzed to determine the possible contribution of thermal overload protection device failures to the system failure probabilities and ultimately to the plant core melt frequency.

Post Incident System

There is only one motor-operated valve (MO-7066) involved in this system. The failure rate per demand of a motor-operated valve can be found in Appendix III of the Big Rock Point PRA on Table III-3; this failure rate is:

$\lambda_D(\text{MOV}) = 7.07\text{E-}3/\text{d}$

If besides the normal mechanic failure mode, we have in addition the TOL failure mode (due to sepoint draft), the new failure rate of the MOV is:

$$\text{MOV failure rate} = \begin{pmatrix}\text{MOV failure rate due}\\ \text{to mechanical failure}\end{pmatrix} + \begin{pmatrix}\text{MOV failure rate due to}\\ \text{TOL setpoint drift}\end{pmatrix}$$

$$= 7.07E\text{-}3/d + (1-e^{-\lambda t})$$

$$= 7.07E\text{-}3/d + \left[1-e^{-(.67E-6)(175000)}\right]$$

$$= 0.12.$$

The failure rate for the setpoint drift of a TOL device (.67E-6/hr) is based on data in the IEEE-500 for operation of a thermal device at an improper signal level. The fault exposure time of 20 years (approximately 175000 hrs) assumes the TOL device has never been properly tested.

An examination of the post incident system fault tree in Appendix II of the Big Rock Point PRA shows that the failure of MO-7066 does appear in the fault tree. For the failure of MO-7066 to affect the post incident system it must occur in conjunction with the failure of manual valves FPI-5 and VPI-10. The loss of flow through these three valves will result in the loss of flow to the post incident system heat exchanger. The failure probability used for FPI-5 in the Big Rock Point PRA was 1E-4. The combination of this failure and the failure of MO-7066 has a probability of (1E-4)(.12) = 1.2E-5 if the failure of the thermal overload device is included in the failure of MOV-7066. The failure rate of the post incident system used in the Big Rock Point PRA was on the order of magnitude of 10^{-2}. The failure combinations containing the failure of MO-7066 (including thermal overload device failure) does not significantly contribute to the system failure probability.

Recirculation Line Isolation System

There are 8 MOVs in this system (N001-A, N001-B, N002-A, N002-B, N003-A, N003-B, N006-A, N006-B) that have thermal overload devices. Valves N006-A and N006-B do not appear in any fault tree analysis within BRP's PRA. Therefore we may assume they do not contribute to the system failure rate. The other 6 valves (N001-A, N001-B, N002-A, N002-B, N003-A, and N003-B) are normally open and the failure of the valve to open or close does not appear in the fault tree analysis. Therefore, a change in failure probability (for failure to open) due to TOL device setpoint drift does not affect the system failure probability.

Emergency Condenser System

The MOVs (MO-7052 and MO-7062) involved in this system, are in the normally open position and are not required to change position following an initiating event. Therefore, the failure probability due to TOL device setpoint drift does not affect the system failure probability.

Condensate Cooling System

There are 2 MOVs (MO-7073 and MO-7074) involved in the condensate cooling system. TOL device failure shows a small contribution to the condensate system failure probability. However, there are 3 dominant sequences that could be affected by the failure to restore the condenser where the failure to restore the condenser could be affected by these 2 MOVs. However, the value used for the failure to restore the condenser in these 3 dominant sequences is 1.0 (i.e., it is assumed that the condenser will not be recoverable during any of these three dominant accident sequences). Therefore, any contribution due to an increase in the failure probability of these valves will have an insignificant impact on these dominant sequences.

Shutdown Cooling System

MOVs 7056, 7057, 7058, and 7059 are part of the shutdown cooling system, and appear to directly affect the top event (T.E.) of the system. The shutdown cooling system is one of the systems that provides long term cooling following an initiating event. Failure of these systems could eventually lead to a core melt. In the BRP PRA analysis, the contribution from the failure of the MOVs (7056-7059) to the system failure probability of 3.1E-2 is 2.83E-2. This implies that all other mechanical failures contribute only 3E-3 to the system failure probability. This value was calculated without consideration of the failure of the MOV contributed by the failure of thermal overload mechanism.

To consider the impact of the failure of the thermal overload device on the system the failure probability for each valve is increased from 7.07E-3 to 1.2E-1. The setpoint drift failure of the thermal overload device contributes approximately 1.1E-1 to this failure probability. The failure of any one of these four valves will fail the shutdown cooling system. Using this value for the MOV failure probability the system failure probability is calculated to be 4.8E-1. The system failure probability is dominated by the failure of the thermal overload devices.

If a testing period of one (1) year is assumed for the thermal overload mechanism of the MOVs, the failure probability of each valve would be

$$= \begin{pmatrix}\text{MOV failure}\\ \text{probability}\end{pmatrix} + \begin{pmatrix}\text{thermal overload failure}\\ \text{probability due to setpoint drift}\end{pmatrix}$$

$$= \lambda_D \quad + \quad 1/2\lambda t$$

$$= 7.0E\text{-}3 + 1/2(.67E\text{-}6)(8760)$$

$$= 7.0E\text{-}3 + 2.9E\text{-}3$$

$$= 1E\text{-}2.$$

The contribution to the system failure probability of the cut sets not involving the MOVs is 3E-3. Therefore the system failure probability assuming yearly testing of the thermal overload protection devices would be 4.3E-2. This is still slightly larger than the value used for this system in the Big Rock Point PRA.

The effect of the change in the system failure probability on the core melt frequency is evaluated concurrently with the effect of the fire protection system. This part of the analysis is presented after the fire protection system analysis.

Fire Protection System

The primary function of the fire protection system under consideration here is that it provides the core spray function at Big Rock Point. In this capacity the fire protection system supplies makeup to the core.

The MOVs affected in the Fire Protection System include MOVs 7068, 7069, 7070, and 7071. Of these valves, MOV 7069 is normally open and does not change position during an accident sequence and thus any effect due to thermal overload mechanism failure would have no effect on the system operation. The failure to open/close of MOV 7068 does not appear in the Big Rock Point PRA. Therefore the failure of the thermal overload device would have no effect on the PRA results.

The failure of MOVs 7070 and 7071 are both present in the Big Rock Point fault tree analysis and thus any additional effect on these MOVs is likely to directly impact the failure probability of the system. (The system failure probability is dominated by random and common cause failures of the system valves and pumps.)

The fire protection system failure probability used in the Big Rock Point PRA was of the order of magnitude of 10^{-3} to 10^{-2}. The value varied depending on plant conditions (e.g., offsite power available, emergency AC power available) and the duration of the demand on the system. Failure of the two MOVs, 7070 and 7071, appeared in cut sets contributing 6.76E-4 to the system failure probability. These cut sets consist of the failure of one of the two AC operated core spray valves (7070, 7071) and the failure of one of the two DC operated valves (7051, 7061). The failure probability of these four cut sets[1] is the contribution of random valve failures to the system failure probability. If the AC powered MOV failure probability is modified to include the probability of thermal overload device failure, its value will increase by .11 from 1.3E-2 to 1.2E-1. (1.3E-2 is the value used for fire protection system valve failure probability in the Big Rock Point PRA.) Using this in the cut sets containing random failures of the core spray valves yields a failure probability of the fire protection system (core spray mode) due to random valve failures of 6.4E-3 This is an increase in the system failure probability of approximately 5.7E-3.

If the thermal overload devices are tested annually the MOV thermal overload device failure probability is reduced to 3E-3. (For details see the shutdown cooling system portion of this analysis.) In this case the AC powered MOV failure probability is

$$3E-3 + 1.3E-2 = 1.6E-2.$$

1 The four cut sets are: failure of valves 7071 and 7051, failure of valves 7071 and 7061, failure of valves 7070 and 7051, and failure of valves 7070 and 7061.

Using this value the contribution to the system failure probability of cut sets of random valve failures would be

$$4\,(1.6E\text{-}2)(1.3E\text{-}2) = 8.3E\text{-}4.$$

Effects of MOV's thermal overload mechanism failure on dominant sequences

As described above, both of the affected systems are considered in the dominant sequence analysis presented in the BRP PRA report. There are a total of 81 dominant sequences considered, and of that, 22 sequences are affected by either or both systems (fire protection system and shutdown cooling system). These are listed in Table III-10.A-1. The shutdown cooling system is used when long-term cooling is needed, and the fire protection system is part of the RDS/CS system.

Table III-10.A-1 shows a list of the affected dominant sequences, the core damage frequency as shown in BRP's PRA, the core damage frequency when taking into account the failure rate of MOV's thermal overload mechanism (assuming they have never been properly tested), and the core damage frequency with a "one-year test period" considered for MOV's thermal overload mechanism.

As shown in Table III-10.A-1, with the contribution of the MOV's thermal overload mechanism failure, the change is about 11% over the original value for the total dominant sequences (9.75E-4). Such a change is considered to have a medium impact on the core damage frequency; but if an annual testing period for the thermal overload mechanism of MOV is considered, the change is reduced to an insignificant amount (~0.3% increase).

6. Conclusion

Of the 31 Motor-Operated Valves (MOVs) considered by the NRC, 26 valves were dismissed for thermal overload mechanism periodical testing due to insignificant effects on the operation of the MOVs or on the related top event. The remaining 5 MOVs are determined to significantly affect the failure of the systems of which they are a part. The affected systems are considered in the dominant sequences as determined in the Big Rock Point PRA, and thus, any contribution to the failure of these systems will directly impact the core damage frequency. The analysis shows that if the MOV's thermal overload mechanisms remain untested, the probability of core damage occurrence is increased approximately 11% over the value given in the BRP PRA study. With yearly testing implemented for the thermal overload mechanisms of these 5 valves, the increase in core damage frequency is reduced to an insignificant level (~0.3%). Since the lack of testing of the thermal overload protection yields an increase of approximately 10% in the expected Big Rock Point core melt frequency, we rate this issue to be of medium risk significance.

Table III-10.A-1. Core Damage Frequencies Calculated for the Affected Dominant Sequences

Sequence	Core damage frequency (per year): As show in BRP's PRA	With TOL's* failure contribution	With "one-year test period" implemented for TOL
TENC	1.5×10^{-7}	3.61×10^{-7}	1.51×10^{-7}
TZL	3.8×10^{-7}	8.30×10^{-6}	5.36×10^{-7}
Y_fL	4.3×10^{-7}	9.47×10^{-6}	6.13×10^{-7}
MNL	1.6×10^{-7}	3.55×10^{-6}	2.30×10^{-7}
ME_vNC	6.7×10^{-7}	1.65×10^{-6}	6.97×10^{-7}
ME_mNC	2.4×10^{-7}	5.88×10^{-7}	2.49×10^{-7}
PE_vF_sC	3.1×10^{-6}	5.24×10^{-6}	3.19×10^{-6}
PE_mF_sC	1.3×10^{-5}	2.25×10^{-5}	1.37×10^{-5}
PIF_sYC	8.5×10^{-7}	1.42×10^{-6}	8.65×10^{-7}
$PQIF_sC$	1.5×10^{-7}	2.56×10^{-7}	1.56×10^{-7}
S_1E_mC	4×10^{-6}	9.8×10^{-6}	4.15×10^{-6}
S_2C	4×10^{-7}	9.8×10^{-7}	4.15×10^{-7}
S_3E_mC	4×10^{-6}	9.8×10^{-6}	4.15×10^{-6}
UL	1.5×10^{-7}	3.2×10^{-6}	2.07×10^{-7}
UE_vUC	6.7×10^{-7}	1.65×10^{-6}	6.97×10^{-7}
UE_mUC	7.4×10^{-6}	1.82×10^{-5}	7.72×10^{-6}
WE_vC	6.7×10^{-7}	1.65×10^{-6}	6.97×10^{-7}
WE_mC	2.4×10^{-7}	5.88×10^{-7}	2.49×10^{-7}
BB_cE_vC	3.7×10^{-7}	9.07×10^{-7}	3.84×10^{-7}
BB_cZY_fC	2.0×10^{-5}	4.84×10^{-5}	2.05×10^{-5}
RR_oC	4.8×10^{-6}	1.18×10^{-5}	4.98×10^{-6}
I_1E_mC	7.9×10^{-6}	1.94×10^{-5}	8.22×10^{-6}
Subtotal	6.97×10^{-5}	1.80×10^{-4}	7.28×10^{-5}
Other sequences	9.053×10^{-4}	9.053×10^{-4}	9.053×10^{-4}
Total	9.75×10^{-4}	1.085×10^{-3}	9.78×10^{-4}
% increase over PRA's Total (i.e., 9.75×10^{-4})	0.00	11.3	0.31

* TOL = thermal overload mechanism

Table III-10.A-1 (continued)

B	- Spurious opening of turbine bypass valve
B_C	- Failure of turbine bypass valve to reclose
C	- Failure of reactor depressurization system (RDS) and core spray mode of fire protection system
E	- Emergency condenser failure
E_V	- Failure of emergency condenser valves to open
E_M	- Failure to get makeup to emergency condenser
F_s	- Failure to restore power in the short term
I	- Primary system isolation
I_1	- Interfacing system LOCA
L	- Failure of long term cooling
M	- Loss of main condenser
N	- Failure to repair main condenser
P	- Loss of station power
R	- Spurious opening of RDS isolation valve
R_o	- Failure of RDS valve to remain closed
S_1	- Small LOCA
S_2	- Medium LOCA
S_3	- Small steam line break inside containment
T	- Turbine trip
U	- Loss of instrument air
W	- Spurious closure of MSIV
Y_f	- Failure of inventory makeup
Z	- MSIV closure

V-5 Reactor Coolant Pressure Boundary Leakage Detection

1. NRC Evaluation

Current regulation criteria (Regulatory Guide 1.45) require that at least three different leakage detection systems be installed in a nuclear power plant to detect unidentified leaks from the reactor coolant pressure boundary to the primary containment. These systems should be capable of detecting a "one gallon per minute" (1 gpm) leak within one hour, should be seismically qualified and could be monitored from the control room.

Of the three required detection systems, two should be "sump level and flow monitoring" and "airborne particulate radioactivity monitoring." The third should either be "monitoring of condensate flow rate" or monitoring of airborne gaseous radioactivity." At Big Rock Point, all three required detection systems do not meet the requirements regarding sensitivity, seismic qualification, testability and alarm indication.

2. NRC Recommendation

The need for changes with respect to the required detection sensitivity and seismic qualification will be considered during the integrated safety assessment.

3. System Affected

The system affected is the primary reactor coolant system.

4. Comments

The main concern in this issue is that if the installed leakage detection systems do not work properly and small leakages in the reactor coolant pressure system are not detected in time, it could possibly lead to small breaks which can result in a small to medium loss of coolant accident (LOCA). Thus, this is a "leak-before break" issue for pipes. This evaluation does not consider the significance of leakage detection to mitigate high energy pipe breaks. It also excludes consideration of common-mode pipe break effects (e.g., pipe whip).

Seismic events do not contribute significantly to the core melt frequency at the Big Rock Point plant. There are no dominant core melt sequences initiated by a seismic event. Therefore, the lack of seismic qualification of the leakage detection systems is not risk significant.

Recent information obtained from Big Rock Point (BRP) through communication with a plant staff member, indicates that BRP is planning/or in the process of submitting additional information in regard to the sensitivity, testability and alarm indication of the leakage detection system to the NRC. This information suggests that at least two of the three detection systems at the plant will meet the required criteria of 1 gpm detection in one hour. These two systems are the radioactive particulate monitoring system and the radioactive gaseous monitoring system. The remaining system, the sump level/flow monitoring system, does meet the requirement of 1 gpm limit but is sampled every 8 hours. Thus, we assume that only 2 out of the 3 required systems are in compliance.

5. Analysis

The reactor coolant pressure boundary leakage detection system at the Big Rock Point plant includes the three NRC recommended systems (i.e., sump level/flow monitoring, radioactive gaseous and particulate monitoring). The status of these systems is described in Table V-5-1. Based on the available information, it is suggested that the radioactive gas and particulate monitoring systems are in compliance with the requirements. Only the sump level/flow system does not meet the required criteria.

This analysis is to show the unavailability of the leakage detection system at Big Rock Point witn two of the three required systems meeting the criteria. The total demand failure rate can be calculated as follows:

$$q_{tot} = q_{rad.gas} \times q_{rad.\ part} \qquad (1)$$

where q_{tot}, $q_{rad.\ gas}$, $q_{rad.\ part}$ are the demand failure rate of the detection systems, the radioactive gaseous monitoring system, and the radioactive particulate monitoring system, respectively.

The demand failure rate for each system can be calculated using the following equation:

$$q_i = \frac{\lambda i}{2}\ (t) \qquad (2)$$

where q_i is the demand failure rate of the system, λ_i is the component failure rate per hour, and t, the time period between each test. In this analysis we assume that the system is tested once every refueling cycle or approximately every 12 months. Thus, the total unavailability of the system is

$$\begin{aligned} q_{tot} &= [1/2\ (1.4\times10^{-5}/\text{hr})(8640\ \text{hr})]\ [1/2\ (1.4\times10^{-5}/\text{hr})(8640)] \qquad (3) \\ &= 3.7\times10^{-3}/d \end{aligned}$$

The next step is to evaluate the contribution of the failure of the leakage detection system to the initiation frequency of a small and a medium loss of coolant accident (LOCA). The event can be represented as a small leak developing into a small break or a medium break in the reactor coolant pressure boundary system. (The average frequencies of a small and a medium LOCA at Big Rock Point are 1.0×10^{-3} and $1.0\times10^{-4}(yr^{-1})$ respectively. Such an event represents only a small fraction of the many events leading to a small LOCA such as pipe rupture, valve stuck open, failure of main reactor pump seal..., but the exact fraction for this contribution is undetermined. For this analysis, let us conservatively consider that all small or medium LOCAs are initiated by small leaks. Then the frequencies for a small and medium LOCA can be calculated as follows:

$$F_2 = \begin{bmatrix}\text{frequency of small leaks}\\ \text{becoming small LOCAs}\end{bmatrix} \begin{bmatrix}\text{failure rate of the}\\ \text{leakage detection system}\end{bmatrix} \quad (4)$$

$$F_3 = \begin{bmatrix}\text{frequency of small leaks}\\ \text{becoming medium LOCA}\end{bmatrix} \begin{bmatrix}\text{failure rate of the}\\ \text{leakage detection system}\end{bmatrix} \quad (5)$$

or $$F_2 = [1\text{x}10^{-3}][3.7\text{x}10^{-3}] = 3.7\text{x}10^{-6} \quad (6)$$

$$F_3 = [1\text{x}10^{-4}][3.7\text{x}10^{-3}] = 3.7\text{x}10^{-7} \quad (7)$$

For the case where all three detection systems are available, the unavailability of the detection systems is:

$$q_T = [1/2(5\text{x}10^{-6})(8640)][1/2(1.4\text{x}10^{-5})(8640)][1/2(1.4\text{x}10^{-5})(8640)] \quad (8)$$
$$= 7.9\text{x}10^{-5}$$

The contribution to the frequencies of a small and medium LOCA is again calculated as below:

$$F_2 = [1\text{x}10^{-3}][7.9\text{x}10^{-5}] = 7.9\text{x}10^{-8} \quad (9)$$

$$F_3 = [1\text{x}10^{-4}][7.9\text{x}10^{-5}] = 7.9\text{x}10^{-9} \quad (10)$$

Comparing the above values for F_2 and F_3 to those estimated for the case where only 2 detection systems are available, it represents an order of magnitude decrease. The assumption has been made that with leakage detection it is possible to prevent pipe break LOCAs. The existence of two leakage detection systems that meet current NRC criteria would reduce the pipe break LOCAs frequencies to a point where they no longer contribute significantly to the Big Rock Point core melt frequency. Therefore the addition of a third detection system would have little effect on the core melt frequency. Additionally, there are the LOCA type events for which the leakage detection system would not provide any benefit such as inadvertent opening of a safety/relief valve (a frequency of approximately 2E-2/yr) and reactor pump seal leakage (on the order of 10^{-3} to 10^{-2}/yr). These are rapidly developing events whose frequency of occurrence cannot be reduced through the use of detection systems.

6. Conclusion

The leakage detection systems incorporated in the reactor coolant pressure boundary system include all three recommended mechanisms. Of the three currently present, one does not meet the required criteria of detecting 1 gpm in 1 hour. The analysis shows that even under conservative assumptions, the failure rate of the leakage detection systems contributed to the initiation frequency of a small or medium LOCA is insignificant when compared to other initiation sequences. Thus, the reduction in unavailability of the leakage detection systems, and therefore the pipe break LOCA frequency, would not significantly affect the core melt frequency at the Big Rock Point plant. Therefore, the risk significance of this issue is ranked as being low.

Table V-5-1 Reactor Coolant Pressure Boundary Leakage Monitoring Systems

System	Sensitivity (Leak Rate)	Time Required to Achieve Rated Leak Rate	Test and Maintenance Schedule	Monitoring Schedule	Failure Rate
1. Sump Level (Inventory) Monitoring	1 gpm	Poor	Every refueling	Once every 8 hours	5.0x10-6/hour
2. Airborne Particulate Radioactivity Monitoring	1 gpm	1 hour	Every refueling	Continuously	1.4x10-5/hour
3. Airborne Gaseous Radioactivity Monitoring	1 gpm	1 hour	Every refueling	Continuously	1.4x10-5/hour
4. Containment Atmosphere Humidity Monitoring	1 gpm	1 hour			

V-10.A Residual Heat Removal Heat Exchanger Tube Failure

1. NRC Evaluation

The Big Rock Point nuclear reactor plant does not meet the current criteria regarding monitoring of the primary coolant for impurities that could be contained in leakage from the reactor cooling water system (RCWS). Furthermore, the monitoring of potential leaks to the environment from the primary cooling system through the reactor cooling water system into the service water system (SWS) does not meet the current criteria.

2. NRC Recommendation

Recommendations are under review by the NRC.

3. Systems Affected

The systems affected by this issue are the primary coolant system, the residual heat removal system, the reactor cooling water system, and the service water system.

4. Comments

During normal operation of the shutdown cooling system, the primary side (primary coolant system) of the shutdown cooling heat exchangers is at a lower pressure (~11.5 psig) than the secondary side (RCWS)(~70 psig). The pressure differential allows leakage from the RCWS into the primary coolant system. The primary side (RCWS) of the reactor cooling water heat exchangers is at a lower pressure (< a few psig) than the secondary side (SWS) (20-45 psig). This pressure differential allows leakage from the SWS into the RCWS.

At present the RCWS has a means of detecting leakage into or out of the system via a low level alarm on the surge tank. The alarm annunciates in the control room. Leakage of impurities from the SWS into the primary coolant system would also be detected by twice weekly sampling of the reactor cooling water. The SWS also has a low level alarm and twice weekly sampling (during system operation).

During startup of the shutdown cooling system, the primary side (primary coolant) of the shutdown cooling heat exchangers is at a higher pressure (150-280 psig) than the secondary side (reactor cooling water at ~70 psig). This pressure differential allows leakage out of the primary coolant system into the RCWS if there is a SCS heat exchanger tube failure.

5. Analysis

A simplified fault tree for the possible leakage paths into the primary coolant system is shown in Figure V-10.A-1. As can be seen from the fault tree, one of the two shutdown cooling system heat exchangers and one of the two reactor cooling water heat exchangers must fail while the shutdown cooling system is in operation in order for leakage into the primary coolant system to occur. The frequency of leakage from the environment into the primary coolant system is

2(frequency of failure of SCS heat exchanger)
x 2(possibility of failure of RCW heat exchanger).

The frequency of failure of the SCS heat exchangers or the RCW heat exchangers was calculated by using the upper bound for a small diameter pipe break from WASH-1400. This failure rate is $3x10^{-8}$/hr. Assuming an annual refueling and consequently annual testing of the heat exhangers, the probability of failure of the heat exchanger is calculated from the relationship $\lambda T/2$. In this relationship, λ is the failure rate of the component and T is the time between tests. Based on this, the probability of failure of the heat exchanger is $1.3x10^{-4}$/yr.

The frequency of a heat exchanger tube failure can be calculated by converting the failure rate from an hourly failure rate to a yearly frequency. The frequency would be λT where T is 8760 hours/yr. From this equation the frequency of an SCS heat exchanger tube failure would be $2.6x10^{-4}$/yr.

Thus, the frequency of leakage from the environment into the primary coolant system through the SCS, RCWS and SWS is conservatively calculated to be

$$2(2.6x10^{-4}/yr) \times 2(1.3x10^{-4}) = 1.3x10^{-7}/yr.$$

Considering the low frequency of this event and the relatively low importance of the consequences of this leakage compared to the consequences of a core melt accident, it is clear that this event should not contribute significantly to the overall risk of the plant.

The above analysis also applies to the event of leakage out of the primary coolant system into the service water system.

6. Conclusions

The frequency of a leakage from the primary coolant system to the environment (or from the environment to the primary coolant system) was conservatively calculated to be $3.2x10^{-7}$/yr. Considering the consequences of a leakage and the consequences of a core melt accident, it is clear that either event does not have a significant effect on the overall risk due to operation of this plant. (This analysis did not consider the long term effects on primary system integrity due to inleakage.) Thus, we rank the risk significance of this issue as low.

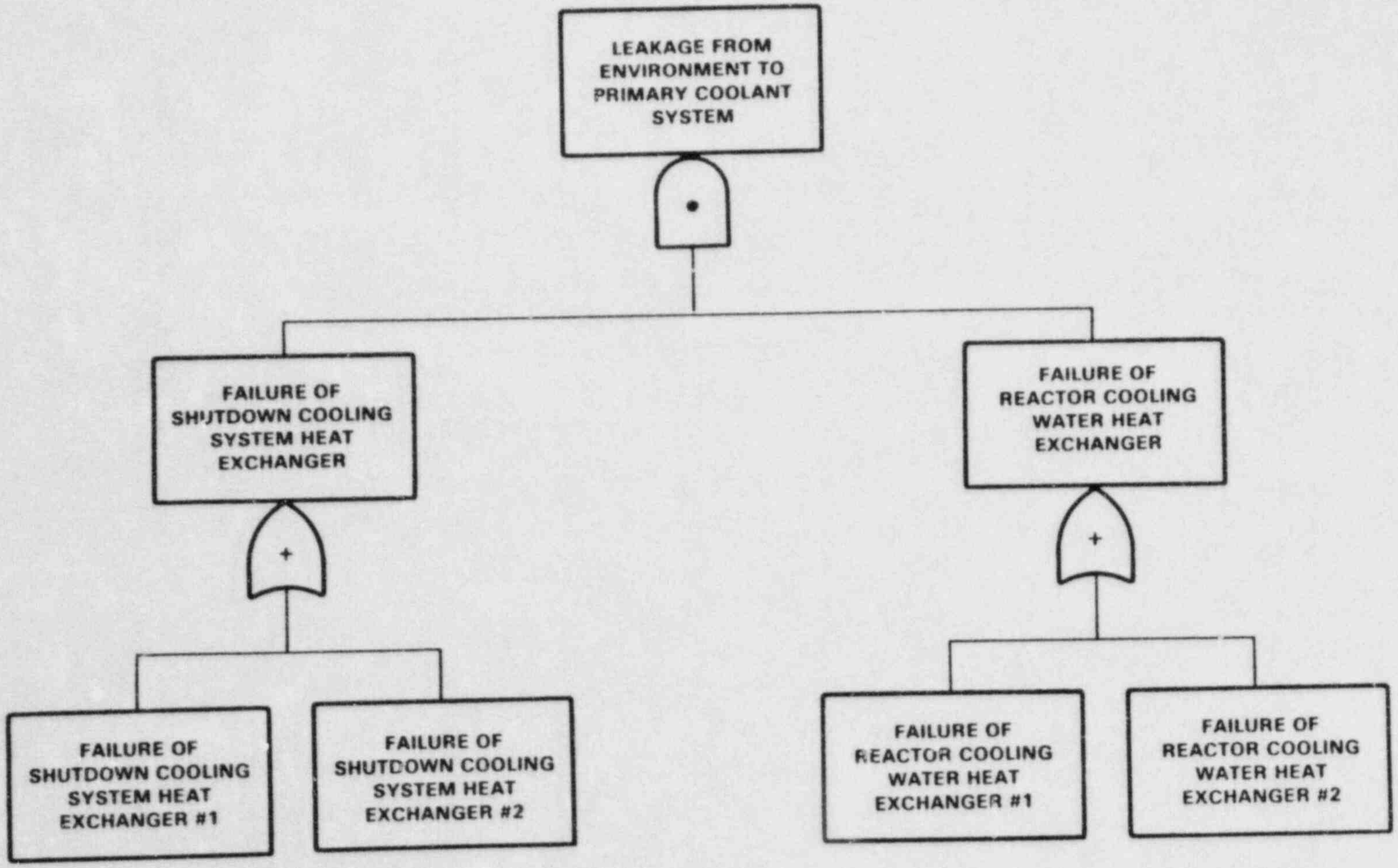


Figure V-10.A-1. FAULT TREE FOR THE EVENT "LEAKAGE FROM ENVIRONMENT TO PRIMARY COOLANT SYSTEM"

V-11.A Requirement for Isolation of High and Low Pressure Systems
V-11.B RHR Interlock Requirements

1. NRC Evaluation

There are two systems at Big Rock Point with a direct interface to the RCS pressure boundary and with lower design pressure than the RCS design pressure. The systems are the shutdown cooling system (SDCS) and the core spray system (CSS). They do not meet the current licensing criteria contained in SRP 6.3 and BTP RCS-5-1 for isolation of high pressure and low pressure systems.

Both the suction side and the discharge side of the SDCS have two isolation MOVs. The MOVs cannot open if the RCS pressure is higher than the SDCS design pressure. The MOVs automatically close on high RCS pressure and each has position indication in the control room. The interlocks for these MOVs are not diverse because only one interlock contact and one pressure measuring system are used.

The CSS consists of two separate lines supplying the reactor vessel through two MOVs and a check valve in each line. Each MOV has position indication in the control room. The core spray system design pressure is 150 psig. The MOVs do not close automatically upon clearance of the initiation signal or on increasing the RCS pressure above the CSS design pressure. There are no interlocks to prevent opening of the CSS MOVs from the control room when the RCS pressure exceeds the CSS design pressure.

2. NRC Recommendations

Modification of the SDCS is not necessary because the current design satisfies the single failure criteria. Further modifications to provide diversity or redundancy will not provide a significant improvement in the protection of the public health and safety.

Initial staff recommendations were that control of the CSS valves should be modified to satisfy the interlock provisions of SRP Section 6.3 and BTP RSB-5-1. Subsequent to this analysis this recommendation has been changed. Since the use of a check valve and two tested MOVs meet the single failure criteria.

3. Systems Affected

The systems affected by this issue are the SDCS and the CSS.

4. Comments

Current NRC requirements related to the isolation of RHR system contained in BTP RSB-5-1 are:

1. The suction side must be provided with the following isolation features:

    a. Two power-operated valves in series with position indicated in the control room.

b. The valves must have independent and diverse interlocks to prevent opening if the reactor coolant system (RCS) pressure is above the design pressure of the RHR system.

c. The valves must have independent and diverse interlocks to ensure at least one valve closes upon an increase in RCS pressure above the design pressure of the RHR system.

2. The discharge side must be provided with one of the following features.

   a. The valves, position indicators, and interlocks described in (1)(a) through (1)(c) above.

   b. One or more check valves in series with a normally-closed power-operated valve which has its position indicated in the control room. If this valve is used for an Emergency Core Cooling System (ECCS) function, the valve must open upon receipt of a safety injection signal (SIS) when RCS pressure has decreased below RHR system design pressure.

   c. Three check valves in series.

   d. Two check valves in series, provided that both may be periodically checked for leak tightness and are checked at least annually.

Current NRC isolation requirements for Emergency Core Cooling System (ECCS) are contained in SRP 6.3. Isolation of the ECCS to prevent overpressurization must consist of one of the following:

1. One or more check valves in series with a normally-closed motor-operated valve (MOV) which is to be opened upon receipt of a SIS when RCS pressure is less than the ECCS design pressure.

2. Three check valves in series.

3. Two check valves in series, provided that both may be periodically checked for leak tightness and are checked at least annually.

The SDCS isolation provisions do not meet the current licensing criteria since the interlocks for the isolation valves are not diverse as required by BTP RSB-5-1.

The CSS does not meet the isolation criteria of current licensing requirements since no interlocks exist to prevent opening of isolation valves from the control room when the RCS pressure exceeds the CSS design pressure.

5. Analysis

The NRC has examined the Big Rock Point SDCS interlocks (SEP Topics V-10-B, VII-3 and VIII-1.A) and found them to be acceptable. (The interlocks provided for the SDCS consist of two pressure sensors and relays that provide protection for both isolation valves on the SDCS suction and discharge lines. There is adequate electrical protection within the interlock to prevent a common mode failure of both pressure signals.) Thus, no analysis of the SDCS will be performed here. The analysis of the CSS is described below.

The CSS consists of two lines. There is a check valve between two MOVs in each line and it is tested monthly.

During the testing of the core spray system it is possible that the operator could inadvertently open both normally closed MOVs. If the operator opens both MOVs by mistake and there is a rupture in the check valve, then a loss of the core spray system and an interfacing system LOCA will result. The frequency of this combination of events can be calculated as a product of the probability of an operator error during test, the probability of a check valve reverse leakage and the frequency of the test.

The Handbook of Human Reliability (NUREG/CR1278) gives a probability of human error in restoring a valve (during a test) as 0.001. The probability of failure of the check valve can be calculated from the relationship $\lambda T/2$. In this relationship, λ is the failure rate of the component and T is the time between tests. With monthly check valve surveillance the valve failure probability is

$$1/2(3E-7)(720)$$
$$= 1.1E-4$$

where 3E-7/hr is the valve leakage probability from WASH-1400.

The failure of the core spray system isolation in this case becomes the probability of the human error (0.001) of restoring the MOVs times the probability of failure of the check valve (1.1×10^{-4}) leading to a LOCA probability of 1.1E-7. Since the test is conducted 24 times a year (once a month on two injection lines), the frequency of an interlock failure is 2.6×10^{-6}/yr.

An alternative interlock system would use a pressure sensor to automatically close the MOVs upon RCS pressure increasing above the core spray system design pressure. Based on WASH-1400 data, the frequency of failure of pressure sensors is 2.7E-7/hr. Assuming annual testing of the pressure sensor, the pressure sensor unavailability is 1/2(2.7E-7) (8760) = 1.4E-3. The failure of the CSS becomes the probability of failure of the check valve times the unavailability of the pressure sensor times the probability of human error of restoring the MOVs, leading to a LOCA probability of 1.5E-10. The LOCA frequency would be 24 times this probability, 3.6E-9/yr.

Considering the low frequency (2.6E-6) of failure of the current CSS isolation design, it is clear that this event should not contribute significantly to the overall risk of the plant. Diverse pressure interlocks in the CSS appear to be unnecessary.

6. Conclusions

Based on NRC's recommendations, no modification of the shutdown cooling system isolation is necessary. The results of the probabilistic analyses of the interlock systems for previous SEP plants would tend to support this conclusion. For example, the analysis performed for the Haddam Neck plant (SAI report SAI-83-128-WA) reached the same conclusion. For a system such as a shutdown cooling system a single pressure interlock is sufficient to insure that the risk from an interfacing LOCA, in that system, is not a significant contributor to the core melt risk.

The current core spray system pressure interlock has a frequency of failure on the order of 2.6E-6/yr. The addition of an automatic pressure interlock mechanism reduces this frequency to 3.6E-9/yr. The core melt frequency at the Big Rock Point, based on the Big Rock Point PRA, is 9.8E-4/yr. An event with a frequency of 2.6E-6/yr does not significantly affect this core melt frequency. Since the contribution of these frequencies to the overall core melt frequency is judged to be small, no changes in the core spray system isolation seem to be necessary. Thus, we rank the risk significance of this issue as low.

VI-4 Containment Isolation System

1. Evaluation

Being an older design, many of Big Rock Point's containment penetrations do not meet the current General Design Criteria. Table VI-4-1 lists these penetrations and their areas of non-compliance.

2. Recommendation

The licensee should change the penetration configurations to meet the General Design Criteria (GDC).

3. Systems Affected

The ability of the containment penetrations to isolate and insure containment integrity is affected by the configurations of the penetrations.

4. Comments

The containment penetrations were analyzed, those found not in compliance categorized into five cases depending on the particular configuration of the penetration. The unavailabilities of the containment penetrations were calculated using the available information which did not include any details on the isolation valves themselves (e.g., control circuits, power sources, etc.). Therefore, the results presented are not intended as a definitive analysis, but instead are meant for comparison purposes only.

5. Analysis

There are nine penetrations where the particular configurations do not conform to the General Design Criteria. The five cases presented characterize the penetrations which have an identical configuration and therefore are treated collectively. From one to four penetrations are listed for each case.

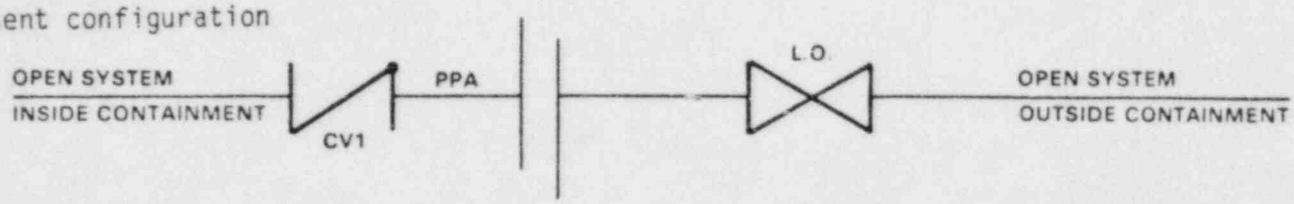
Each penetration case is drawn in both the "before" and "after" configuration in the respect of their meeting the GDC. As mentioned previously, detailed information on the valves used for containment isolation was not available, therefore, the analysis does not consider either control or motive power, or isolation signals received by the valves. Typically, local leak rate checks for the containment penetrations are performed semi-annually, resulting in a fault exposure time for most events of 2190 hours.

Only those penetrations four inches or larger in diameter are considered significant in terms of possible containment leakage (see WASH-1400, Appendix II, Section 5.12). The data used in this analysis is presented in Table VI-4-2.

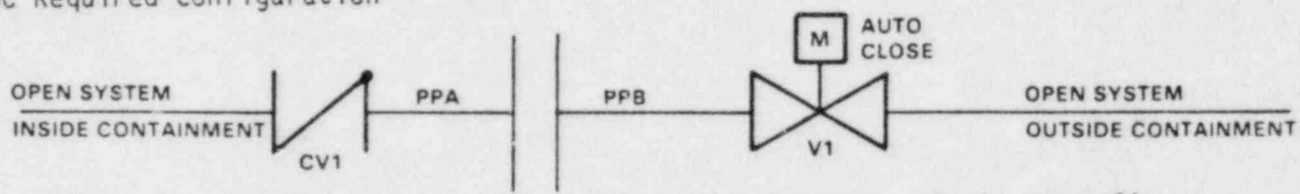
Case I:

Applies to Penetrations #H-27 and H-36.

Present configuration



GDC Required configuration



The boolean equations which describe the unavailabilities of these configurations are as follows:

Before: CV1 + PPA

After: (CV1 + PPA) * (PPB + V1)
Using the failure rates presented in Table VI-4-2, the following unavailabilities were calculated.

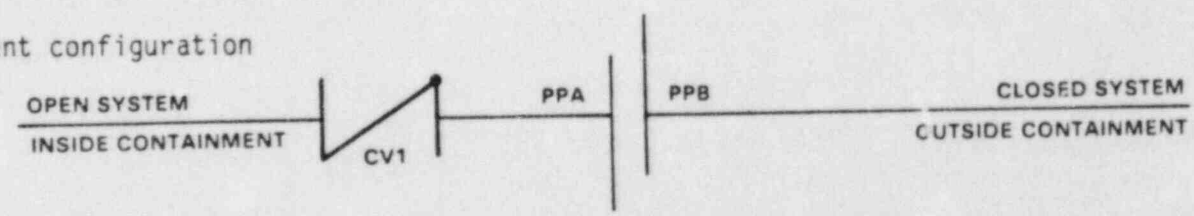
Case I before: (6.8E-4) + (2.2E-7)
6.8E-4

Case I after: (6.8E-4 + 2.2E-7) * (2.2E-7 + 1E-3)
6.8E-7

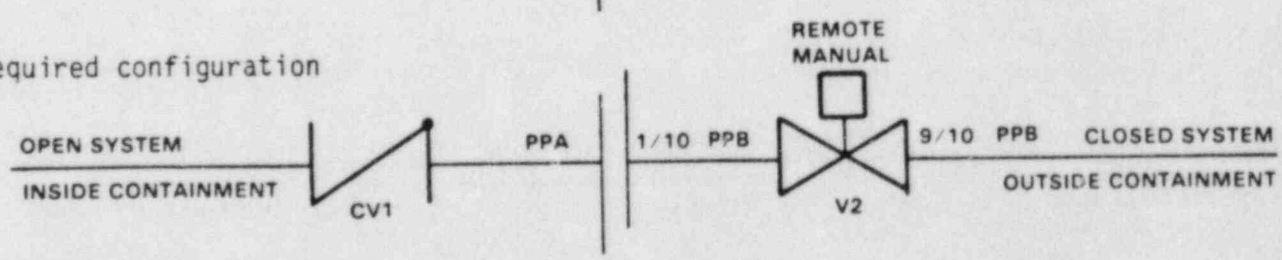
Case II:

Applies to Penetration #H-113.

Present configuration



GDC required configuration



The boolean equations which describe the unavailabilities of these configurations are as follows:

Before: (CV1 + PPA) * PPB

After: (CV1 + PPA) * [1/10 PPB + (V2 * 9/10 PPB)]

Using the failure rates presented in Table VI-4-2, the following unavailabilities were calculated.

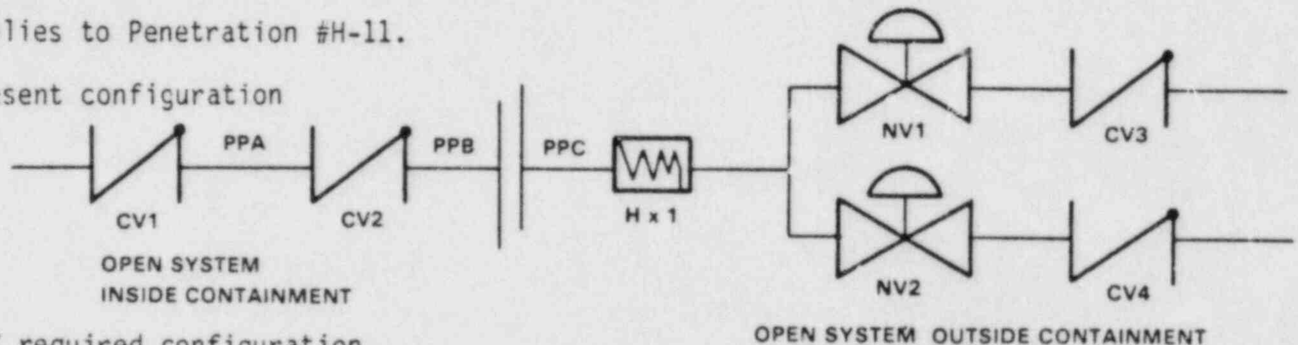
Case II before: (6.8E-4 + 2.2E-7) * (2.2E-7)
1.5E-10

Case II after: (6.8E-4 + 2.2E-7) * [2.2E-8 + (0.1 * 2.0E-7)]
2.8E-11

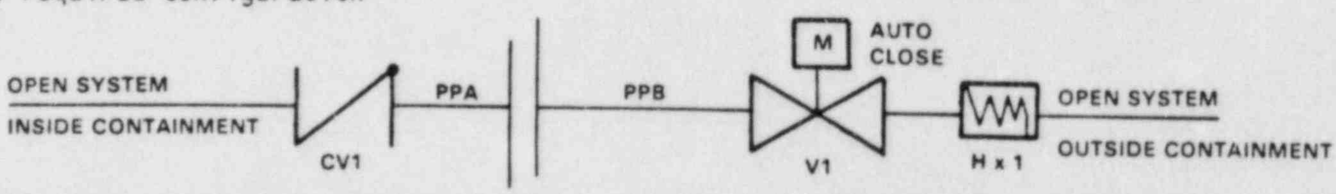
Case III:

Applies to Penetration #H-11.

Present configuration



GDC required configuration



The boolean equations which describe the unavailabilities of these configurations are as follows:

Before: [(CV1 + PPA) * CV2 + PPB] * (PPC + HX1 + NV1 + NV2 + CV3 + CV4)

After: (CV1 + PPA) * (PPB + V1)

Using the failure rates presented in Table VI-4-2, the following unavailabilities were calculated.

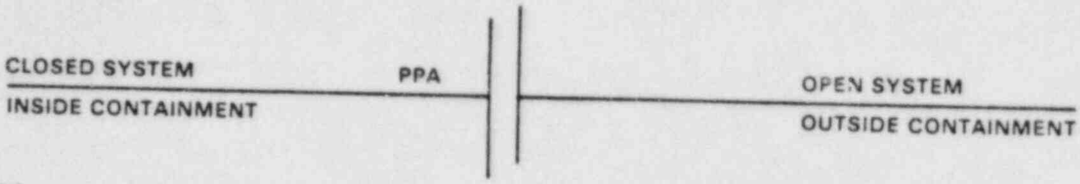
Case III before: [(6.8E-4 + 2.2E-7) * 6.8E-4 + 2.2E-7] *
(2.2E-7 + 2.2E-6 + 2.2E-6 + 2.2E-6 + 6.8E-4 + 6.8E-4).
9.3E-10

Case III after: (6.8E-4 + 2.2E-7) * (2.2E-7 + 1E-3)
6.8E-7

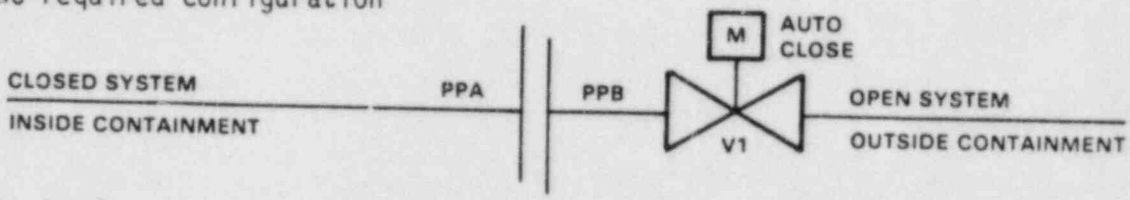
Case IV:

Applies to Penetrations #H-9, H-12, H-13, and H-14

Present configuration



GDC required configuration



The boolean equations which describe the unavailabilities of these penetrations are as follows:

Before: PPA

After: PPA * (PPB + V1)

Using the failure rates presented in Table VI-4-2, the following unavailabilities were calculated.

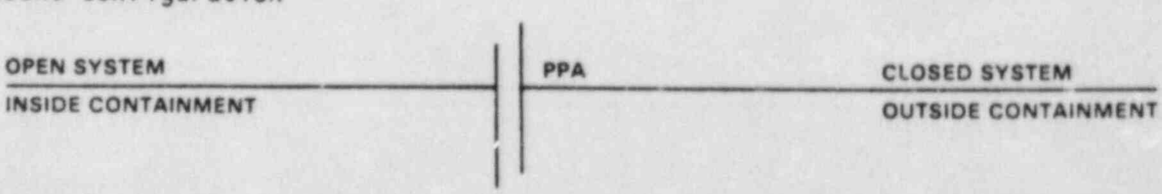
Case IV before: 2.2E-7

Case IV after: 2.2E-7 * (2.2E-7 + 1E-3)
2.2E-10

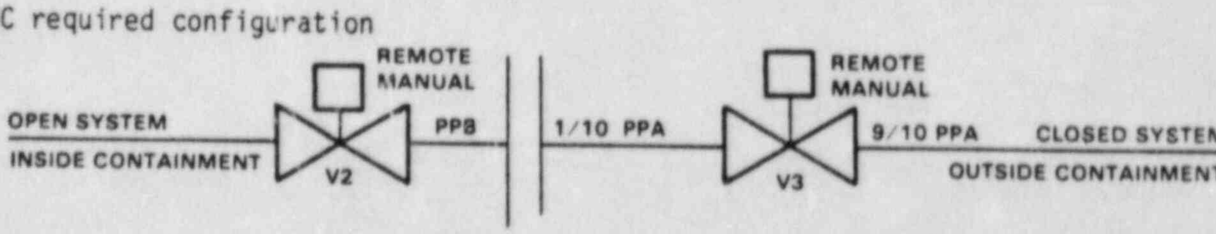
Case V:

Applies to penetration #H-28 (two identical lines).

Present configuration



GDC required configuration



The boolean equations which describe the unavailabilities of these penetrations are as follows:

Before: PPA

After: (V2+PPB) * [1/10 PPA+(V3 * 9/10 PPA)]

Using the failure rates presented in Table VI-4-2, the following unavailabilities were calculated.

Case V before: 2.2E-7

Case V after: (1E-1 + 2.2E-7) * (2.2E-8 + (1E-1 * 2E-7))
4.2E-9

6. Conclusions

The results of this analysis are presented in Table VI-4-3. As previously stated, the actual unavailabilities given are for comparison purposes only. Using them as such, it can be seen that a small reduction in the unavailabilities of most of the examined penetrations can be achieved by conforming them to the GDC. However, the leakage probability for this plant as calculated in the Big Rock Point PRA is approximately 0.1. A reduction in the failure to isolate probabilities for the penetrations would not significantly affect this value since failure to isolate penetrations in their present configurations would contribute only approximately 1E-3 to the leakage probability. We therefore rate this issue to be of low risk significance.

TABLE VI-4-1

Penetration #	Deficiency
H-36	A
H-27	A
H-113	B
H-28	A
H-14	B
H-13	B
H-12	B
H-9	B
H-11	C

NOTES:

A. Valve type: deviates by using a local manual valve as an isolation valve.

B. Valve number: deviates by having no isolation valve outside containment.

C. Check valve usage: deviates by using a check valve as an isolation valve outside containment.

TABLE VI-4-2 Fault Summary

Event Name	SubEvent Description	Failure Rate*	Fault Exposure Time	SubEvent Unavailability	Total Unavailability
PPA	Pipe Rupture	1E-10/hr	2190 hrs.		2.2E-7
PPB	Pipe Rupture	1E-10/hr	2190 hrs.		2.2E-7
CV1	Internal leakage	3E-7/hr	2190 hrs.	6.6E-4	
(check valve)	Rupture	1E-8/hr	2190 hrs.	2.2E-5	6.8E-4
V1	Fails to close	1E-3/demand		1E-3	
(MOV,NOFO, auto close)	Rupture	1E-8/hr	2190 hrs.	2.2E-5	1E-3
V2	Fails to close	1E-3/demand		2E-3	
(MOV,NOFO,	Rupture	1E-8/hr	2190 hrs.	2.2E-5	
manual close)	Operator fails to act	1E-1/demand		1E-1	1E-1
CV2	Internal leakage	3E-7/hr	2190 hrs.	6.6E-4	
(check valve)	Rupture	1E-8/hr	2190 hrs.	2.2E-5	6.8E-4
HX1 (heat exchanger)	Rupture	1E-9/hr	2190 hrs.		2.2E-6
NV1 (AOV,NOFO)	Rupture	1E-9/hr	2190 hrs.		2.2E-6
NV2 (AOV,NOFO)	Rupture	1E-9/hr	2190 hrs.		2.2E-6

TABLE VI-4-2 Fault Summary (continued)

Event Name	SubEvent Description	Failure Rate*	Fault Exposure Time	SubEvent Unavailability	Total Unavailability
V3	Fails to close	1E-3/demand		1E-3	
MOV,NOFO	Rupture	1E-8/hr	2190 hrs	2.2E-5	
manual close)	Operator fails to act	1E-1/demand		1E-1	1E-1

*From WASH-1400 Table III-4-1 and Table III-6-1.

NOTES:

Demand probabilities are based on presence of proper input control signals.

Auto isolation valves are assumed to move to position of greater safety on loss of power.

Fault exposure time based on semi-annually checking of valves

TABLE VI-4-3

Results

Penetration #	Unavailability Present Configuration	Unavailability GDC Required
H-27	6.8E-4	6.8E-7
H-36	6.8E-4	6.8E-7
H-113	1.5E-10	2.8E-11
H-11	9.3E-10	6.8E-7
H-9	2.2E-7	2.2E-10
H-12	2.2E-7	2.2E-10
H-13	2.2E-7	2.2E-10
H-14	2.2E-7	2.2E-10
H-28	2.2E-7	4.2E-9

VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response Time Testing

1. NRC Evaluation

Tests of the reactor protection system (RPS) should be conducted periodically and should check redundant channels independently to determine if any losses of redundancy have occurred. These tests should duplicate, as closely as possible, actual operating conditions. Also, where required, response time testing should be included as part of the test program.

The NRC evaluation found that the Big Rock Point test program does not meet all of the requirements of the current licensing criteria. There are 5 areas of nonconformance with current criteria. The Big Rock Point Technical Specifications do not require calibration of the initiation channels for the RPS, the Emergency Condenser System and the Containment Isolation System. (Calibration procedures are utilized in the plant test procedures.) Response time testing of the RPS and the engineered safety features (ESF) systems are not required by plant Technical Specifications. (The test procedures in use at the plant do include provisions for response time testing.) The response time tests that are performed do not include provisions for response time testing of the sensors that initiate RPS or ESF action. At present there are no channel checks required by Big Rock Point Technical Specifications. (Other than the devices for which channel checks are not suitable, blind bistable devices, procedures require periodic checks.) The last item of nonconformance is that channel functional tests are performed at refueling rather than monthly as required by STS.

2. NRC Recommendation

The licensee should implement a program for response time testing of the neutron monitoring channels that provide input to the reactor protection system. The response time test requirements should be incorporated into the plant Technical Specifications.

The procedures used for instrument calibration are not included in the Technical Specification requirements for Big Rock Point. The need to include the required instrument calibration in the Technical Specifications, as well as the plant procedures, will be evaluated in the integrated assessment.

3. Systems Affected

The systems affected by this issue are the RPS and the ESF system.

4. Comments

The important aspect of response time testing to be considered when assessing its impact on risk is the relatively short time period involved in the response time test. The time period involved in response time testing is usually on the order of a few seconds. When a risk analysis is performed the response time of a system is much longer than a few seconds (based on analyses performed for many PRA studies). Initial operation of the system in periods longer than that tested in a response time test would be sufficient to guarantee system success in response to an initiating event.

The operability tests performed on the RPS will determine whether the system is functioning or not. For a risk analysis the information from this type of test is sufficient to determine the system reliability. No additional information is gathered from the response time testing. Since response time testing would provide no additional information required in a risk analysis the lack of response time testing would not affect the results of a risk analysis.

The plant Technical Specifications do not contain the requirements for instrument calibration. However, the calibration is performed according to plant procedue. A risk analysis would use the information that most closely represents the plant as it is now. In this case that implies the use of the plant procedures. Since the information from the plant procedures is used in the risk analysis the incorporation of calibration requirements in the plant Technical Specifications would have no effect on the results of a risk analysis.

5. Analysis

No further analysis is required for this issue.

6. Conclusion

Response time testing does not add any required information used in a risk analysis provided functional testing is performed. The incorporation of present plant conditions (i.e., the calibration procedures in use) in the plant Technical Specifications would not affect the results of a risk assessment. For these reasons we rate this issue to be of low risk significance.

VII-1.A Isolation of Reactor Protection System From Non-Safety Systems, Including Qualification of Isolating Devices

1. NRC Evaluation

The reactor protection system (RPS) comp`ies with all current criteria and review guidelines except for the isolatio of the power supplies for the RPS channels. They do not meet the single failure criterion. The staff feels the under and over voltage protection are inadequate for the following reasons.

1. The licensee has failed to show that the set points of the existing protection are within the qualification of the scram solenoids.
2. The failure of the existing protective relaying or breaker in either motor generator set coincident with a regulator or bearing failure may lead to a failure to scram.
3. A regulator or bearing failure is an event which must be mitigated by equipment satisfying the single failure criterion.
4. There is no protection for under frequency events. These events can result from bearing failures.

2. NRC Recommendation

The RPS is adequately isolated with the possible exception of the effects from the motor generator sets. Suitably qualified isolators should be provided to protect the RPS from voltage regulation failures and frequency degradation due to motor generator set abnormal operation (i.e., erratic output).

3. Systems Affected

The only system affected by this issue is the RPS.

4. Comments

Qualification of the isolation devices will not be considered in this analysis. The assumption is made that the isolators currently installed at the Big Rock Point plant will not adequately protect the RPS given a motor generator fault (erratic output). This assumption is made based on the first and fourth items listed under the heading NRC Evaluation. These items imply that the current isolation devices do not adequately protect the RPS circuitry.

There are two motor generator sets associated with the RPS circuitry. A fault affecting the output of either one of the motor generator sets would fail the RPS. The fault must produce an erratic output to affect the RPS. Any fault that eliminates the motor generator set output would not fail any part of the RPS.

5. Analysis

The failure of interest is a degraded output from either of the motor generator sets. High voltage, low voltage and frequency degradation could affect portions of the RPS and prevent a scram. The assumption is made that the current isolation devices on the Big Rock Point RPS will not adequately protect the RPS from degraded motor generator set outputs.

From IEEE STD 500 the failure rate for a motor generator, for the failure mode - degraded output, is 3E-7/hr. It is assumed that degraded motor generator output faults would not be detected until the monthly test of the RPS instrumentation. With a monthly test interval and the failure rate for degraded motor generator output, the probability of degraded motor generator output can be calculated from:

$$1/2\lambda t$$

where

λ = failure rate = 3E-7/hr
t = test interval = 720 hrs.

From this the probability for the degraded output from one motor generator set is 1.1E-4. With the assumptions made for this analysis the degraded output of the motor generator will fail the RPS. Since either of the two motor generator sets could fail the RPS the probability of RPS failure due to degraded motor generator set output is approximately 2.2E-4.

In the Big Rock Point PRA the failure probability used for the RPS was 3.5E-5. This was based on common mode mechanical faults preventing insertion of the control rods. Combining these two figures the failure probability of the RPS becomes 2.6E-4.

Thirteen dominant ATWS sequences were identified in the Big Rock Point PRA. These are the only sequences that would be affected by this issue. Their total frequency was given as 2.7E-5/yr. If the PRA value of 3.5E-5 for RPS failure is replaced by the 2.6E-4 calculated here, the ATWS core melt frequency increases to approximately 2E-4/yr, an increase of approximately 1.7E-4/yr. This would increase the core melt probability from 9.75E-4/yr, as calculated in the Big Rock Point PRA, to 1.2E-3/yr.

If adequate isolators are provided between the motor generator sets and the RPS, the isolators would have to fail in order for the degraded motor generator output to affect the RPS. Assuming a 1E-3 per demand failure probability for the isolator, the probability of one motor generator set failing and affecting the RPS is

$$(1.1E-4)\ (1E-3) = 1E-7.$$

The degraded output from a motor generator set with adequate isolation would no longer significantly affect the RPS failure probability.

6. Conclusion

The analysis performed here assumed that all degraded faults of either motor generator set will affect, and fail, the RPS. It was also assumed that the erratic output from the motor generator set would not be detected until the RPS is tested. Both assumptions are very conservative. However, the results of this analysis show that with these assumptions the failure of an unisolated motor generator set is a significant contributor to the RPS failure probability. This type of RPS failure would contribute 1.7E-4/yr to the Big Rock Point core melt frequency. This is a significant fraction of the total core melt frequency of 9.75E-4/yr for this plant. Due to the size of the contribution of the motor generator set failure to the expected core melt frequency and the conservatism of the analysis, we rate this issue to be of medium risk significance.

VII-3 Systems Required For Safe Shutdown

1. NRC Evaluation

Systems required to bring the Big Rock Point Nuclear Power Plant from hot shutdown to cold shutdown with only offsite or onsite power available and a single failure meet the current NRC criteria. However, the vital indications in the control room such as reactor pressure, temperature and level indicators can be lost given a single failure.

2. NRC Recommendations

The initial recommendation of the NRC staff was that a design modification should be incorporated in the Big Rock Point Nuclear Power Plant such that independent and redundant indication of the process variables that are vital for the safe shutdown of the reactor are available in the control room. This is the requirement analyzed below. Subsequent to the analysis the staff decided that no changes to present instrumentation should be made until the Reg. Guide 1.97 backfit for this Big Rock Point issue is resolved.

3. Systems Affected

Vital control room indicators and the operator actions for safe shutdown of the plant are affected by this issue.

4. Comments

None

5. Analysis

Figure VII-3-1 shows a simplified diagram of the electrical power system at the Big Rock Point plant. The panels that provide power to the vital instrumentation are panels 1Y and 2Y. During normal operation the automatic transfer bus is connected to point A and receives power from 480V Bus 1A. Upon loss of this bus the automatic transfer bus will switch to contact B and receives power from 480V Bus 2B. The biggest contributor to the loss of 480V Bus 1A is the loss of offsite power. This is due to the fact that the frequency of loss of power, 0.13/year, is much higher than the failure probability of transformers or circuit breakers. Thus, given a loss of offsite power, if the automatic bus transfer fails there would be no power available to the panels. But this failure is dominated by the failure of the emergency diesel power to supply power to 480V Bus 2B since the failure probability of the diesel generator, at 0.018/demand, is much higher than the failure probability of the automatic transfer bus, 1.2×10^{-3}/demand given annual testing. The utility in its PRA did not take credit for the use of the backup diesel generator within the first three and a half hours following an accident sequence initiator. That assumption will be used in this analysis. Even after loss of power to the vital instrumentation panels 1Y and 2Y the plant can be shutdown and cooldown can proceed for at least four hours. This is due to the fact that the emergency condenser has sufficient inventory to cool the reactor for four hours and the only normally closed valves in this system are <u>DC</u> powered and have control room indication. Thus, given a total loss of AC power, as long as DC power is available the plant can be shutdown and cooled down for at least four hours through use of the shutdown condenser which requires only DC power to operate for this length of time. This offers a reasonable period of time to try to recover either offsite power or the onsite emergency power. (The probability of not recovering offsite power within three and a half hours was estimated to be .15 in the Big Rock Point PRA.)

6. Conclusions

There are two facts that are relevant to this issue. First, in the current Big Rock Point design there is only one dedicated diesel connected to the 480V emergency bus. Given a total loss of AC power which implies loss of vital instrumentation in the control room, the plant can be shutdown and cooled down for at least four hours. Second, a failure that would affect only the shutdown panel does not affect the operability of the safety systems required to shut down Big Rock Point.

Based on these facts addition of a redundant vital instrumentation panel does not seem to offer much in the way of reduction of risk due to operation of this plant. Consequently, the risk significance of this issue is ranked low.

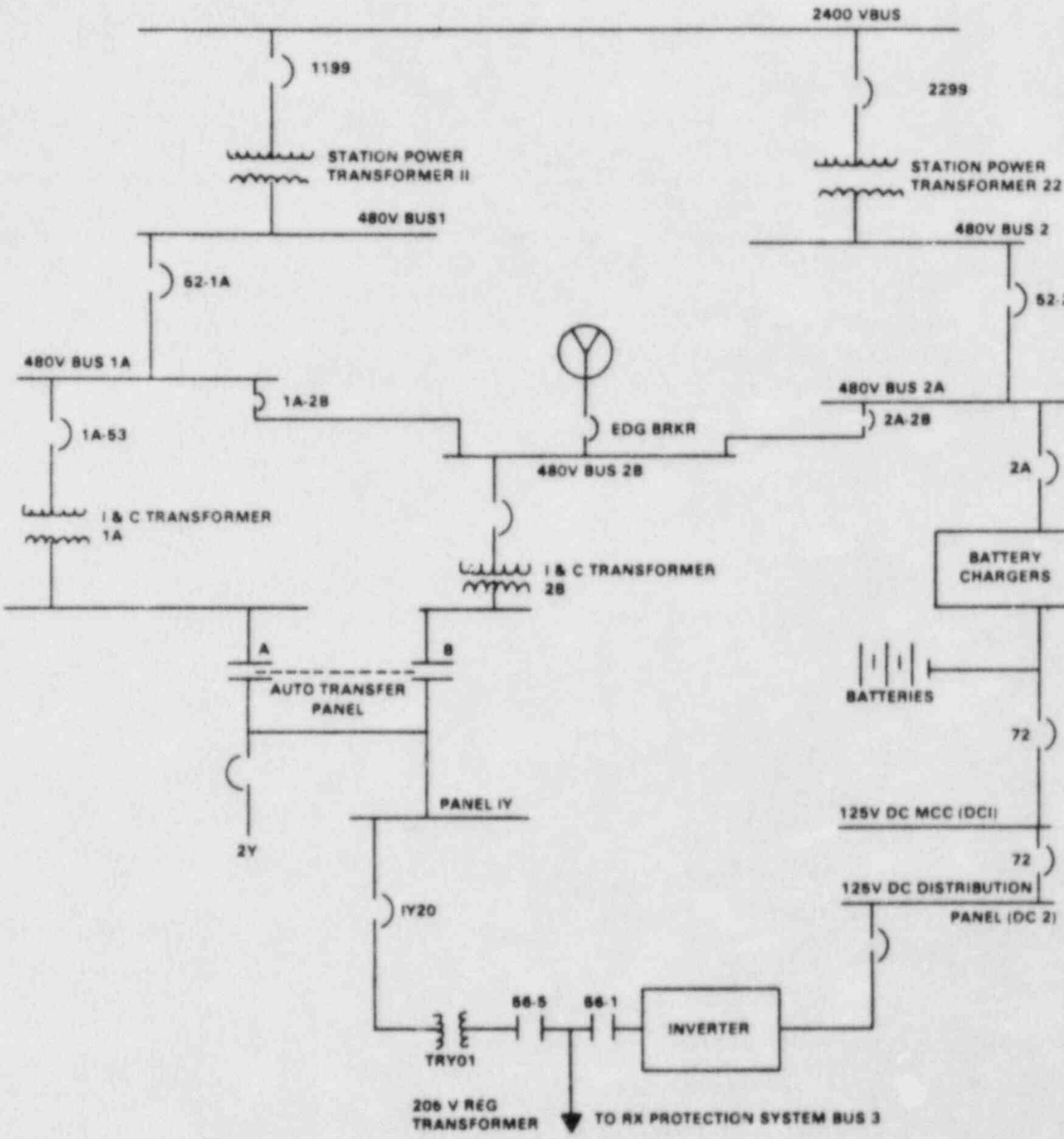


Figure VIII-3-1. SIMPLIFIED ELECTRICAL POWER SYSTEM AT BIG ROCK POINT

VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

1. NRC Evaluation

The Big Rock Point control room has no indication of DC bus voltage, battery current, battery charger current or breaker/fuse status. These indications are required so that the operator can prevent the loss of an emergency DC bus or take timely corrective action in the event of the loss of an emergency DC bus.

2. NRC Recommendation

As a minimum the following additional indications and alarms of the Class IE DC power systems' status should be provided in the control room:

Battery current (ammeter charge/discharge)
Battery charger output current (ammeter)
DC bus ground alarm
Battery breaker or fuse open alarm
Battery charger output breaker or fuse open alarm
DC bus voltage

3. Systems Affected

The only systems directly affected by this issue are the JC power systems. Indirectly this issue affects several systems including the reactor depressurization system, fire protection system (core spray system), the emergency condenser, and the post incident system.

4. Comments

There are seven class IE DC power supplies at Big Rock Point. They are the 125V DC system, comprised of one battery and two chargers; a diesel generator battery and charger; a diesel fire pump battery and charger; and 4 Uninterruptable Power Supplies (UPS), each comprised of a battery and charger. Of these seven DC systems only the 125V DC system supplies power to multiple non-related loads. The diesel generator and diesel fire pump batteries and chargers supply power only to the diesel generator and the fire pump respectively. Each of the 4 UPS supplies power to one of the 4 reactor depressurization system channels. UPS channel A is also used to provide power necessary to start and load the emergency diesel generator.

Improved annunciation of the status of DC buses will reduce the expected unavailabilities of these buses by reducing the fault exposure time for the bus or battery failures. There are two types of battery faults that must be considered when evaluating the fault exposure time for battery faults. Detectable battery faults can be discovered through the use of annunciated conditions. Nondetectable battery faults will go undetected, no matter what conditions are annunciated. One of the results of NUREG-0666, "A Probabilistic Safety Analysis of DC Power Supply Requirements for Nuclear Power Plants", is that approximately one half of the battery faults, as reported in LERs, are detected at battery tests. The improved annunciation recommended for the Big Rock Point plant cannot be expected to improve upon this ratio. In the analysis it is assumed that with the present annunciation all battery faults are detected at battery tests.

5. Analysis

The four sets of batteries, the 125V station battery system, the 4 UPS batteries, the diesel fire pump battery system, and the diesel generator battery system, will be analyzed individually since they are essentially independent of each other.

The diesel generator battery system consists of the battery and a battery charger. There is no breaker or fuse between the battery and the diesel generator. Presently the diesel generator is tested every three days. This test verifies the operability of the battery charger. Battery tests are conducted at monthly intervals.[1] Table VIII-3.B-1 lists the data for this battery system with the annunciators currently at Big Rock Point and with the proposed annunciation capabilities. Battery faults are not included (as a separate fault) in the Big Rock Point PRA. Therefore, a simple fault tree for failure of this battery to supply power to the diesel generator was produced. This fault tree is shown in Figure VIII-3.B-1.

Using this fault tree and the data of Table VIII-3.B-1 the battery system failure probability for the system as it is now is 4E-4 for accident sequences initiated by a loss of offsite power and ϵ, i.e., negligible, for all other sequences. With the proposed modification to the DC annunciators the failure probability is reduced to 2E-4 for the loss of offsite power sequences. This is a reduction of the battery system failure probability by a factor of 0.5. The diesel generator failure to start probability used in the Big Rock PRA [illegible] 9E-2. A reduction in the diesel generator failure rate of 2E-4 is only a 1% reduction in the failure probability. This small a reduction is not significant.

The diesel fire pump DC system is required for the diesel fire pump only. The battery charger is tested during the diesel fire pump test, conducted weekly. The batteries are tested monthly. (As with the diesel generator, more frequent tests are performed but the longer test interval is used in this analysis.) There is no breaker or fuse between the battery and the diesel fire pump. Table VIII-3.B-2 contains the data used in this analysis for both cases, i.e., for the present annunciation and for the proposed modifications in the system annunciation. The fault tree for loss of DC power to the diesel fire pump is identical to that for loss of DC power to the diesel generator, Figure VIII-3.B-1.

Using the data of Table VIII-3.B-2 the failure probability of the diesel fire pump battery system is:

1 More frequent tests are performed; however, this is the longest interval for any type of test and the monthly test is used conservatively.

present annunciation - LOSP accident sequence - 4E-5,
present annunciation - all other accident sequences - ~1E-7,
modified annunciation - LOSP accident initiator - 2E-5,
modified annunciation - all other accident initiators - ε.

The reduction gained with the modified annunciation is 2E-5 for a LOSP initiated accident sequence and orders of magnitude less for all other accident sequences. The Big Rock Point PRA used a failure probability of 3.1E-3 for the failure of the diesel driven fire pump to start. The reduction in the failure probability of the battery system is less than 1% of the diesel fire pump failure probability. This reduction will have no significant effect on the diesel fire pump availability.

Three of the UPS batteries supply power to one RDS channel only. The fourth UPS battery (battery A) supplies power to one RDS channel and to the control logic for the emergency diesel generator. This difference is unimportant in the accident sequences that do not involve a loss of offsite power. Each UPS battery is tested monthly. A simplified fault tree for each UPS battery system is shown in Figure VIII-3.B-2. This is adapted from the Big Rock Point UPS fault tree, to facilitate the use of the methodology used in this analysis. The data for this fault tree is given in Table VIII-3.B-3.

The failure probability for each UPS with the annunciators present at Big Rock Point for any plant condition except a loss of offsite power is approximately 2E-6. Modifications to the annunciation system at Big Rock Point could not reduce this below 1E-6. The failure probability for a reactor depressurization system (RDS) train (each one supplied by one UPS) as used in the Big Rock Point PRA was 8.6E-3. The battery system failures do not significantly contribute to the RDS train failure probability.

For the accident sequences that are initiated by a loss of offsite power the failure probabilities for the UPS trains are:

UPS A present annunciation	- 7.1E-4
UPS B,C,D present annunciation	- 7.1E-5
UPS A modified annunciation	- 2.1E-4
UPS B,C,D modified annunciation	- 2.1E-5

The reduction of the battery system, UPS, train is 5E-4 (UPS A) and 5E-5 (UPS B,C,D). This could affect the failure probability of each RDS train. If this reduction due to improved annunciation is added to the RDS train failure probability of 8.6E-3 the effect of the improved annunciation system can be calculated. The Big Rock Point PRA calculated the RDS failure probability using the following equation:

$$RDS = RF_{RDS} + CC_{RDS} + CC_{pumps}$$

where

> RDS = RDS failure probability
>
> RF_{RDS} = probability of random failures of the RDS trains causing failure of 2 RDS trains (6 possible combinations of train failures: AB,AC,AD,BC,BD,CD)
>
> CC_{RDS} = common cause failure probability, set equal to 0.1 of an RDS train failure
>
> CC_{pumps} = the common cause failure probability of the fire protection system pumps.

For an LOSP condition the following values were used in the equation above.

$$RF_{RDS} = 6[(\text{probability of 1 RDS train failure})(.9)]^2 = 3.6E\text{-}4^{(1)}$$
$$CC_{RDS} = .1(8.6E\text{-}3) = 8.6E\text{-}4$$
$$CC_{pumps} = 1.8E\text{-}3$$
$$RDS = 3.0E\text{-}3$$

Adding the reduction gained through improved annunciation (5E-4 for UPS train A) the failure probability for one RDS train becomes 9.1E-3. (For conservatism the effect of improved annunciation on UPS A will be used for all four UPS trains.) Using this value the failure probability of the RDS becomes

$$RDS = RF_{RDS} + CC_{RDS} + CC_{pumps}$$
$$RDS = [.9(9.1E\text{-}3)]^2 \cdot 6 + .1(9.1E\text{-}3) + 1.8E\text{-}3$$
$$= 4.0E\text{-}4 + 9.1E\text{-}4 + 1.8E\text{-}3$$
$$= 3.1E\text{-}3$$

The change in the RDS failure probability (for LOSP accident sequences only) is 1E-4 which would be approximately a 3% reduction in the system failure probability. If this reduction is applied to all of the dominant LOSP sequences involving RDS/CS failure, which contribute 4.7E-5/yr to the core melt frequency of 9.75E-4, the reduction in core melt frequency is approximately 1E-6/yr. This is less than a 1% reduction of the total core melt frequency.

The 125V DC system supplies power to the post incident system, the enclosure spray system, the emergency condenser, the primary isolation system, the main condenser and the liquid poison system. A loss of DC power will fail all of these systems. Additionally, failure of the 125V DC system will degrade the operation of the fire protection system, the condensate system and the containment vent valves.

The 125V DC system has the required bus voltage and ground alarm indication but does not have the required battery charger current, battery

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1 The .9 factor accounts for the 10% of the failure probability assumed to be due to common cause failures.

current or breaker status alarms. Using the simplified fault tree of Figure VIII-3.B-3 and the data from Table VIII-3.B-4 the change in the battery unavailability due to improved annunciation was calculated. It is assumed that with the present annunciators no battery faults are detected until the battery service tests, conducted approximately yearly. The probability of a loss of DC power at the 125V bus is calculated to be

4.4E-3 - present annunciation system and LOSP
9E-5 - present annunciation system and no LOSP
2.2E-3 - modified annunciation system and LOSP
~1E-6 - modified annunciation system and no LOSP

The dominant accident sequences, as found in the Big Rock Point PRA, where a DC failure could affect the sequence frequency were determined. Sequences were eliminated from consideration if they met one of the two following criteria. Either no systems that would fail on a loss of DC power failed in the accident sequence or any one of the systems that a DC power failure would fail was required to succeed in the accident sequence. If the 125V DC power system did not affect any failed system in an accident sequence a change in the DC system unavailability would not affect the sequence frequency. If any system that failure of the DC system would fail is required not to fail then the DC system could not have failed and the unavailability change will not affect the sequence frequency.

Using these criteria all but 29 of the Big Rock Point PRA dominant accident sequences were eliminated. These sequences and their frequency, as calculated in the Big Rock Point PRA are given in Table VIII-3.B-5.

The contribution of DC system failures to the ATWS sequences (sequences 13-25) is negligible. The failure probability for the RPS (from the Big Rock Point PRA) is 3.5E-5. For each sequence the combination of the initiating event, RPS failure and DC power failure has a frequency of less than 1E-8 or the system the DC power failure would affect is assumed to fail with a probability of 1. The liquid poison system is assumed to fail with a probability of 1 in sequences 15, 16, 19, 20, 22, 23, and 24.

Similarly, for the LOCA sequences (5-7) and sequence 28 the combination of initiator frequency and DC power failure probabilities is less than 1E-8/yr.

The analysis to determine the contribution of DC system failures to each of the remaining sequences follow. All failure probabilities except for the battery failure are taken from the Big Rock Point PRA. The results are presented in Table VIII-3.B-5.

PIF_SYL

The loss of DC power affects events I and L. L for this sequence consists of the PIS only. In this sequence offsite power is restored before the PIS is required and therefore 9E-5 is used as the failure probability of the DC power supply with the present annunciation system, and 1E-6 is used for the modified system.

$P = .13/yr$
$F_s = .2$
$Y = .1$
$IL = 9E\text{-}5$ (as is annunciation)
$1E\text{-}6$ (modified annunciation)

The sequence frequency due to cut sets with battery faults is 2.3E-7/yr with the present annunciation and 2E-9/yr with the modified annunciation.

PIF_sYC

Loss of DC power affects events I and C. Loss of DC power alone will not fail the core spray system (event C). The AC injection valves must also fail. The failure probability used for the AC valve failure would be the valve failure probabilities plus the probability that the operator will not load the valves onto the emergency generator. This value is 2.6E-2 plus 1E-2 or 3.6E-2.

$P = .13/yr$
$F_s = .2$
$Y = .1$
$IC = (3.6E\text{-}2)(4.4E\text{-}3) = 1.6E\text{-}4$ (battery system failure as is annunciation)
$(3.6E\text{-}2)(2.2E\text{-}3) = 8E\text{-}5$ (battery system failure modified annunciation)

The sequence frequency due to cut sets containing battery faults is 4E-7/yr (as is annunciation) or 2E-7/yr (modified annunciation).

$PQIF_sL$

The analysis is identical to that for sequence PIF_sYL.

$P = .13/yr$
$F_s = .2$
$Q = .018$
$IL = 9E\text{-}5$ (battery system failure - as is annunciation)
$1E\text{-}6$ (battery system failure - modified annunciation)

The sequence frequency due to cut sets containing battery faults is 4.2E-8/yr with the present annunciation, 4.7E-10/yr with modified annunciation.

$PQIF_sC$

Loss of DC power affects events I and C. Loss of DC power does not normally fail the core spray system completely. It must be combined with the failure of the AC core spray valves. However, since this is a loss of offsite power sequence and the emergency diesel generator has failed (event Q) the loss of the batteries will fail the core spray system.

$P = .13/yr$
$F_s = .2$
$Q = .018$
$IC = 4.4E\text{-}3$ (battery system failure as is annunciation)
$2.2E\text{-}3$ (battery system failure modified annunciation)

The sequence frequency due to cut sets with battery faults is 2.1E-6/yr with the present annunciation and 1E-6/yr with the modified annunciation.

WE_vL

The event L is a combination of the failure of the PIS, the emergency condenser and the shutdown cooling system. Loss of DC station power will fail the emergency condenser and the PIS. The failure probability for the shutdown cooling system is 3.1E-2.

$W = .06$
$E_vL = (3.1E\text{-}2)(9E\text{-}5) = 3E\text{-}6$ (battery system faults as is annunciation)
$(3.1E\text{-}2)(1E\text{-}6) = 3E\text{-}8$ (battery system faults modified annunciation)

The sequence frequency due to cut sets containing battery faults is 1.8E-7/yr (present annunciation) or 2E-9 (modified annunciation).

WE_vC

The failure of the emergency condenser valves and the core spray DC valves are affected by the DC system failures. The core spray AC valves must also fail to fail the core spray system. The failure probability for the AC core spray valves is 2.6E-2.

$W = .06$
$E_vC = 9E\text{-}5\ (2.6E\text{-}2) = 2.3E\text{-}6$ (battery system faults as is annunciation)
$1E\text{-}6\ (2.6E\text{-}2) = 2.6E\text{-}8$ (battery system faults modified annunciation)

The sequence frequency due to cut sets containing battery faults is 1.4E-7/yr (present annunciation) or 1E-9/yr (modified annunciation).

BB_cZY_fL

For this sequence long term cooling consists of the PIS, the shutdown cooling system and the emergency condenser. Loss of DC power will fail the MSIVs, the PIS, and the emergency condenser. The shutdown cooling system has a failure probability (for this sequence) of 3.1E-2.

$B = .1$
$B_c = .38$
$Y_f = 1.0$
$ZL = (3.1E\text{-}2)(9E\text{-}5) = 2.8E\text{-}6$ (battery system failure as is annunciation)
$(3.1E\text{-}2)(1E\text{-}6) = 3.1E\text{-}8$ (battery system failure modified annunciation)

The sequence frequency due to cut sets containing battery faults is 1.2E-7/yr (present annunciation) or 1E-9/yr (modified annunciation).

BB_CZY_fC

As in sequence WE_vC the AC core spray valves must fail in conjunction with a DC power system failure to fail the core spray system. In combination with the AC valve failures (probability = 2.6E-2) the DC system failures will fail both C and Z.

B = .1
B_C = .38
Y_f = 1.0
ZC = (2.6E-2)(9E-5) = 2.3E-6 (battery faults as is annunciation)
(2.6E-2)(1E-6) = 2.6E-6 (battery faults modified annunciation)

The frequency of this sequence due to cut sets containing battery faults is 9E-8/yr (as is annunciation) or 9E-10/yr (modified annunciation).

RR_OL

For this sequence only L is affected by the loss of DC power. The event L includes failure of the emergency condenser, the PIS, and the shutdown cooling system which is independent of DC power and has a failure probability of 3.1E-2.

R = 1.2E-3
R_O = 1.0
L = (3.1E-2)(9E-5) = 2.8E-6 (battery system failure as is annunciation)
(3.1E-2)(1E-6)=3.1E-8(battery system failure modified annunciation)

The frequency for this sequence due to cut sets containing battery system faults is less than 1E-8/yr.

RR_OC

The event C is the same as in previous sequences and requires a combination of AC valve failures and DC system failures to fail.

R = 1.2E-3
R_O = 1.0
C = (2.6E-2)(9E-5) = 2.3E-6 (battery failure as is annunciation)
(2.6E-2)(1E-6) = 2.6E-8 (battery failure modified annunciation)

The sequence frquency due to cut sets containing battery system faults is less than 1E-8/yr.

WE_vKC

In this sequence the event C will occur with a probability of 1.0. Therefore, the failure of the DC system will affect only event E_V.

$W = .06/yr$
ξ_v = 9E-5 (DC system faults as is annunciation)
1E-6 (DC system faults modified annunciation)
$K = .062$
$C = 1.0$

The sequence frequency due to cut sets containing battery system faults is 3E-7/yr (present annunciation) or 4E-9/yr (modified annunciation).

The reduction in the core melt frequency due to the proposed modification of the 125V DC annunciation system is shown in Table VIII-3.B-5. The total reduction is approximately 2.3E-6/yr. This is less than a 1% reduction of the expected core melt frquency of 9.75E-4/yr.

6. Conclusion

The proposed modifications to the Big Rock Point DC power systems control room annunciation has only a minimal effect on the expected core melt frequency of the Big Rock Point plant. The modification of the diesel generator battery system has virtually no effect on the diesel generator (the emergency AC power system) unavailability. The diesel fire pump battery system annunciation modifications have almost no effect on the fire pump unavailability. Modifications to the UPS annunciation has a very small effect on the RDS unavailability but does not significantly affect the core melt frequency. Finally, the 125V DC station battery system unavailability is reduced by a factor of 2 but again this does not greatly affect the core melt frequency. The annunciator modifications to this system reduce the core melt frequency by less than 1%. Due to the above reasons we rate this issue to be of low risk significance.

Table VIII-3.B-1 Data Summary - DG Battery System

	Failure Rate	Fault Exposure Time	Unavailability
Battery Charger - local faults			
"as is"	2.8E-6/hr	36hrs	9E-5
"mod"	2.8E-6/hr	20hrs	6E-5
Battery Charger Breaker - fails open			
"as is"	1E-6/hr	36hrs	4E-5
"mod"	1E-6/hr	20hrs	2E-5
NonDetectable Battery Faults			
"as is"	1E-6/hr	360hrs	4E-4
"mod"	0.5E-6/hr	360hrs	2E-4
Detectable Battery Faults			
"as is"	-	-	0.0
"mod"	0.5E-6/hr	20hrs	1E-5
No AC to Battery Charger			
o Loss of Offsite Power			1.0
o All other conditions			$\sim 10^{-6}$

Table VIII-3.B-2 Data Summary - Diesel Fire Pump Battery System

	Failure Rate	Fault Exposure Time	Unavailability
Battery Charger - local faults			
"as is"	2.8E-6/hr	82hrs	2E-4
"mod"	2.8E-6/hr	20hrs	6E-5
Battery Charger Breaker - fails open			
"as is"	1E-6/hr	82hrs	8E-5
"mod"	1E-6/hr	20hrs	2E-5
NonDetectable Battery Faults			
"as is"	1E-6/hr	360hrs	4E-4
"mod"	0.5E-6/hr	360hrs	2E-4
Detectable Battery Faults			
"as is"	-	-	0.0
"mod"	0.5E-6/hr	20hrs	1E-5
No AC to Battery Charger			
o Loss of Offsite Power(1)			1.0
o All other conditions			<1E-6

(1) dominated by failure of emergency AC power: 0.1 is Big Rock Point PRA emergency AC failure probability given a 4 hour demand

Table VIII-3.B-3 Data Summary - UPS

	Failure Rate	Fault Exposure Time	Unavailability
Battery Charger - local faults			
"as is"	2.8E-6/hr	360hrs	1E-3
"mod"	2.8E-6/hr	20hrs	6E-5
Battery Charger Breaker - fails open			
"as is"	1E-6/hr	20hrs	2E-5
"mod"	1E-6/hr	20hrs	2E-5
Battery Breaker - fails open			
"as is"	1E-6/hr	360hrs	4E-4
'mod"	1E-6/hr	20hrs	2E-5
NonDetectable Battery Faults			
"as is"	1E-6/hr	360hrs	4E-4
"mod"	0.5E-6/hr	360hrs	2E-4
Detectable Battery Faults			
"as is"	-	-	0.0
"mod"	0.5E-6/hr	20hrs	1E-6
Distribution Panel Faults			~1E-6
No AC to Battery Charger			
o UPS A - LOSP			1.0
o UPS A - Non-LOSP			~1E-6
o UPS B,C,D - LOSP			0.1
o UPS B,C,D - Non-LOSP			~1E-6

Table VIII-3.B-4 Data Summary - 125V DC System

	Failure Rate	Fault Exposure Time	Unavailability
Battery Charger - local faults			
"as is"	2.8E-6/hr	8760hrs	1.2E-2
"mod"	2.8E-6/hr	20hrs	6E-5
Battery Charger Breaker - fails open			
"as is"	1E-6/hr	8760hrs	9E-3
"mod"	1E-6/hr	20hrs	2E-5
NonDetectable Battery Faults			
"as is"	1E-6/hr	8760hrs	4.4E-3
"mod"	0.5E-6/hr	8760hrs	2.2E-3
Detectable Battery Faults			
"as is"	-	-	0.0
"mod"	0.5E-6/hr	20hrs	1E-5
DC Bus Faults			1E-6
DC Bus - Maintenance Unavailability			1E-7
Loss of AC Power to Charger			
o LOSP			1.0
o All other conditions			~1E-6

Table VIII-3.B-5 Effect of DC Power System Failure on Core Melt Frequency

	Sequence Frequency (yr-1)	DC system failure contribution: Present Annunciation (yr-1)	Modified Annunciation (yr-1)	Reduction (yr-1)
1 PIF_sYL	9.9E-7	2.3E-7	2E-9	2.3E-7
2 PIF_sYC	8.5E-7	4E-7	2E-7	2E-7
3 $PQIF_sL$	1.8E-7	*		
4 $PQIF_sC$	1.5E-7	2.1E-6	1E-6	1E-6
5 S_2L	3.7E-6	*		
6 S_2C	4.0E-7	*		
7 S_7L	3.7E-7	*		
8 S_4C	1.0E-4	*		
9 WE_vL	1.7E-6	1.8E-7	2E-9	1.8E-7
10 WE_vC	6.7E-7	1.4E-7	1E-9	1.4E-7
11 BB_cZY_fL	4.9E-5	1.2E-7	1E-9	1.2E-7
12 BB_cZY_fC	2.0E-5	1E-7	9E-10	9E-8
13 $T_1AY_fL_r$	1.4E-6	*		
14 $T_1AY_fOL_r$	4.2E-7	*		
15 $T_1AB_oL_r$	8.8E-7	*		
16 $T_2AB_oL_r$	3.2E-6	*		
17 $T_3AY_fL_r$	1.2E-6	*		
18 $T_3AY_fOL_r$	3.7E-7	*		
19 $T_3AB_oL_r$	7.8E-7	*		
20 $T_4AB_oL_r$	2.9E-7	*		
21 $T_5AY_fL_r$	4.1E-6	*		
22 $T_5AB_oL_r$	2.9E-6	*		
23 $T_6AB_oL_r$	6.3E-6	*		
24 $T_7AB_oL_r$	4.6E-6	*		
25 T_8AL_r	1.7E-7	*		
26 RR_oL	1.2E-5	*		
27 RR_oC	4.8E-6	*		
28 H_1Z	1.1E-6	*		
29 WE_vKC	1.2E-5	3E-7	4E-9	3E-7
				2.3E-6

* DC failures contribute less than 1E-8/yr to this sequence

Table VIII-3.B-5 (continued)

B	- Spurious Opening of Turbine Bypass Valve	=	.1/yr
H_1	- High Energy Pipe Break in Steam Tunnel	=	3.8E-6/yr
P	- Loss of Offsite Power	=	.13/yr
R	- RDS Valve-Spurious Opening	=	1.2E-3/yr
S_2	- Medium LOCA	=	1E-4/yr
S_4	- Medium Steam Line Break Inside Containment	=	1E-4/yr
S_7	- Large LOCA	=	1E-5/yr
T_1	- IPR/PR Failure	=	.18/yr
T_2	- Spurious Opening of Turbine Bypass Valve	=	.1/yr
T_3	- Loss of Feedwater	=	.16/yr
T_4	- Loss of One Feed Pump	=	.14/yr
T_5	- Load Rejection	=	.59/yr
T_6	- Loss of Main Condenser	=	1.0/yr
T_7	- Loss of Offsite Power	=	.13/yr
T_8	- Miscellaneous Scrams	=	.56/yr
W	- Spurious Closure of an MSIV	=	.06/yr

A	- Failure of RPS
B_c	- Failure of Turbine Bypass Valve to Reclose
B_o	- Failure of Turbine Bypass Valve to Open
C	- Failure of RDS/CS
E_v	- Failure of Emergency Condenser Valves to Open
F_s	- Failure to Restore Power in the Short Term
I	- Primary System Isolation
K	- Safety Valves Reclose
L	- Failure of Long Term Cooling (PIS, SCS & EC)
L_r	- LPS Failure to Inject (to Prevent RDS)
O	- Recirculation Pump Trip
Q	- Failure of Emergency AC Power
R_o	- Failure of RDS Valve to Remain Closed
Y	- Failure of Inventory Makeup
Y_f	- Failure of Feedwater for Inventory Makeup
Z	- MSIV Closure
CS	- Core spray
EC	- Emergency condenser
LPS	- Liquid poison system

Table VIII-3.B-5 (continued)

PIS - Post incident system

RDS - Reactor depressurization system

SCS - Shutdown cooling system

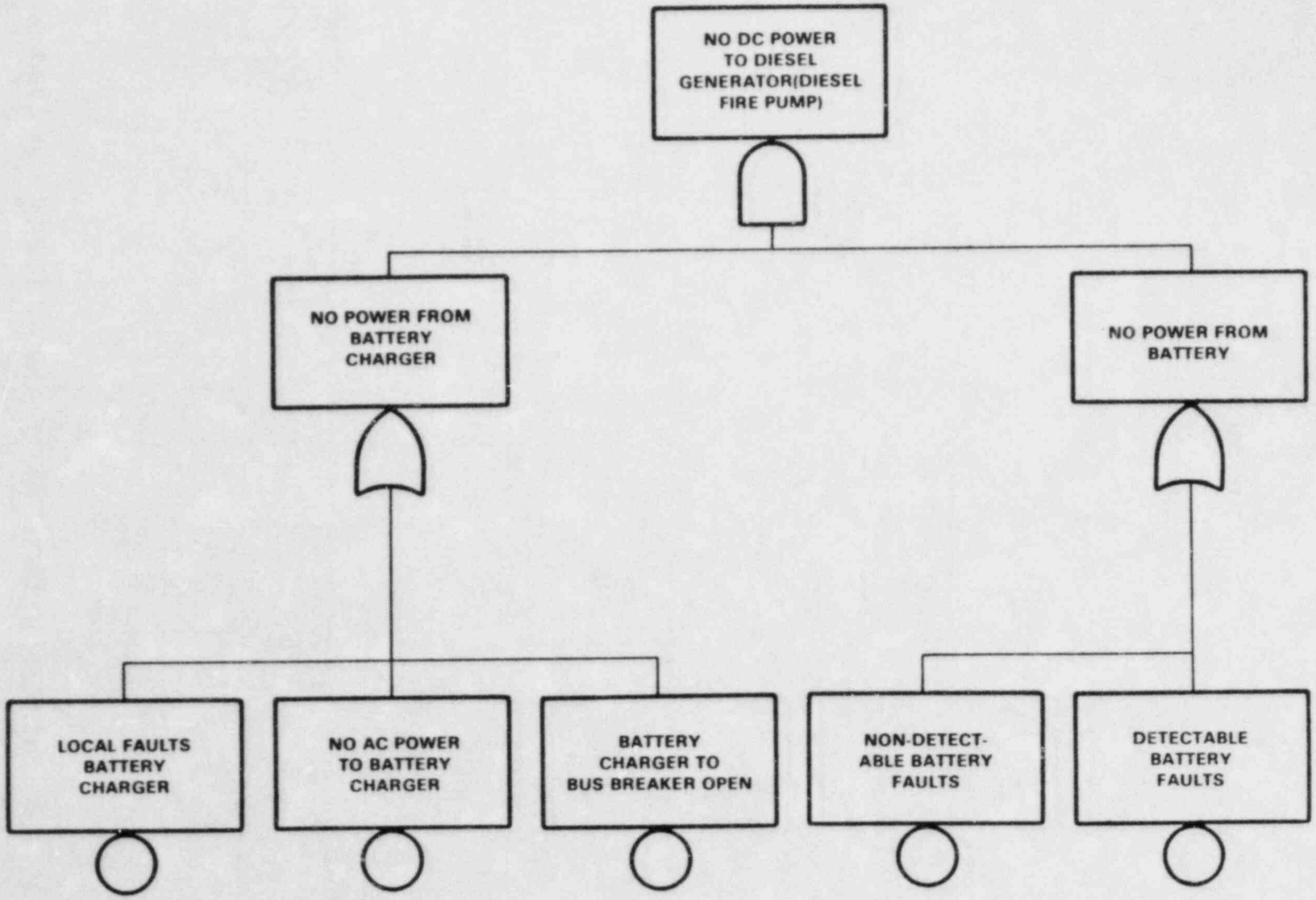

Figure VIII-3.B-1. FAULT TREE FOR LOSS OF DC POWER TO DIESEL GENERATOR (DIESEL FIRE PUMP)

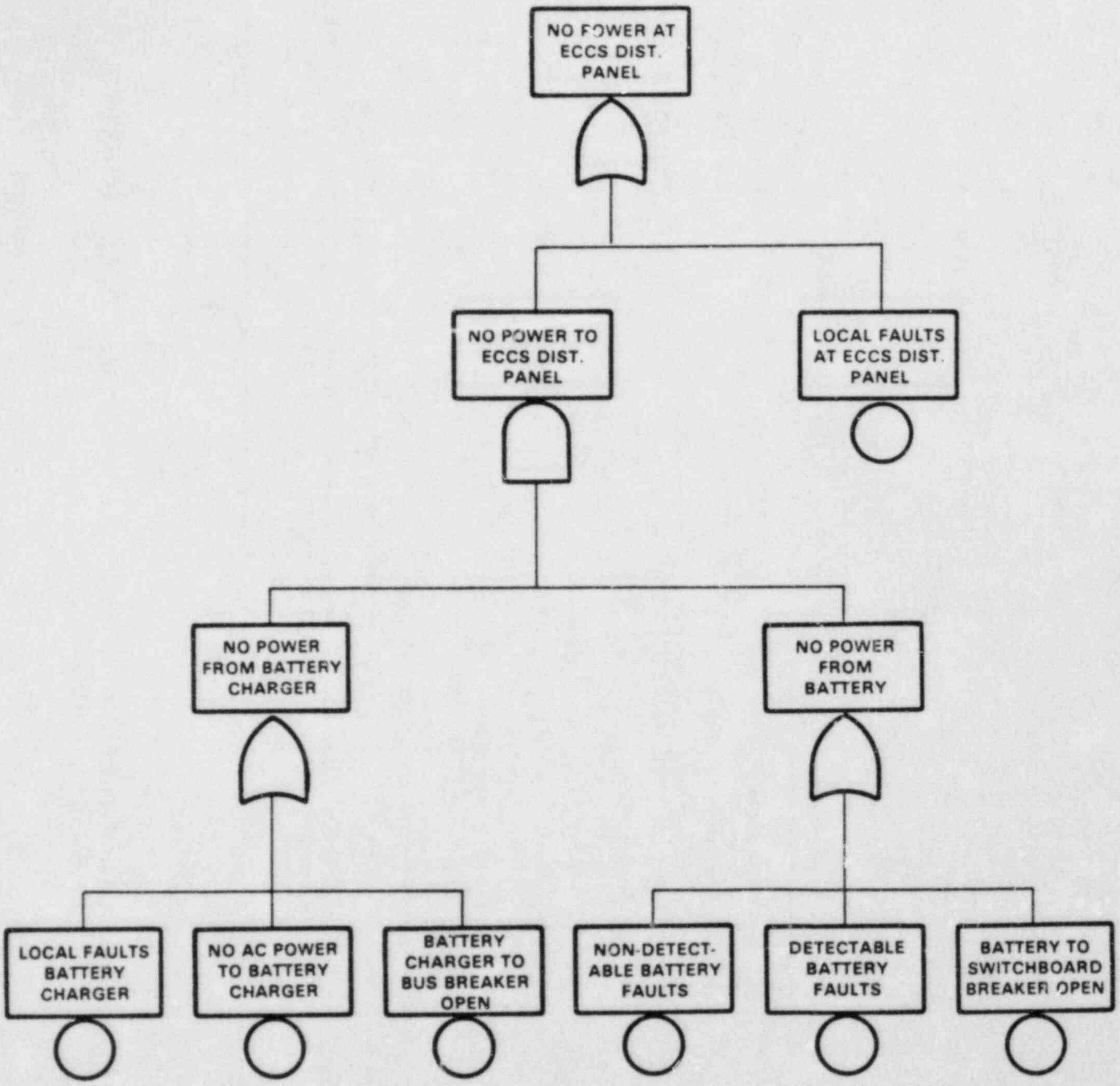

Figure VIII-3.B-2. SIMPLIFIED DC POWER FAULT TREE FOR UPS TRAINS

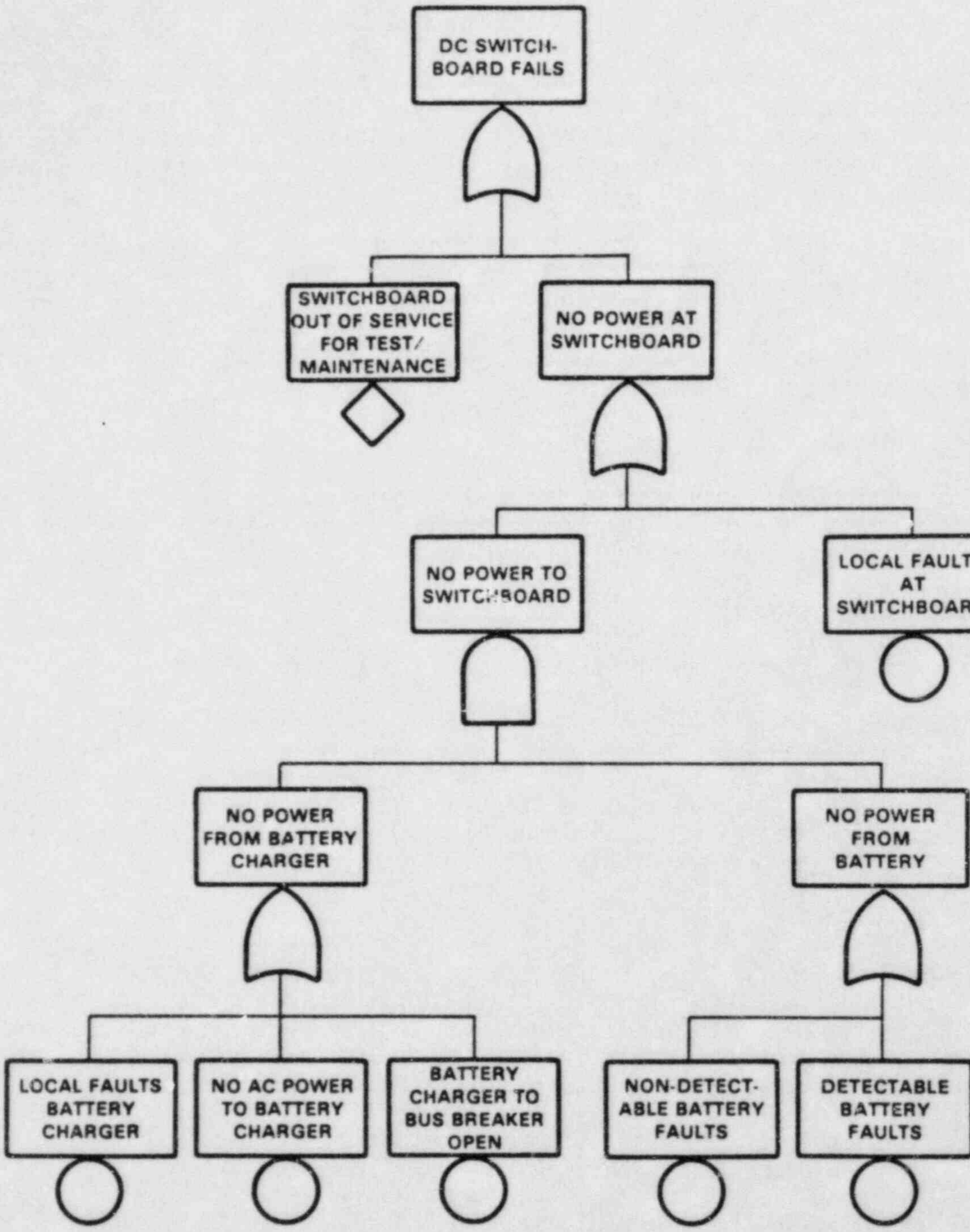

Figure VIII-3.B-3. SIMPLIFLIED 125V DC POWER FAULT TREE

VIII-4 Electrical Penetrations of Reactor Containment

1. NRC Evaluation

Adequate protection for the low voltage AC and DC electrical penetrations does not exist at Big Rock Point. The operating time of the backup circuit breakers is excessive; given an overcurrent fault and failure of the primary circuit breakers the result will be the failure of the penetration seal.

Current criteria requires that for each penetration, protective systems should provide primary and scondary protection devices to prevent a single failure in conjunction with a circuit overload from impairing containment integrity. These requirements were developed to prevent a single failure from allowing excess current in the penetration conductors that could adversely affect penetration seals.

2. NRC Recommendations

The recommendation made for the low voltage penetrations at Big Rock Point is to provide adequate backup circuit breakers which would provide timely protection in the event of failure of the primary protective devices.

3. Systems Affected

The system affected is the containment isolation system.

4. Comments

In a LOCA environment, electrical penetrations may not be capable of maintaining their integrity given a failure of the primary circuit breakers and the existence of an electrical fault. Table VIII-4-1 lists the electrical penetrations present at Big Rock Point.

5. Analysis

A penetration fault in a LOCA environment requires that two events occur. First an electrical fault (circuit overload) must exist and the breaker (protection device) on that circuit must fail to isolate the circuit. The data used in this analysis is shown in Table VIII-4-2. The failure of an electrical penetration due to a fault would be:

= (number of containment cable penetrations) x
P (electrical component failure) x P (breaker failure).

For the DC circuits this would be:

= (2070) (3.6E-5) (1E-3) = 7.4E-5

For the low voltage AC circuits:

= (291) (3.6E-5) (1E-3) = 1.1E-5

The combined failure probability for these electrical penetrations is:

8.5E-5

The Type 7 penetrations were not included on the failure analysis due to the small penetration size (1 1/2 inches diameter) and the rationale that only those penetrations four inches or larger in diameter are considered significant in terms of possible containment leakage (WASH-1400, Appendix II, Section 5.12.).

It has been conservatively assumed that all shorted faults are failures that will result in a circuit overload.

6. Conclusion

The failure probability of containment integrity due to the failure of an electrical penetration not currently meeting the GDC, caused by an overloaded circuit is calculated to be 8.5E-5. The containment leakage probability calculated for the Big Rock Point PRA was on the order of magnitude of 1E-1.

Due to the relative size of the containment isolation failure probabilities in this topic and the Big Rock Point PRA we rate the risk significance of this issue as low.

Table VIII-4-1

ELECTRICAL PENETRATION OF PRIMARY
CONTAINMENT AT BIG ROCK POINT

TYPE	NUMBER OF PENETRATIONS	SIZE OF PENETRATION (diameter)	NUMBER OF CABLES IN EACH PENETRATION	FUNCTION OF PENETRATION	ELECTRICAL CATEGORY
1	20	6"	92	General purpose power and instrumentation	DC
2	1	6"	52	Telephone and PA lines	low volt AC
3	2	6"	52	Thermocouple cables	low volt AC
4	3	6"	20	General purpose power	low volt AC
5	6	6"	6	Large power feeders	high volt AC
6	1	6"	4	Equipment grounds	
7	5	1 1/2"	8	Personnel hatch locks, etc.	low volt AC
8	6	8"	12	Instrument cables co-axial	low volt AC
9	1	8"	3	Computer cables and instrumentation	low volt AC
10	2	8"	39	RDS instrumentation and control	DC
11	1	8"	58	RDS instrumentation and control	DC
12	1	8"	91	RDS instrumentation and control	DC

Table VIII-4-2
FAILURE DATA SUMMARY

FAILURE	FAILURE RATE*	FAULT EXPOSURE TIME	UNAVAILABILITY
Solid State device fails shorted	1E-7/hour	360 hours	3.6E-5
Circuit Breaker fails to transfer	1E-3/demand		1E-3

*Data taken from WASH-1400

IX-5 Ventilation Systems

1. NRC Evaluation

The ventilation systems at the Big Rock Point Plant were found to be in accordance with current criteria with three possible exceptions. The ventilation system for the electrical equipment room consists of a service water cooler, recirculating room cooler which is not redundant, nor powered by the emergency diesel. The equipment serviced by this system in the electrical equipment room includes; the main station battery, two motor generator sets, instrument air compressors, 480V switch gear and cable spreading. The shop area ventilation system provides ventilation for the reactor depressurization system (RDS) batteries. The shop area ventilation system is not powered by an emergency bus and therefore following a loss of offsite power event ventilation to the RDS batteries will be lost. Finally, the diesel generator room has a passive ventilation system. The effects of a nonactive ventilation system on the electrical panel in this area have not been fully evaluated.

2. NRC Recommendation

For each of the three areas that are described above the SEP branch of the NRC made the following recommendations. The licensee should evaluate the consequences of losing the ventilation system in the electrical equipment room. Further information should be provided by the licensee regarding hydrogen buildup around the RDS batteries during periods following a loss of power event. The amount of hydrogen generated during the length of time the batteries are discharging with no ventilation should not exceed the minimum combustion limits. The effects of a nonactive ventilation system on vapor dispersion and service conditions for the electrical panel in the diesel generator area should be analyzed by the licensee.

3. Systems Affected

The systems affected by this issue are the AC power system and the RDS.

4. Comments

The intent of this issue analysis is to determine if further effort to evaluate the need for ventilation in these three areas is warranted. At this time much of the information required for a quantitative analysis to be performed is not available. Such an analysis would require information on the heat generated in the various areas under several plant operating conditions and the effects of increased temperatures in the three areas on the failure probabilities of the equipment in the areas. Without this information extremely conservative assumptions would have to be made to perform a quantitative analysis. Since this information is not available no quantitative analysis will be performed, but rather a qualitative assessment will be made.

5. Analysis

The equipment contained in the electrical equipment room provides power to many of the essential systems required to bring the Big Rock Point Plant to a safe condition following an accident initiator. (This can be verified by examining the Big Rock Point PRA fire analysis. An unsuppressed fire in this area is assumed to result in a core melt accident.) The ventilation system for the electrical equipment room is a nonredundant system that is not powered during an LOSP condition. If this ventilation system should fail, the heat generated by the equipment in the room could eventually result in equipment failures. (The failure rates of the equipment would increase as the temperature increases.) However, without more detailed information it is not possible to determine which equipment would fail or in what order the equipment would fail.

If it is assumed that all the equipment would eventually be affected by the increased temperature the consequences would be significant due to the importance of the equipment in the electrical equipment room. For these reasons the ventilation requirements for the equipment in this area should be more fully analyzed.

The ventilation system for the RDS batteries is a nonredundant system that is not powered during an LOSP condition. If the assumption is made that ventilation is required for the continued operation of the RDS batteries the probability of a loss of ventilation in this area could be a significant contributor to the system failure probability. The RDS is an important safety system that appears in many of the dominant accident sequences in the Big Rock Point PRA. It is to be expected that any failure that would adversely affect the system failure probability would be a contributor to the risk due to core melt.

The equipment in the diesel generator room may or may not require an active ventilation system in order to function. If one is required then when the diesel generator is needed the electrical panel in the diesel generator room could be failed due to the lack of ventilation. This would eventually result in a loss of power from the emergency generator. Lack of an active ventilation system should not prevent the diesel generator from starting. The lack of ventilation would be expected to require some time to take effect and, assuming it is required, would have the same effect on the emergency AC power system as a failure of the emergency diesel generator to continue to run. Thus during a loss of offsite power no additional failures would be required to fail the emergency source of AC power after it has started.

In the Big Rock Point PRA there is one dominant accident sequence that involves a loss of offsite power and a failure of the emergency AC power supply after the diesel generator had successfully started. This sequence contributes less than .1% to the core melt frequency of the Big Rock Point Plant. Ventilation failures would not be expected to make this a significant dominant accident sequence.

6. Conclusion

It was assumed that ventilation is required for each area analyzed and that a loss of ventilation could affect all equipment in the area. This effort should be used only to determine whether or not further analysis should be performed to determine if ventilation is indeed required for the three areas considered. The lack of an active ventilation system in the emergency diesel generator room does not appear to be a significant contributor to the core melt frequency at the Big Rock Point plant. We rank this ventilation topic of low risk significance.

If ventilation is required in the electrical equipment room and in the RDS battery area the loss of ventilation in these two areas could have a significant effect on the core melt frequency at Big Rock Point. We rank the loss of ventilation in these two areas to be of high risk significance.

XV-8 Control Rod Misoperation

1. NRC Evaluation

The Big Rock Point Nuclear Power Plant does not satisfy General Design Criteria 25.

2. NRC Recommendation

No specific recommendations have been made at this time.

3. Systems Affected

The issue affected is the reactivity control system.

4. Comments

The NRC analyzed this event at both startup and at operating power levels. At startup conditions the reactivity control system meets GDC 25. In the NRC analysis at operating power conditions conservative assumptions were used and it was found that for two assemblies specified acceptable fuel design limits might be exceeded with a single malfunction of the reactivity control system. The assumed power distribution was a chopped cosine. The actual power distribution in the reactor will be relatively flat over a large portion of the elevation, and the thermal conditions would be improved over those for a chopped cosine distribution. Assuming a flat power distribution, the NRC analysis shows no rods exceed the fuel design limits.

5. Analysis

In order to attain the conditions where, according to NRC calculations, 2 assemblies exceed fuel design limits, these failures to scram the reactor must occur (fails to scram on high flux trip, loss of feedwater suction, or loss of condenser vacuum). According to NRC "such an event has a very low probability of occurrence." This is supported by the Consumer Power Company's PRA (the Big Rock Point PRA) where on page VIII-40 the failure to scram rate is estimated as 3.5E-5 per demand. Thus the overall probability of the control configuration being placed in a situation where the fuel design limits could be exceeded is the probability of over withdrawing a control rod times the probability of failing to scram. The probability of over withdrawing a control rod is an error of commission whose rate is on the order of 10^{-3}. Thus the overall probability is on the order of 10^{-7} - 10^{-8} per control rod adjustment, given a single opportunity for scram. With multiple opportunities for scram the probability would be much less.

6. Conclusions

This issue has little effect on risk and has little potential for significantly reducing risk. It is rated as having low risk significance.

XV-18 Radiological Consequences of Failure of Main Steam Line Break Outside Containment

1. NRC Evaluation

NRC's evaluation of the radiological consequences of the failure of main steam line break (MSLB) shows that they exceed the acceptance criteria for the equilibrium coolant limit but they do not exceed the values of 10 CFR Part 100.

2. NRC Recommendation

It is recommended that Big Rock Point adopt the GE Standard Technical Specifications for BWRs concerning iodine activity and control in the reactor coolant.

3. Systems Affected

This issue affects probable offsite consequences.

4. Comments

NRC evaluation of the radiological consequence of MSLB is based upon very conservative assumptions. The licensee's assessment calculated the radiological consequences using current technical specification limits to be 92 Rem. This value exceeds the NRC's acceptance criteria. It should be noted that the plant has operated for several years and if the licensee's records are complete (for coolant activity and meteorological data), an assessment could be made using an historical equilibrium coolant activity and average meteorology as well as the shutdown limits. Such an assessment would show how the plant has actually performed regarding the requirements of 10 CFR 100.

5. Analysis

PRAs have shown that the dominant contributor to risk from a nuclear power plant is a core melt accident. Although a significant dose rate from a MSLB outside containment is credible under very conservative scenario, it does not offer an opportunity to significantly reduce the risk from the operation of a nuclear power plant. This follows from an examination of the probability of a MSLB. In Appendix I of Consumers Power Company's PRA analysis (the Big Rock Point PRA) the sequences leading to MSLB are analyzed. The overall probability of MSLB is on the order of 1×10^{-8} per year.

6. Conclusion

This issue has little effect on risk and is rated as having low risk significance.

References

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3. "Probabilistic Risk Assessment, Big Rock Point Plant," Consumers Power Company, Docket 50-155.

4. Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants, WASH-1400 (NUREG-75/014), U.S. Nuclear Regulatory Commission, October 1975.

5. "Risk Based Categorization of Haddam Neck SEP Issues," SAI-83-128-WA, Science Applications, Inc., February 15, 1983.

6. Swain, A.D., and H.E. Guttmann, "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, October 1980.

ADDENDUM TO SAI-83-130-WA Revision 1

CONVERSION OF RESULTS OF

SAI BRP SEP ISSUES

ANALYSES TO POPULATIONAL EXPOSURE REDUCTION

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In response to an NRC request, SAI has prepared this short summary to provide additional information on the evaluation of Big Rock Point SEP Issues Specifically this summary contains information on the consequen. ⁻⁻duction analysis, which was based on information provided by the NRC and results obtained from a previous SAI report entitled "Risk Based Categorization of Big Rock Point SEP Issues", Revision 1 (SAI-83-130-WA). The objective of this effort is to present the results documented in the cited report in a format such that they can be readily compared to the results obtained from different efforts. The issues that these results are to be compared with are those presented in the SAI report "Risk Based Analysis of Open Issue for the Big Rock Point Nuclear Power Plant", draft report dated June 27, 1983, and those analyzed as part of the NRC risk-based analysis of SEP issues.

The method for evaluating the consequence reduction for a particular SEP issue was developed by the NRC and is presented in the following expression:

$$\begin{matrix}\text{reduction in}\\ \text{consequences}\end{matrix} = \begin{pmatrix}\text{reduction in}\\ \text{core melt}\\ \text{frequency}\end{pmatrix} \times \begin{pmatrix}\text{containment}\\ \text{failure}\\ \text{probability}\end{pmatrix} \times \begin{pmatrix}\text{consequence}\\ \text{conversion}\\ \text{factor}\end{pmatrix}$$

The core melt frequency for each issue was calculated and is presented in the SAI report SAI-83-130-WA, Revision 1. The containment failure probability for each dominant accident sequence is taken from the Big Rock Point Probablistic Risk Assessment and the consequence conversion factor (1.2 E+6 man-rem/event) was provided by the NRC. Of the issues analyzed in the SAI Big Rock Point SEP report, issue IX-5 was ranked as a high risk issue, III-10.A and VII-1.A as medium risk issues, and all others as low risk issues. The ranking method used was based on the changes in core melt frequency without considering the consequences resulting from such changes. At this time, it is preferred to present the consequences associated with the core melt frequency changes to ascertain the populational risk for the above issues, and to provide a basis for comparison to other BRP issue analyses.

A qualitative analyses was performed for issue IX-5 since much of the information required to do a realistic quantitative analysis was not available. The qualitative assessment was performed to indicate whether or not further analysis of the need for ventilation systems in certain plant areas was justified. Therefore, there is no core melt frequency reduction calculated for this issue. The equipment that could be affected by this issue represents a significant portion of the important safety-related equipment available at the Big Rock Point plant. Potentially, failure of the ventilation systems could result in a large change in the core melt frequency and the associated popoulational exposure. For this reason this issue was ranked high in risk significance.

The results of the analysis to determine populational exposures are presented in Tables 1 and 2, and the following paragraphs. For issue VII-1.A, the only affected system is the RPS. With a core melt frequency reduction of 1.7E-4/yr, a containment failure probability of 0.99, and a consequence conversion of 1.2 E+6 man-rem/event, the analysis shows that a total reduction of 202 man-rem/yr in the populational exposure. Table 1 shows the dominant sequences affected by issue III-10.A. The combined consequence reduction calculated for this issue is 28 man-rem/yr. As presented in the SAI Big Rock Point SEP report, both of these issues were ranked as medium risk issues, with issue III-10.A being ranked slightly above issue VII-1.A. If the consequence reduction results were used as the ranking criterion instead of the reduction in core melt frequency, it is expected that issue VII-1.A will be ranked higher than issue III-10.A.

The remaining issues, identified as low-risk issues in SAI-83-130-WA, either do not significatnly contribute to the core melt frequency or do not significantly affect the performance of their respective systems. For these reasons, it is expected that the consequence reductions associated with these issues are negligible. As an example, Table 2 shows the results of the consequence reduction analysis for issue VIII-3.B (which was ranked as a low-risk issue in the SAI Big Rock Point SEP report. A value of approximately 2 man-rem/yr is calculated as the total reduction in the populational exposure for this issue. This reduction, in comparison to those calculated for other issues, such as VII-1.A, is considered to be negligible. Thus, it is concluded that the low risk issues identified in the SAI Big Rock Point SEP report are indeed low-risk, even when consequence reduction results are being considered.

The results of the calculations of populational exposure reductions for the original Big Rock Point SEP issues are presented in Table 3.

Table 1. Consequence Reduction Analysis for Issue III-10.A

System/Dominant Sequences	Core Melt Frequency Reduction(yr^{-1})	Containment Failure Probability	Consequence Conversion Factor (man-rem/event)	Consequence Reduction (man-rem/yr)
TENC	2.1 E-7	.2	1.2 E+6	0.05
TZL	7.8 E-6	.23	1.2 E+6	2.1
Y_fL	8.9 E-6	.2	1.2 E+6	2.1
MNL	3.3 E-6	.2	1.2 E+6	0.8
ME_vNC	1 E-6	.2	1.2 E+6	0.2
ME_mNC	3.4 E-7	.2	1.2 E+6	0.08
PE_vF_sC	2.0 E-6	.2	1.2 E+6	0.5
PE_mF_sC	8.8 E-6	.2	1.2 E+6	2.1
PIF_sYC	5.6 E-7	1.0	1.2 E+6	0.7
$PQIF_sC$	1 E-7	1.0	1.2 E+6	0.1
S_1E_mC	5.6 E-6	.2	1.2 E+6	1.3
S_2C	5.6 E-7	.23	1.2 E+6	0.1
S_3E_mC	5.6 E-6	.2	1.2 E+6	1.3
UL	3 E-6	.23	1.2 E+6	0.8
UE_vUC	1 E-6	.23	1.2 E+6	0.3
UE_mUC	1.1 E-5	.23	1.2 E+6	3.0
WE_vC	1 E-6	.2	1.2 E+6	0.2
WE_mC	3.5 E-7	.2	1.2 E+6	0.1
BB_cE_vC	5.2 E-7	.2	1.2 E+6	0.1
BB_cZY_fC	2.8 E-5	.23	1.2 E+6	7.7
RR_oC	7 E-6	.23	1.2 E+6	1.9
I_1E_mC	1.1 E-5	.2	1.2 E+6	2.6
TOTAL				≅ 28.0

Table 2. Consequence Reduction Analysis for Issue VIII-3.B

System/Dominant Sequences	Core Melt Frequency Reduction(yr^{-1})	Containment Failure Probability	Consequence Conversion Factor (man-rem/event)	Consequence Reduction (man-rem/yr)
RDS/CS Batteries				
$PQIF_sC$	5 E-9	1.0	1.2 E+6	0.006
All other LOSP sequences	6.7 E-7	0.2	1.2 E+6	0.16
125V DC				
PIF_sYL	2.3 E-7	1.0	1.2 E+6	0.27
PIF_sYC	2 E-7	1.0	1.2 E+6	0.24
$PQIF_sC$	1 E-6	1.0	1.2 E+6	1.20
WE_vL	1.8 E-7	0.2	1.2 E+6	0.04
WE_vC	1.4 E-7	0.2	1.2 E+6	0.03
BB_cZY_fL	1.2 E-7	0.23	1.2 E+6	0.03
BB_cZY_fC	9 E-8	0.23	1.2 E+6	0.02
WE_vKC	3 E-7	0.2	1.2 E+6	0.08
Subtotal				≅ 1.9

Table 3. Summary of Results:

Populational Exposure Reduction for Big Rock Point SEP Issues

Issue No.	Issue	Populational Exposure Reduction (man-rem/yr)
IX-5	Ventilation Systems	+++
VII-1.A	RSP Isolation	202
III-10.A	Thermal Overload Protection	28
VIII-3.B	DC Bus Voltage Monitoring	2
III-5.B	Pipe Break Outside Containment	*
III-8.A	Loose Parts Monitoring	*
V-5	RCPB Leak Detection	
V-10.A	Residual Heat Removal System Heat Exchanger Tube Failure	*
V-11.A	Isolation of High and Low Pressure Systems	*
V-11.B	RHR Interlock Requirements (Systems and Electrical)	*
VI-4	Containment Isolation System	*
VI-10.A	Response Time Testing	*
VII-3	Safe Shutdown Systems	*
VIII-4	Electrical Penetrations of Reactor Containment	*
IX-3	Service and Cooling Water Systems	*
XV-8	Control Rod Misoperation	*
XV-18	Radiological Consequences of Main Stream Line Failure Outside Containment	*

+++ Qualitative analysis was performed; no populational exposure reduction is calculated. Issue is considered to be potentially high risk.

* Negligible

ATTACHMENT 2

SAI-84-241-WA

RISK-BASED ANALYSIS OF SELECTED OPEN ISSUES FOR THE BIG ROCK POINT NUCLEAR POWER PLANT

Final Report

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EXECUTIVE SUMMARY

This report addresses the risk based importance of open regulatory issues for the Big Rock Point Plant. The issues are among those submitted by the licensee, Consumers Power Company, for resolution as part of the integrated assessment being performed by the Systematic Evaluation Program (SEP) branch of the U. S. Nuclear Regulatory Commission. Only issues that can be readily addressed using probabilistic risk assessment (PRA) techniques, are analyzed in this report. A plant-specific PRA, performed by the utility and currently under NRC review was used in these analyses to represent the plant as it is, i.e., as a baseline model. The study assessed the importance of each issue through quantitative analysis of the changes in the Big Rock Point PRA fault trees and event trees. Changes in the frequency of dominant accident sequences and the associated changes in populational exposure represent the potential risk reduction due to resolution of each issue. The issues are ranked according to the magnitude of the reduction in the populational exposure.

Table Ex-1 summarizes the results of this report. Issues are listed in descending order of reduction in populational exposure. The remainder of the executive summary summarizes each issue and the issue analyses.

Table Ex-1. Issues Ranked by Populational Exposure Reduction

Issue Number	Issue Title	Man-Rem/yr Reduction
63	Containment Purging	210
75C	Fire Protection - Emergency Condenser Valve Circuits	204
44	BS&B Valve Data	85+
11	Turbine Bypass Valve EHC System	26+
17	PCS Isolation	21
75B	Fire Protection - RDS Radiant Energy Shield	7
8	Single Channel Reset	6
74	Reactor Coolant System Vents	5+
7	Scram Dump Tank Level Instrumentation	4
73	Control of Heavy Loads	*
50E	Containment Airlock	*
81	PORV Position Indication	*

*Negligible

+Represents a potential or upper bound reduction. Achievable reduction may be significantly less.

Issue 7: Scram Dump Level Instrumentation

In its generic letter 81-18, dated March 30, 1981, the NRC indicated that common-cause failures may be the most significant contributor to the unreliability of the scram systems of BWRs. As a result of this position diverse scram dump tank (SDT) level instrumentation is required for BWR plants. Big Rock Point has a single SDT and a single set of level instrumentation. If there is a common-cause failure of the level instrumentation at the SDT, back pressure in the tank could prevent complete insertion of the control rods during a scram. The analysis evaluated the contribution to the reactor protection system (RPS) failure probability due to common-cause SDT level instrumentation failures. A simplified system fault tree was constructed and quantified twice, once with common-cause SDT level instrumentation failures and once with no common-cause failures. The second quantification represents the RPS with an effective alternative to the non-redundant SDT level instrumentation. The reduction in the RPS failure probability, from 2.3E-6 to 6E-7, corresponds to a reduction in the expected core melt frequency that results in a reduction of approximately 4 man-rem/yr in the populational exposure.

Issue 8: Single Channel Reset

On three occasions during the past five years at the Big Rock Point Plant the scram valves and the scram dump tank (SDT) vent and drain valves have failed to open and close in the proper sequence when the reactor protection system has been reset. A primary coolant to containment leakage path results when the drain or vent valve fails to close prior to the scram valves opening. These events did not occur at reactor operating pressure but a licensee analysis has shown that if a similar event does occur at operating pressure a small LOCA would result. Therefore this plant data was used to develop a small LOCA initiating frequency for this type of LOCA. This frequency was then used in the dominant small LOCA accident sequences from the Big Rock Point PRA. After the core melt frequency due to this small LOCA was calculated a reduced small LOCA frequency was calculated based on the proposed modification, installation of redundant MOVs on the SDT vent and drain lines. The reduction in the core melt frequency from this reduced LOCA initiator corresponds to a 6 man-rem/yr reduction in the populational exposure.

Issue 11: Turbine Bypass Valve EHC System

The turbine bypass valve Electro-Hydraulic Control (EHC) system at Big Rock Point has shown a tendency to spuriously open or fail to open the turbine bypass valve. A spurious opening can initiate a transient and can, in conjunction with other failures, result in a failure to isolate the primary system. A failure to open can cause a loss of the full power main heat sink for the primary coolant system during a transient. These control system-induced instabilities have convinced plant staff to reevaluate the relative effectiveness of the EHC system and to consider possible corrective actions. Since detailed EHC system design data were not available, it was not possible to pinpoint causes for the EHC failures. Instead, a sensitivity analysis was used to provide some insight into the potential risk reduction possible through improved reliability of the EHC system and therefore the turbine bypass valve. In the analysis, reduced turbine bypass valve failure probabilities and frequencies were used in the appropriate dominant accident sequences from the Big Rock Point PRA. The smaller failure probabilities and frequencies yielded a reduction by a factor of ten in the dominant accident sequence frequencies and a corresponding reduction in the populational exposure of 26 man-rem/yr.

Issue 17: PCS Isolation

Eight primary coolant system vent and drain lines at Big Rock Point have only a single manual valve for isolation of the primary coolant system from the containment atmosphere. Failure, a severe rupture, of any one of these valves would result in a small interfacing system LOCA. The valve failures are expected to occur with a frequency of 1.9E-3/yr, using data from the Big Rock Point PRA, with a resultant core melt frequency of 8.9E-5/yr. The proposed modification is to add a second manual valve or a pipe cap so that two failures would be required to create a LOCA. These modifications would effectively eliminate the contribution to the interfacing system LOCA frequency due to leakage through these vent and drain lines. This results in a reduction in the populational exposure of 21 man-rem/yr.

Issue 44: BS&B Valve Data

A number of control systems at Big Rock Point depend on air-operated valves. It is possible that normal air pressure to these air-operated valves may not be sufficient to stroke the valves. (It has not been fully established that there is a problem with the air system at Big Rock Point. This analysis is intended only to indicate the potential risk significance if a problem does exist. If there are no problems with the air systems this is a non-issue with no risk significance.) If this is the case, the valve would not change position upon demand. It is also possible that the valve would fail to remain in the proper position if air pressure is required to maintain the valve position.

The following critical systems would be affected by air-operated valve failures: main condenser system, feedwater system, condensate system, control rod drive system, demineralized water system, liquid poison system, primary system isolation, vent valves (to relieve vacuum) and containment isolation. The analysis showed that the air-operated valve failures significantly affected the failure probability of two systems, the demineralized water system and the main condenser. (Data for valve failure due to air system inadequacies was developed from information for Issue 8.) All other systems were not significantly affected because (1) the valves failed in the proper safety position, (2) valve failures did not significantly affect system failure probabilities, or (3) the change in the system failure probability did not significantly affect the dominant accident sequences.

The air operated valve failures contributed 77 man-rem/yr and 8 man-rem/yr to the populational exposure due to induced failures of the demineralized water system and main condenser, respectively.

Issue 50E: Containment Airlock

Appendix J to 10 CFR 50 requires airlock door seal testing after every use (within 72 hours of use), or during periods of frequent use, every 72 hours. The containment airlock door seal testing program at the Big Rock Point Plant does not fulfill this criteria. Currently, the Big Rock Point airlock door seals are used frequently but are only tested every 6 months.

The analysis evaluated the failure probability of the containment airlock door seals, assuming testing every 3 days and 6 months. The test history of the door seals at Big Rock Point was used to develop a failure rate for the airlock door seals. The results of the analysis showed a reduction of almost 8E-3 in the airlock door seal leakage probability, a factor of 10 reduction. However, this results in a negligible reduction in the populational exposure, due to the small absolute magnitude of the door seal leakage probability and the small relative magnitude compared to the expected containment leakage probability, which is on the order of 0.2.

Issue 63: Containment Purging

The containment vents at the Big Rock Point Plant are normally open. In the event of an accident, the vent valves are supposed to close. Failure of these valves to close was one of the dominant contributors to the containment leakage probability in the Big Rock Point PRA. In the event of a LOCA or transient that results in containment pressurization, debris inside the containment could be transmitted to the vent system ductwork and prevent vent valve closure. The proposed resolution is to install debris screens over the vent ducts to prevent debris accumulation around the valves. Also evaluated as part of this issue was the benefit that could be gained through limited purging of the containment (currently the Big Rock Point containment is continuously purged) and increased testing of the vent valves.

Since the exact relationship between debris accumulation and vent valve failure is not known the analysis performed was a sensitivity analysis. The failure probability used in the Big Rock Point PRA for vent valve failures was increased by 1, 50, and 100% to determine some potential consequences due to debris-induced vent valve failures. For the 100% increase in the vent valve failure probability, the populational exposure changed by approximately 111 man-rem/yr.

Decreasing the test interval for the vent valves from 18 months to 6 months will yield a populational exposure reduction of 75 man-rem/yr. Limited purging, if possible, will result in an 81 man-rem/yr reduction in the populational exposure if purging is limited to 90 hours per year. The use of increased testing and limited purging results in a 99 man-rem/yr reduction in the populational exposure.

Issue 73: Control of Heavy Loads

Generic Technical Activity Task A-36 was established to systematically examine staff licensing criteria and the adequacy of measures to assure the safe handling of heavy loads. One of the resulting recommendations called for the installation of mechanical stops or electrical interlocks to prevent crane travel over fuel elements or shutdown-related systems. The issue is whether installation of such equipment would lead to a significant reduction in public risk.

The risk due to movement of heavy loads depends on several factors: (1) the amount of time cranes are in operation; (2) the fraction of operation time spent over particular systems; (3) the likelihood per hour of operation of a load drop; and (4) the expected consequences of a load drop in terms of core melt and population exposure.

The product of the first two factors may be thought of as an "at risk" time for any given system. For Big Rock Point, if operators make no effort to avoid operation over sensitive areas, these times are estimated to range as high as 48 hours per year but are much more likely to be a few hours per year or less for any given system. The third factor, the failure rate, is estimated to be about 3E-6/hour. The frequency of load drops on a single system, again with no evasive action by the operators, might therefore be expected to be on the order of 6E-6/yr with an upper bound of about 1E-4/yr. To be conservative, we assume that, given a load drop on any system in a sensitive area, core melt is certain. We thus take the frequency of load drops in sensitive areas as a very conservative measure of risk in the present analysis.

If none of the operations over sensitive areas are avoidable, the addition of stops and interlocks would be meaningless. If some or all of such operations are avoided by means of procedures and administrative controls, the expected frequency would be reduced by the probability of operator failure to follow correct or adequate procedures. The latter probability is conservatively estimated to be about 0.01. Thus, even if all operations over sensitive areas were theoretically avoidable, the maximum potential reduction in load drop frequency on a single system would be about

6E-6 (0.01) = 6E-8/yr. As shown in the detailed analysis, the total potential reduction considering all systems is expected to fall within a range of about 3 to 6E-6/yr. This estimate accounts for a wide range of variation among individual systems. This range of core melt frequency is small compared to that from other causes. We therefore conclude that addition of stops and interlocks would have a minimal impact on risk and would result in a negligible reduction in populational exposure.

Issue 74: Reactor Coolant System Vents

This NRC-initiated issue, as part of NUREG-0737, deals with the ability to vent the primary coolant system of hydrogen that can accumulate during a core damage accident. Currently the Big Rock Point primary system vent is not seismically qualified, no procedures exist for its use and there are no provisions for test connections.

Upgrading the vent system to an operational condition could be of benefit in situations where high reactor pressure is maintained and the high pressure heat removal capabilities have been lost. The generation of hydrogen results from a core damage accident. The benefit to be derived from the vent is a possible recovery of a core damage accident prior to its evolving into a core melt. The analysis conservatively evaluated the combination of initiators, transients and LOCAs, and system failures necessary to produce the combination of conditions outlined above.

Two assumptions were made in order to calculate a potential reduction in the populational exposure due to the installation of an operable event. First, given the conditions outlined above it is still possible to recover from the core damage accident before it becomes a full core melt if the hydrogen is vented. The second assumption is that once the hydrogen is vented either the main condenser or the emergency condenser can be recovered and act as a heat sink. Using these assumptions a reduction of approximately 5 man-rem/yr in the populational exposure will result from the existence of an operable primary system vent at Big Rock Point.

Issue 75B: Fire Protection - RDS Radiant Energy Shield

This issue deals with the possibility of a fire disabling the RDS/core spray system, the emergency condenser and inducing a loss of offsite power. The three potential fire areas are: the core spray pump room, the south face of the steam drum wall and the area where the emergency condenser is located. A simplified model was constructed to represent the possibility of a fire in one of these three areas that would ultimately cause a loss of offsite power. (The licensee claims that it is not possible for a fire in these areas to result in a loss of offsite power.) Under the assumptions of the analysis the fires in these areas did contribute to the risk due to the operation of the plant. The proposed modifications, fire shields between the RDS/core spray system and the emergency condenser system, resulted in a 7 man-rem/yr reduction in the populational exposure.

Issue 75C: Fire Protection - Emergency Condenser Valve Circuits

This issue deals with the frequency and consequences of fires in three vital plant areas; the electrical equipment room, the penetration area outside containment, and the penetration area inside containment. An unsuppressed fire in any one of these areas could lead directly to a core melt, a result that is confirmed in the Big Rock Point PRA. Fires in these areas can disable the emergency condenser, RDS/core spray system and the power conversion system. The proposed modification is to reroute the emergency condenser cables in this area so that the fire could not disable all three systems The modification yielded a reduction in the core melt frequency that produced a reduction of 204 man-rem/yr in the populational exposure.

Issue 81: PORV Position Indication

In response to the Three Mile Island accident, the NRC is requiring that utilities be capable of monitoring Power Operated Relief Valve (PORV) position. This requirement has been extended to include safety-relief valves. There are no PORVs at the Big Rock Point Plant, but there are 6 relief valves that open or close at predetermined primary coolant pressure settings. These valves vent directly to the containment atmosphere.

If these valves should open, at least three monitoring systems in the containment will indicate a leak. The position indication on the relief valves will only indicate where the leak originates. Since the valves vent to the containment atmosphere, and they cannot be remotely operated, no recovery action is possible; the operator cannot reclose the valves. Thus the effect of installation of position indicators on the relief valves on the populational exposure is negligible.

I. INTRODUCTION

In its Systematic Evaluation Program the U. S. Nuclear Regulatory Commission is identifying deviations from current licensing criteria for older nuclear power plants. These deviations, i.e., issues, are to be resolved as part of integrated assessments of these older plants. In addition to the SEP issues for Big Rock Point the utility has requested that several other open issues, including generic issues, plant specific issues, and TMI action items be included as part of the SEP integrated assessment. This report presents the analysis and results of SAI's risk-based ranking of some of the open issues identified by Consumers Power Company for its Big Rock Point Plant. Only those open issues that can be readily addressed using PRA techniques, and which were not a part of the original set of SEP issues are analyzed.

Section II of this report discusses the methodology used to evaluate issues; which is similar to that used in the SAI report for the original set of SEP issues ("Risk Based Categorization of Big Rock Point SEP Issues" SAI-83-130-WA Rev. 1, June 30, 1983).

Section III contains the results of the analyses. The analysis for each issue is presented in Section IV.

II. Methodology for Risk-Based Ranking of Selected Big Rock Point Open Issues

The issues selected for evaluation in this report were those that could affect plant risk and whose resolution could have an impact on the results of the Big Rock Point PRA. Open issues that would not affect the risk (defined as populational exposures due to core melt accidents) were not included in this analysis.

Not all of the issues that could affect the risk due to a core melt were evaluated in this report. Many of the open issues are original SEP issues, and of these, the ones where PRA techniques are applicable were been analyzed previously (SAI report SAI-83-130-WA). A second set of open issues that are not amenable to current PRA techniques are beyond the scope of this report.

The overall study methodology is given in flow chart form in Figure 1. As can be seen in the flow chart, and in the discussion that follows, the Big Rock Point PRA was used to a considerable extent. As the baseline model for Big Rock Point, it provided information such as the expected core melt frequency, the dominant accident sequences, and the system fault trees. Modifications recently undertaken or contemplated by the licensee as a result of this PRA were not considered in this study. This baseline model was necessary to perform a quantitative analysis of the effects of the resolution of many of the open issues.

The methodology adopted in this study was to examine the impact of each issue on the systems it affects, and to assess the risk reduction potential of the issue by quantitative consideration of the fault trees and dominant accident sequences of the Big Rock Point PRA. The first step in each issue analysis was to determine what the resolution of the issue would affect; components, systems and initiating events. The effect of the issue resolution on each of these was then quantified. For initiating events a new initiating frequency was determined, new system failure probabilities were calculated for the systems. These new frequencies and probabilities were then used to recalculate the dominant accident sequence frequencies affected by the system or initiating event. (The dominant accident sequences were

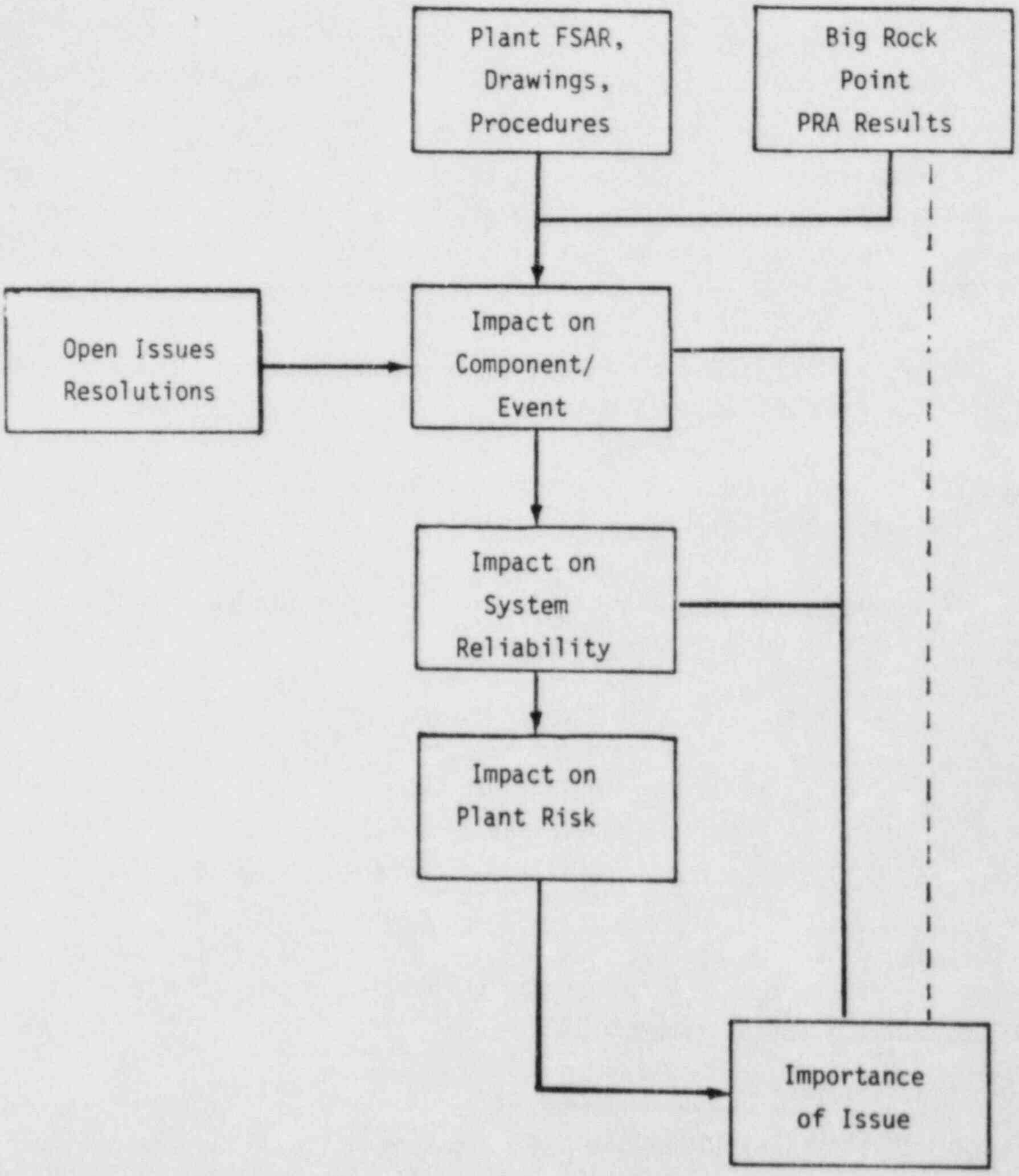

Figure 1. Study Methodology

taken from the Big Rock Point PRA.) The changes in the core melt frequency were used to calculate the changes in the populational exposure resulting from resolution of the issue. Populational exposure reductions were used to rank the issues. (Where possible, data from the Big Rock Point PRA were used. However, if the data appeared non-conservative, WASH-1400 data were used.)

The results of this analysis and the NRC analyses of open issues are to be combined and presented as part of the same appendix to the integrated assessment of Big Rock Point. Therefore the procedure used to calculate the populational exposure change resulting from the resolution of an open issue is the same as that used in the NRC evaluation of open issues.

Because of the Big Rock Point containment structure, the dominant containment failure mode is containment leakage. The consequences of a core melt accident with containment leakage dominate the risk due to plant operation. For this reason, no other containment failure mode is considered in calculating the populational exposure.

The populational exposure is calculated for the Big Rock Point using the following relationship:

$$E = F(CM)\ P(CL) 1.2E{+}6 \text{ man-rem/event},$$

where: E = populational exposure (man-rem/yr)
F(CM) = frequency of core melt
P(CL) = probability of containment leakage

Using data from the Big Rock Point PRA this relationship yields a total populational exposure for the Big Rock Point Plant of 440 man-rem/yr from all dominant accident sequences.

It should be noted that the licensee has made what appear to be significant changes in the area of containment isolation. Modifications include improvements in the containment vent valve control system and the addition of check valves in the feedwater lines. The vent valves and the feedwater line are two major leak paths through the Big Rock Point containment. These changes should greatly impact the containment leakage probability for most dominant accident sequences. At this time the NRC has not completed its review of the licensee's analysis of the effects of these changes and they have not been incorporated into this analysis. If the plant modifications do significantly reduce the containment leakage probability these modifications will greatly reduce the populational exposure reductions calculated in most of the issue analyses. Specifically, the results of the analyses for issues 8, 11, 17, 44, 63, 74, and 75B would be affected by these changes to the containment isolation systems at Big Rock Point. The only populational exposure reductions that will not be affected are those that result from most fire sequences (the fire fails the containment), the ATWS sequences (overpressure failure of the containment), and sequences where the MSIV fails to isolate.

A reduction in populational exposure is calculated using the change in the core melt frequency or in the containment failure probability obtained through the resolution of an issue. Some of the open issues do not affect a core melt sequence frequency, but rather affect the containment isolation probability; some issues affect both. The analysis of an issue that affects the containment isolation probability is performed in the same manner as for issues that affect systems that result in core melt frequency changes. The affected "system" is the containment isolation system, and changes in its failure probability can be used to calculate changes in the populational exposure.

III. Results

Twelve of the issues designated as open issues by Consumers Power Company were selected for analysis using the criteria outlined in Section II. These issues are listed in Table 1 in descending order of potential man-rem reduction in populational exposure. The man-rem reduction calculated for some issues does not necessarily indicate the actual man-rem reduction achievable; the reduction calculated may be larger than that achievable. Generally these issues are ones where important information regarding plant conditions was not available. Therefore some rather conservative assumptions were made. These assumptions were made so that a bounding analysis could be performed. The results for this type of open issue analysis indicate whether further examination of plant conditions is warranted. If the potential man-rem reduction is negligible, no further analysis to determine the plant conditions is warranted, while a relatively large reduction indicates further analysis may be prudent.

No attempt was made to determine what constitutes a significant reduction in populational exposure. The results are presented only to indicate what risk reduction is possible for each issue and to rank the issues relative to the other open issues analyzed in this report, in report SAI-83-130-WA, and to the open issues analyzed as a result of the NRC review of the Big Rock Point PRA.

Table 1. Issues Ranked by Populational Exposure Reduction

Issue Number	Issue Title	Man-Rem/yr Reduction
63	Containment Purging	210
75C	Fire Protection - Emergency Condenser Valve Circuits	204
44	BS&B Valve Data	85+
11	Turbine Bypass Valve EHC System	26+
17	PCS Isolation	21
75B	Fire Protection - RDS Radiant Energy Shield	7
8	Single Channel Reset	6
74	Reactor Coolant System Vents	5+
7	Scram Dump Tank Level Instrumentation	4
73	Control of Heavy Loads	*
50E	Containment Airlock	*
81	PORV Position Indication	*

*Negligible

+Represents a potential or upper bound on man-rem reduction. Achievable reduction may be significantly less.

IV. Analysis

The analysis of each issue is presented in this section.

Issue 7. Scram Dump Tank Level Instrumentation

1. Introduction

This issue is concerned with the possibility of a failure of the scram systems in Boiling Water Reactors (BWR's) as a result of high water level in the scram dump tank (SDT) and common-cause failure of the scram dump tank level instrumentation. (This issue is a result of NRC generic letter 81-18 which indicated common-cause failures may dominate scram system failures.) During BWR operation normal leakage of the water to the SDT is drained away and does not accumulate. If the drainage path is blocked, however, water accumulates in the SDT. Normally the SDT level instrumentation signals SDT accumulation of water in the SDT before the water level becomes unsafe. If a common-cause failure of the level instrumentation occurs, the water could reach a level where the back pressure in the SDT could prevent complete insertion of the control rods into the reactor during a scram.

2. Comments

The scram discharge system at Big Rock Point employs a single scram discharge (or dump) tank. The water discharged from the control rods as a result of leakage during normal operation and during a scram flows through 4" scram discharge headers. This water then flows to a 6" header and finally to the SDT. Figure 7.1 shows a simplified schematic of the SDT and associated level instrumentation.

Under normal operating conditions the water in the SDT and the headers drains through a 2" drain pipe to the containment sump. A one-inch vent line is also provided for venting the SDT. The 2" drain pipe and the 1" vent pipe each have an air-operated control valve (CVNC12, CVNC11), which is controlled by a solenoid-operated valve. During normal operation, the drain and vent valves are open to drain the leakage from the control rods. During a scram these valves are closed automatically to protect the integrity of the primary system. The water level in the scram dump tank is monitored by five level switches. These level switches are connected to the top and bottom of the tank through two 2" pipes with a manual valve on each line. These valves are always open during reactor operation. The manual valves,

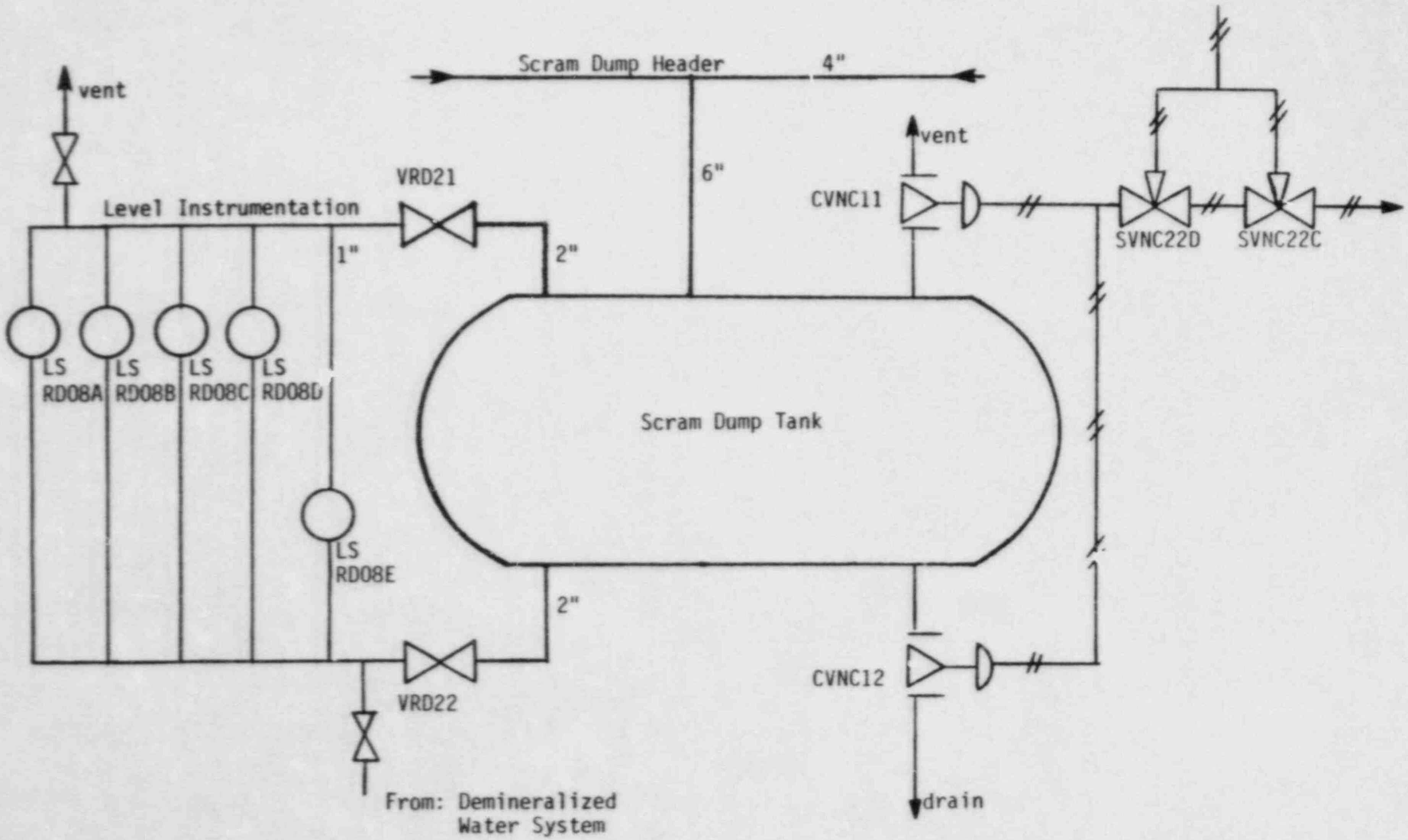

Figure 7.1 Simplified Schematic Of The Scram Dump Tank And Water Level Instrumentation

instrumentation piping and the level instruments are tested once every refueling by filling the scram discharge tank and observing the level switches' response to the rise in the water level.

3. Analysis

To assess the impact of the common-cause failure of the SDT level instruments, a fault tree for the failure of the SDT due to high water level was developed (Figure 7.2).

The fault tree is quantified using the data shown in Table 7.1. The common-cause failure probability of the SDT level instrumentation is calculated using a β factor of 0.1, i.e., the random unavailability of the level instruments is multiplied by 0.1 to get the unavailability of level instruments due to common-cause failure. The use of a β-factor is based on work performed by K. N. Fleming and P. H. Raabe, General Atomic report GA-14568. Their work has shown that the probability of multiple instrument failures, for instruments of the same design, given the failure of any one of the instruments can be calculated using a β-factor. The common cause failure probability is β x (probability of instrument failure). Comments on two operator error probabilities shown in Table 7.1 are necessary. The operator error O_2 is the human error probability in recognizing the incorrect position of the SDT drain valve if this valve was inadvertently left closed after the previous test or scram. The position of this valve is checked during a monthly walk-around.

The unavailability due to this human error can be expressed by the following relationship (NUREG/CR-1278, Chapter 6)

$$U = \frac{P\,\bar{d}}{\bar{T}}$$

where

- U is the average unavailability due to human error
- P is the probability of a human error that is not recovered
- $\bar{d}$ is the average downtime, i.e., the time that it takes before the error is recognized (essentially time between checks)
- $\bar{T}$ is the total time between tests.

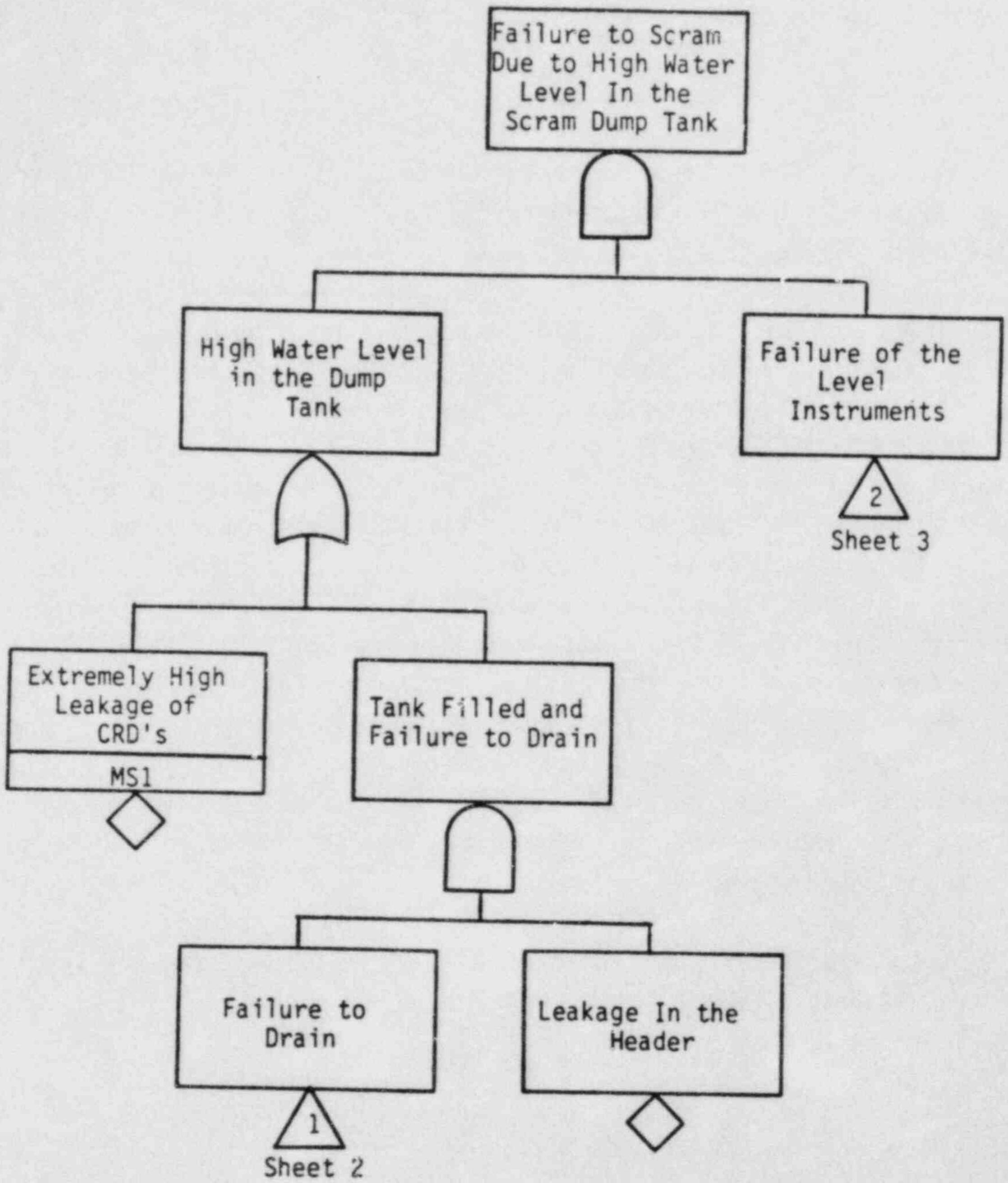

Figure 7.2 Fault Tree for the Event "Failure to Scram Due to High Water Level In the Scram Dump Tank"

Sheet 1

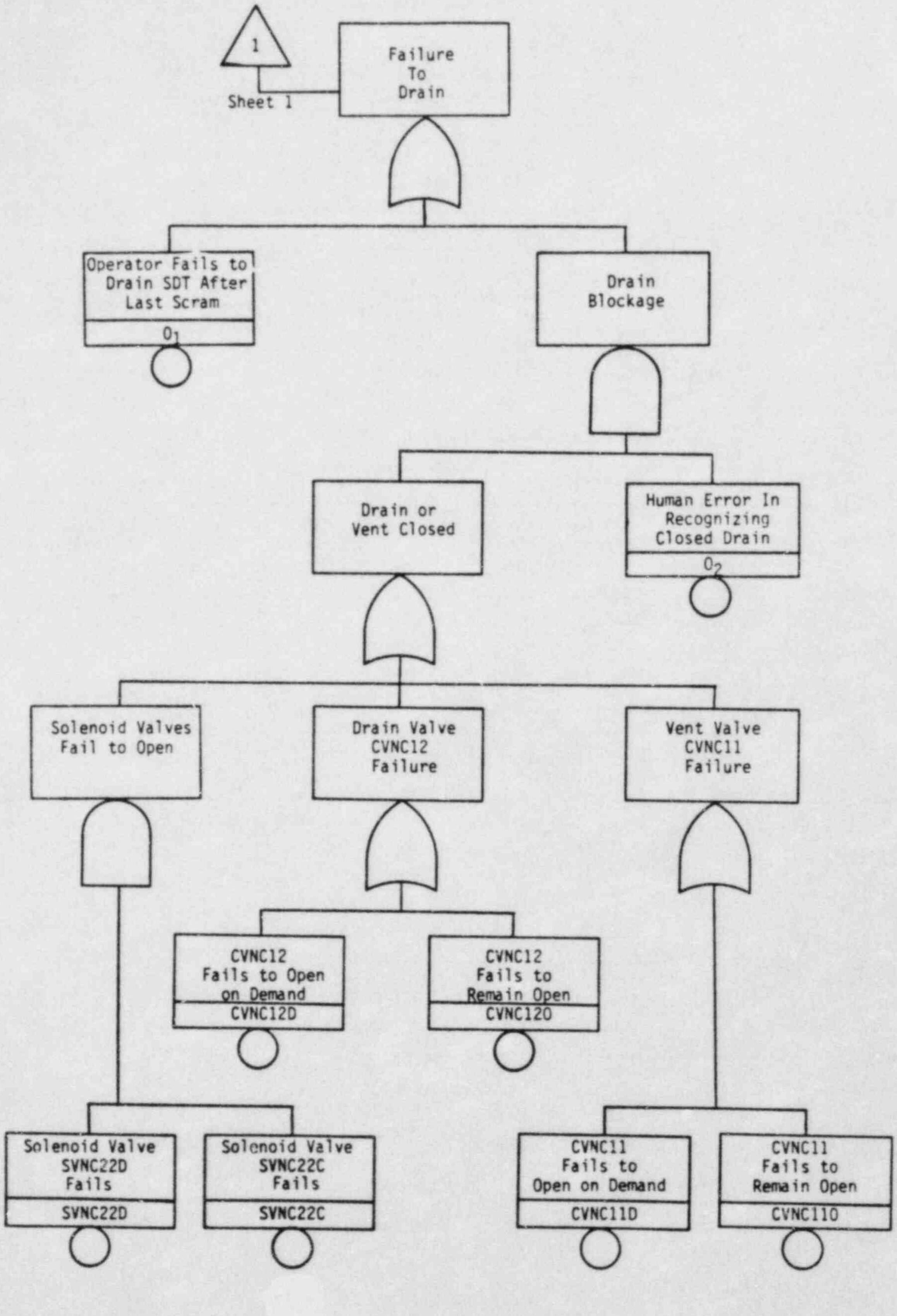

Figure 7.2 Sheet 2

(Continued)

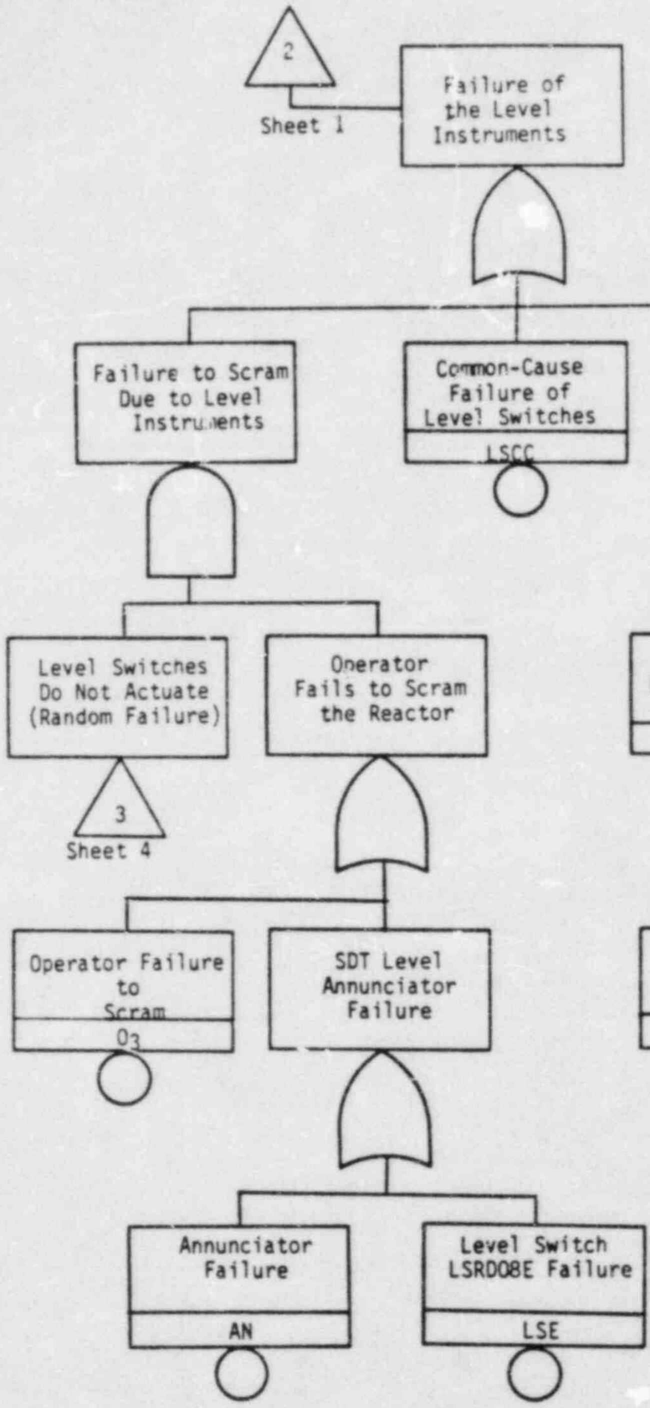

Figure 7.2

(Continued) Sheet 3

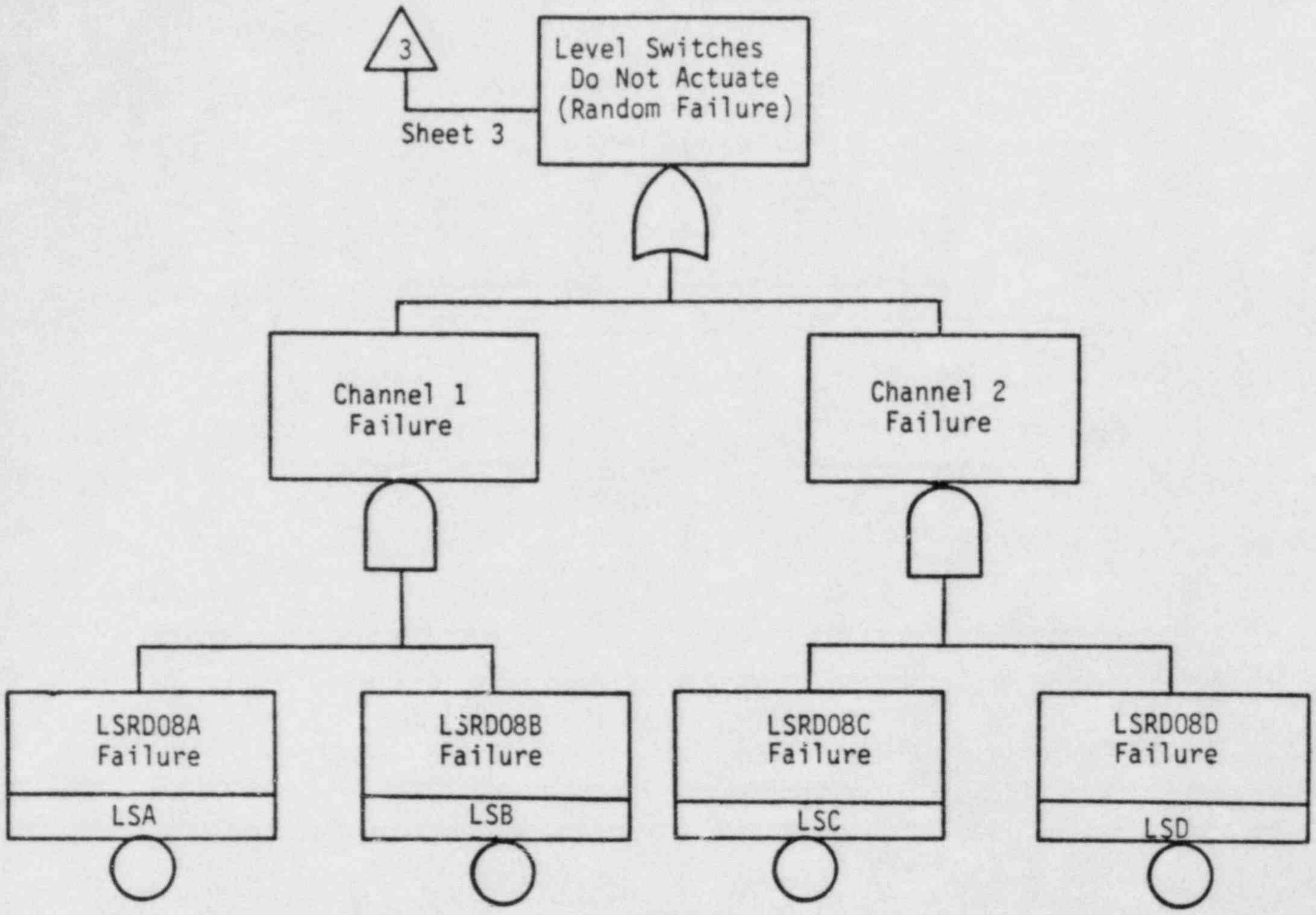

Figure 7.2

(Continued)

Table 7.1 Failure Rates for Various Faults Shown on Figure 7.2

Fault Identifier	Failure Mode Description	Failure Rate	Failure Duration (hours)	Unavailability	Comments
MS1	Multiple scram valve failure	7.6E-7/hr-valve	4380	1.11E-7	Assume at least three valve failures, BRP analysis
MS2	Single scram valve leakage	--	--	1.0	Assume a small leakage with probability of one, BRP analysis.
O_1	Operator fails to drain dump tank after last test or scram	--	--	2E-3	NUREG/CR-1278
SVNC22D, SVNC22C	Solenoid valves failure	2.7E-6/hr	720	1.0E-3	IREP Data
CVNC11D, CVNC12D	Drain valves fail to open on demand	1.0E-4/D	--	1.0E-4	IREP Data
CVNC11O, CVNC12O	Drain valves fail to remain open	2.7E-7/hr	360	1.0E-4	IREP Data

Table 7.1 Failure Rates for Various Faults Shown on Figure 7.2 (continued)

Fault Identifier	Failure Mode Description	Failure Rate	Failure Duration (hours)	Unavailability	Comments
O_2	Operator fails to recognize drain and vent closed	--	--	0.0123	See text.
O_3	Operator fails to respond to high dump tank alarm	--	--	1.4E-3	See text.
O_4	Human error leaving valves closed	--	--	1.0E-4	NUREG/CR-1278
VRD210, VRD220	Manual valves fail to remain open	1.0E-4	--	1.0E-4	IREP Data
LSA, B,C C,D,E	Level switch failure	2.0E-6	4380	8.76E-3	BRP analysis
LSCC	Common-cause failure of the level switches	--	--	8.76E-4	A β factor of 0.1 was used.
AN	Annunciator failure	1.4E-6/hr	8	5.6E-6	BRP analysis

The probability of human error consists of a basic human error E and a probability of nonrecovery R if a check is performed after the human action, i.e., P = ER. Note that if there are no checks between two tests, ($\overline{T} = \overline{d}$) the unavailability is equal to the probability of human error. If checks are performed between tests, the downtime $\overline{d}$ is the sum of the average downtime between the first test and all subsequent checks and can be found from the relationship $\overline{d} = h_1 + C_1h_2 + C_1h_2 + C_1C_2h_3 + \dots C_1C_2 \dots C_m\overline{T}$ where h_i (i = 1, 2 ... m) are the times between the first test and first, second and subsequent checks.

C_i (i = 1, 2 ... m) are the probabilities of non-detection at the first, second and subsequent checks. For the above case of monthly (720 hours) checks for a total of ten checks with an equal probability of non-detection of 0.1 the average downtime is:

$$\overline{d} = 720 + (0.1)\ 1440 + (0.1)^2\ 2160 + \dots$$
$$+ (0.1)^9\ 7200 = 889$$

Thus the unavailability is equal to:

$$\frac{(0.1)(889)}{(10)(720)} = 0.0123$$

For event O_3, the operator failure to respond to high dump tank alarm, the human error probability is calculated as (NUREG/CR-1278, Chapter 7)

$$\left[\frac{(2.2E\text{-}3)\ 19 + 1}{20}\right] (2.2E\text{-}3) = 1.14E\text{-}4$$

This probability is based on the action of two operators with low dependence. The basic human error of failing to respond to an annunciator and read an annunciator lamp is assumed to be 1.1E-3 with a factor of 2 for low or moderate level of stress.

Based on the failure rates shown in Table 7.1, the failure to scram due to high water level in the scram dump tank is equal to 2.3E-6. If the common-cause failure of the level switches is completely eliminated, the failure probability is reduced to 6.0E-7.

Assuming that the unavailability of the SDT due to high water level is a major contributor to the failure of the scram system, the reduction in the core melt frequency due to complete elimination of common-cause failure of the SDT level instruments is conservatively estimated as $\Delta F(cm)$ = (1.96)(2.3E-6 - 6.0E-7) = 3.3E-6/year where 1.96 is the frequency of occurrence for BRP transients used in the Big Rock Point PRA.

Based on the equation for reduction in exposure due to a reduction in core melt frequency discussed in Section II, the total reduction in exposure as a result of the above improvement is

Change in exposure	=	$\Delta F(cm)$(0.99)(1.2E+6)
	=	(3.3E-6)(0.99)(1.2E+6)
	=	3.9 man-rem/yr

The containment failure probability for transients sequences with a failure to scram is .99 since early containment failure is expected in ATWS sequences.

4. Conclusions

The contribution of the common-cause failure of the SDT level instrumentation to the unavailability of the SDT due to a high water level was calculated using a fault tree for the SDT and its associated piping and instrumentation. Complete elimination of the common-cause failure of the level instruments reduces the unavailability of the SDT from 2.3E-6 to 6.0E-7. Assuming that the unavailability of the SDT is a major contributor to the failure of the scram system, the change in core melt frequency is 3.3E-6/year, based on a transient frequency of 1.96/year. Based on the equation described in Section II resolution of this issue could reduce the population exposure by as much as 3.9 man-rem/yr.

Issue 8. Single Channel Reset

1. Introduction

On three occasions during the past five years the air operated scram valves, which open during a scram, have not completely closed prior to the partial opening of the scram dump tank (SDT) drain or vent valves when the reactor protection system has been reset. This situation leads to an open path from the primary coolant system to the drain and is essentially equivalent to a small LOCA. This licensee initiated issue is concerned about the contribution of this event to the initiation frequency of a small LOCA. Possible changes in the design of the scram system, that would introduce mitigating features for the prevention of such a LOCA, are considered in this issue.

2. Comments

None.

3. Analysis

Figure 8-1 shows the simplified schematic of the discharge portion of the scram system. During normal operation, the two air-operated valves CVNC11 and CVNC12 on the SDT are open to drain normal leakage of the water from the scram valves to the SDT. At the same time, the air operated valve CVNC10 is closed. When a scram is initiated air operated valve CVNC10 opens and air operated valves CVNC11 and CVNC12 close to allow insertion of the rods into the core and discharge of excess water to the SDT. Following the scram and before the reactor is taken to normal status the scram system is reset. The reset opens valves CVNC11 and CVNC12 to empty the SDT and closes valve CVNC10 to isolate the SDT from the primary coolant system. On three resets during the past five years valve CVNC10 partially closed and valves CVNC11 and CVNC12 partially opened creating a path from the primary coolant system to the drain system. All three cases were during refueling while the scram system was being tested. Consequently the primary coolant was at a low pressure and leakage of primary coolant through this path was lower than during normal operation. However there is no evidence to indicate that this is a shutdown phenomena only and calculations by the licensee indicate that

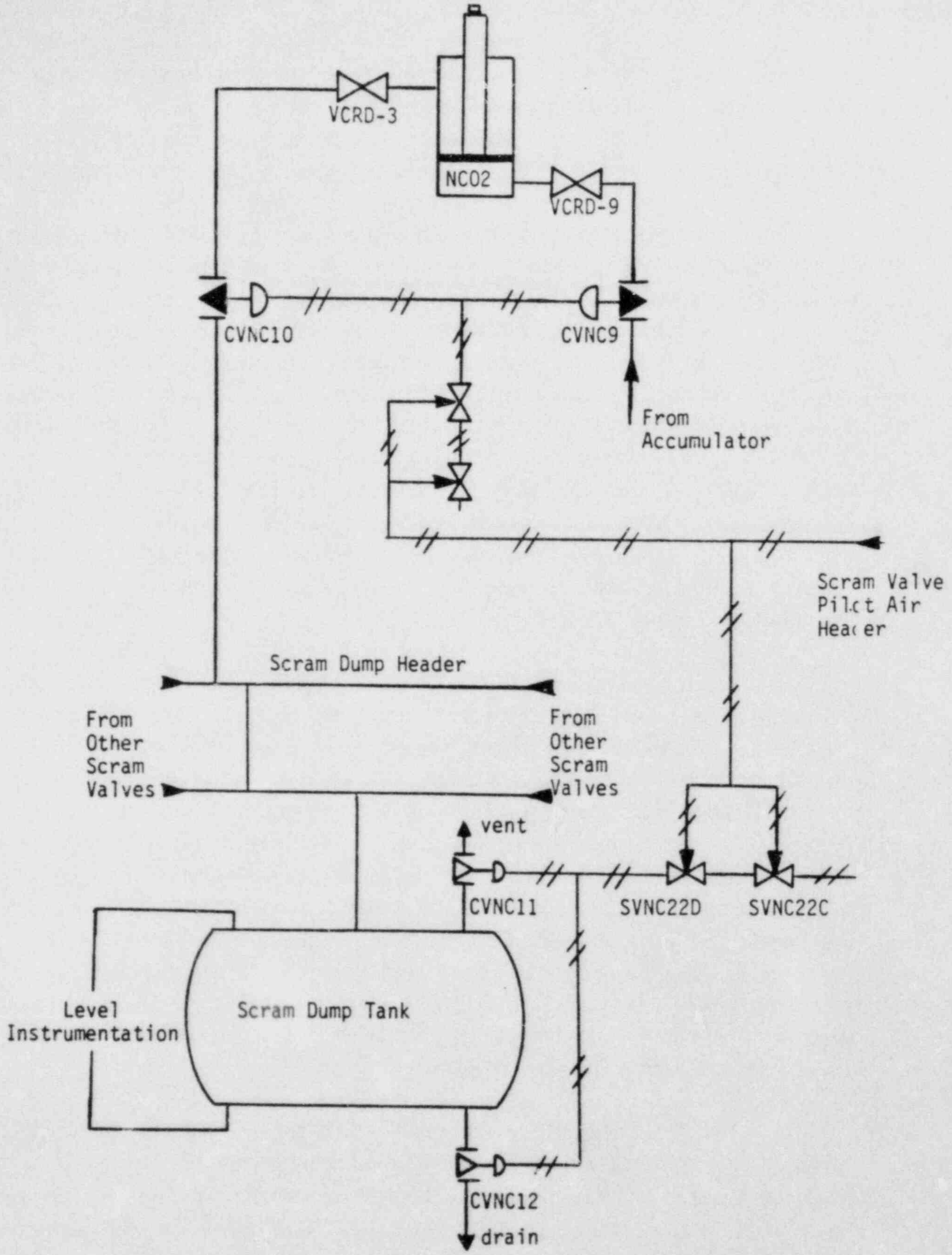

Figure 8.1 Simplified Schematic of the Discharge Portion of the Scram System

if this situation should occur during normal plant operation the leakage would be equivalent to a small LOCA. Although the exact cause of these partial valve operations is not known, it is believed that the problem may be associated with a lack of full pressure from the air supply system.

To compare this event with other types of small LOCA initiators its frequency of occurrence must be estimated. As was mentioned earlier this event has occurred three times over the past five years. The licensee has indicated that on the average the scram system is reset about ten times a year, including resets after an actual scram due to a transient during normal operation and scram tests during refueling. Thus, the frequency of occurrence of this event is approximately 0.06 per scram. For this analysis it will be assumed that there is one scram, at power, per year resulting in an S_1 LOCA frequency of .06/yr. Note that in the BRP PRA analysis, the frequency of initiation of a small LOCA, S_1, or small steam line break, S_3, is 10^{-3}/year. Thus, the frequency of initiation of a small LOCA due to partial failure of the air supply system dominates the overall frequency of initiation of a small LOCA.

Following a scram, the duration of the shutdown is dependent on the problem that initiated the scram. Even when the plant can be restored to an operating condition without repair, the plant is shut down for two shifts, i.e., approximately 16 hours. The operator will reset the scram system well before the plant is returned to power. Thus, there is sufficient time for the operator to notice the incorrect position of the air operated valves (SVNC22C, SVNC22D) based on the valve position indications available to him in the control room. The drain and vent valve positions are checked as part of the scram reset procedure. The probability of human error in failing to notice the incorrect valve positions following a scram reset is on the order of 1.0E-2 (NUREG/CR-1278, Table 20-15). This error probability results in a probability of an unisolated LOCA due to failure of the scram and vent valves of 6E-4/yr.

The frequency of a core melt due to this initiator can be calculated as the probability of the operator failing to notice and isolate this small LOCA times the failure probability of the systems designed to mitigate the consequences of a small LOCA. From the BRP PRA, the dominant core melt sequences initiated by a small LOCA are S_1E_mL and S_1E_mC. The first sequence consists of a small LOCA, S_1 with a frequency of 10^{-3}/yr followed by failure of the makeup to the emergency condenser, E_m, with a probability of 1.0 and failure of long term cooling, L, with a probability of 3.7E-2. The second sequence consists of a small LOCA, S_1 followed by failure of the makeup to the emergency condenser, E_m, and failure of the RDS/CS, C, with a probability of 4.0E-3. Thus, given a small LOCA the probability of failure of the mitigating systems is 4.1E-2. This leads to a core melt frequency of 2.5E-5/year [(6E-4/yr)(4.1E-1)] due to failure of the air operated valves.

There are several options available that would lower the frequency of initiation of a small LOCA due to failure of these valves. One option which the licensee is considering is to install two motor operated valves (MOVs) on the vent and drain lines of the SDT. In this case, if a leakage path exists through the SDT drain or vent lines the operator could close the MOVs to prevent a small LOCA. An alarmed flow meter on the SDT drain line would be required to indicate incomplete closure of valve CVNC10 and alert the operator that action must be taken. Installation of these two MOVs could have a slight impact on the reliability of the RPS. If either MOV should be left closed or fail closed the water level in the SDT will increase. If this increase in water level is not detected, either due to human error or instrumentation failures (see Issue 7), it could result in an RPS failure. However, the MOV failure is not expected to be a dominant cause of high SDT water level and it should be a negligible contributor to the RPS failure probability.

The frequency of initiation of a small LOCA in this new configuration is the product of the frequency of failure of air-operated valve CVNC10 to close (6E-4/year as calculated previously for the undetected failure to close) and the probability of the failure to isolate the drain line. Failure to isolate the drain line can be due to; a failure of the flow meter to indicate a large leakage; OR a failure of the operator to notice the alarm and close the MOVs; OR a failure of the MOV to close on demand. Failure of the flow meter, using an hourly failure rate of 2E-6/hour (IEEE - Std 500) and assuming a monthly test, is 7.2E-4. The probability of human error in responding to an alarmed display is on the order of 1.0E-3 (NUREG/CR-1278). The probability of an MOV failing on demand, assuming monthly testing, is 1.0E-3/demand.

Thus, the probability of core melt due to the above event after the addition of the motor operated valves is

$$(6E\text{-}4/year)(7.2E\text{-}4 + 1.0E\text{-}3 + 1.0E\text{-}3)(4.1E\text{-}2) = 6.69E\text{-}8/year.$$

The reduction in populational exposure due to the change in the core melt frequency, using the relationship discussed in Section II, is:

$$\begin{aligned} \text{Change in exposure} &= \Delta F(cm)(0.2)(1.2E+6) \\ &= (2.5E\text{-}5)(0.2)(1.2E+6) \\ &= 6 \text{ man-rem/yr.} \end{aligned}$$

For these LOCA sequences a containment failure probability of .2 has been used. This represents the normal containment failure probability consisting of the failure of the containment vent valves to close and the probability of leakage through the feedwater line.

4. Conclusions

The LOCA initiator addressed by this issue contributes to the dominant S_1 LOCA sequences at Big Rock Point. A LOCA frequency of 6E-4/yr was calculated for the unisolated LOCA initiated by leakage through the scram dump tank drain and vent lines. Using this LOCA frequency resolution of this issue results in a populational exposure reduction of 6 man-rem/yr.

Issue 11. Turbine Bypass Valve EHC System

1. Introduction

The Electro-Hydraulic Control (EHC) System for the turbine bypass valve at Big Rock Point has on occasion either spuriously opened or failed to open the turbine bypass valve. Spurious opening of the turbine bypass valve can be either a transient initiator or can, in conjunction with other failures, result in a failure to isolate the primary system. Failure of the turbine bypass valve to open causes the primary coolant system to lose its main heat sink. Values used in the Big Rock Point PRA for the two failure modes of the turbine bypass valve were

.14 = failure-to-open probability
.1/yr = frequency of spurious opening.

2. Comments

Details of the Big Rock Point EHC System design were not available, thus it was not possible to pinpoint the probable cause or causes of the relatively high failure rates for the EHC system-induced failures of the turbine bypass valve. However, it is possible to evaluate the potential benefit from increased reliability of the turbine bypass valve. It is this analysis which has been performed.

3. Analysis

The Big Rock Point PRA identified six dominant accident sequences initiated by a spurious opening of the turbine bypass valve. An additional four sequences involve a turbine bypass valve failure to open. These ten sequences, the sequence frequencies, and the associated containment failure probabilities (as given in the Big Rock Point PRA) are presented in Table 11-1.

To evaluate the potential benefit from improved EHC system reliability, these ten sequences were re-evaluated assuming a 50% reduction and an order of magnitude reduction in both the failure-to-open probability and

Table 11-1 Dominant Accident Sequences Affected by the Misoperation of the Turbine Bypass Valve

Accident Sequence	Sequence Frequency (yr^{-1})	Containment Leakage Probability[1] (given core melt)
BB_cE_vL	9.3E-7	.2
BB_cE_mL	3.3E-7	.2
BB_cE_vC	3.7E-7	.2
BB_cZY_fL	4.9E-5	.23
BB_cZY_fC	2.0E-5	.23
$T_2AB_oL_r$	3.2E-6	.99
$T_1AB_oL_r$	8.8E-7	.99
$T_3AB_oL_r$	7.8E-7	.99
$T_4AB_oL_r$	2.9E-7	.99
$T_5AB_oL_r$	2.9E-8	.99

A - RPS Failure
B - Turbine Bypass Valve - Spurious Opening
B_c - Failure of Turbine Bypass Valve to Reclose
B_o - Failure of Turbine Bypass/Main Condenser
C - Reactor Depressurization System/Core Spray System Failure
E_m - Failure of Makeup to the Emergency Condenser
E_v - Emergency Condenser Failure
L - Long Term Cooling Failure
L_r - Liquid Poison System Failure
T_1 - IPR/PR Failure
T_2 - Spurious Opening of Turbine Bypass Valve
T_3 - Loss of Feedwater
T_4 - Loss of One Feedwater Pump
T_5 - Load Rejection
Y_f - Feedwater System Failure
Z - MSIV Closure

[1]Containment leakage probability of
- .2 is the sum of vent valve failure to close probability and probability of leak path through steam line or feedwater line.
- .23 is the sum of the above two failure probabilities plus probability of failure to close MSIV.
- .99 is due to the expected overpressurization of the containment during an ATWS.

the spurious opening frequency. The results of these changes are shown in Table 11-2.

The reduction in the population exposure for each sequence is given by the equation presented in Section II. Using the data from Tables 11-1 and 11-2 the reduction in populational exposure, given a 50% reduction in the turbine bypass valve failure to open probability and spurious opening frequency, would be approximately 14 man-rem/yr. If an order of magnitude reduction in the turbine bypass valve failure probability is possible the reduction in populational exposure is approximately 26 man-rem/yr.

4. Conclusion

Since a specific problem with the EHC system for the turbine bypass valve was not identified and no specific recommendations regarding a possible fix are made an actual reduction in populational exposure was not calculated. Rather the potential reduction in populational exposure was calculated. It was assumed in the analysis that a reduction in EHC system unavailability is possible and that this reduction will reduce the failure-to-open probability and the spurious opening frequency for the turbine bypass valve. With these assumptions an order of magnitude reduction in the unreliability of the EHC system results in a 26 man-rem/yr reduction in the populational exposure. A 50% reduction in unreliability reduces populational exposure by 14 man-rem/yr.

Table 11-2 Potential Dominant Accident Frequency Reductions

Sequence[1]	F(B) (/yr)	$P(B_o)$	Sequence Frequency With Improvement in EHC (/yr)	Sequence Frequency Reduction (/yr)[2]
BB_cE_vL	.05		4.7E-7	4.7E-7
BB_cE_mL	.05		1.7E-7	1.7E-7
BB_cE_vC	.05		1.9E-7	1.9E-7
BB_cZY_fL	.05		2.5E-5	2.4E-5
BB_cZY_fC	.05		1.0E-5	1.0E-5
$T_2AB_oL_r$	.05	1.0[3]	1.6E-6	1.6E-6
$T_1AB_oL_r$		.07	4.4E-7	4.4E-7
$T_3AB_oL_r$		.07	3.9E-7	3.9E-7
$T_4AB_oL_r$		.07	1.5E-7	1.5E-7
$T_5AB_oL_r$		.07	1.5E-6	1.5E-6
BB_cE_vL	.01		9.3E-8	8.4E-7
BB_cE_mL	.01		3.3E-8	3.0E-7
BB_cE_vC	.01		3.7E-8	3.3E-7
BB_cZY_fL	.01		4.9E-6	4.4E-5
BB_cZY_fC	.01		2.0E-6	1.8E-5
$T_2AB_oL_r$	.01	1.0[3]	3.2E-7	2.9E-6
$T_1AB_oL_r$		.014	8.8E-8	7.9E-7
$T_3AB_oL_r$		.014	7.8E-8	7.0E-7
$T_4AB_oL_r$		.014	2.9E-8	2.6E-7
$T_5AB_oL_r$		.014	2.9E-7	2.6E-6

F(B) - Turbine bypass valve spurious opening frequency

$P(B_o)$ - Failure to open probability for turbine bypass valve

[1] See Table 11-1 for definition of sequence events.

[2] Sequence frequency reduction is the difference between the sequence frequency presented in Table 11-1 and the sequence frequency shown in this table.

[3] Value of 1.0 is used due to main condenser failure in this sequence.

Issue 17. PCS Isolation

1. Introduction

This is a utility-initiated issue. Eight of the primary coolant system drain and vent lines at Big Rock Point are currently isolated by a single manual valve on each line. Severe leakage through any one of these single valves would result in a small LOCA. The proposed modification is to add either a second valve or a pipe cap so that two isolation devices would have to fail to initiate a small LOCA.

2. Comments

A small LOCA caused by the loss of primary coolant through the eight vent and drain lines was evaluated in the Big Rock Point PRA as part of the interfacing systems LOCA analysis. In the PRA analysis a failure rate for severe valve leakage of 2.77E-8/hr was used. This is s'ightly larger than the WASH-1400 value, 1E-8/hr, and therefore will be used in this analysis.

3. Analysis

Using a value of 2.77E-8/hr for severe valve leakage the frequency of an interfacing system LOCA through any one of the eight drain or vent lines is:

$$F(I_\ell) = (8)(2.77E\text{-}8/hr)(8760\ hrs/yr) = 1.94E\text{-}3/yr$$

where

$F(I_\ell)$ = interfacing system LOCA frequency.

In the Big Rock Point PRA two dominant accident sequences are initiated by event I_ℓ:

$$I_\ell E_m L$$
$$I_\ell E_m C$$

where:

E_m = failure to supply makeup to the emergency condenser; $P(E_m) = 1.0$

L = failure of long term cooling; $P(L) = 4.2E-2$
C = failure of reactor depressurization system/core spray system; $P(C) = 4E-3$.

The failure probabilities quoted are from the Big Rock Point PRA. The expected core melt frequency, $F(CM_{I_\ell})$, of these two sequences, considering only the vent and drain valve failure contributions to I_ℓ, is

$$\begin{aligned} F(CM_{I_\ell}) &= F(I_\ell)P(E_m)P(L) + F(I_\ell)P(E_m)P(C) \\ &\quad (1.94E-3/yr)(1.0)(4.2E-2) + (1.94E-3/yr)(1.0)(4E-3) \\ &= 8.1E-5/yr + 7.8E-6/yr \\ &= 8.9E-5/yr. \end{aligned}$$

If a second isolation device is added to each of the eight vent and drain lines, the frequency of an interfacing system LOCA is reduced. Assuming that the isolation device is a manual valve tested annually for leakage, the probability of this second valve failing is

$$P_v = 1/2\ \lambda\ t$$

where

P_v = valve failure probability
λ = valve failure (leakage) rate = 2.77E-8/hr
t = test interval = 8760 hrs.

This results in a valve failure probability of 1.2E-4. The frequency of an interfacing system LOCA through one of these eight vent and drain lines is

$$\begin{aligned} F(I_\ell) &= 8\ (2.77E-8/hr \cdot 8760\ hrs/yr) \cdot P_v \\ &= 2.4E-7/yr. \end{aligned}$$

The expected core melt frequency from the two I_ℓ sequences due to LOCAs through the vent and drain lines would be reduced to:

$$\begin{aligned} F(CM_{I_\ell}) &= (2.4E-7/yr)(1.0)(4.2E-2) + (2.4E-7/yr)(1.0)(4E-3) \\ &= 1.1E-8/yr. \end{aligned}$$

The proposed modification yields a reduction in the core melt frequency of 8.9E-5/yr. This analysis did not consider operator errors, i.e., failure to reclose the valves after use. However, the human error probabilities associated with this operator error are expected to be very small. Additionally, these valves would not be used except during a shutdown, thus there would be a considerable chance for recovery before startup. Another consideration is that the addition of a redundant valve does not significantly affect the human error probabilities associated with leaving the valves open. For these reasons only mechanical failures were analyzed here.

The containment isolation failure probability associated with these two dominant accident sequences is .2 which is a combination of vent valve failure/leakage probability and the probability of leakage through the steam or feedwater line. The reduction in the populational exposure due to this proposed modification would be

$$(8.9\text{E-}5/\text{yr})(.2)(1.2\text{E+}6 \text{ man-rem/event})$$
$$= \quad 21 \text{ man-rem/yr}$$

using the relationship for populational exposure given in Section II of this report.

4. Conclusion

The installation of redundant manual valves or pipe caps in each of the eight primary coolant system vent and drain lines that currently have a single isolation device will result in a reduction of 21 man-rem/yr in the populational exposure. The use of pipe caps instead of redundant manual valves, should not significantly alter the reduction in populational exposure, provided that both the valve and the pipe cap are qualified as primary system isolation devices.

Issue 44. BS&B Valve Data

1. Introduction

At Big Rock Point air-operated valves (AOVs) are installed in many critical systems. An AOV may fail to function properly on demand due to an inadequate air supply to the valve. It is possible that the air pressures required to stroke the AOVs are greater than the normal air pressure in the Big Rock Point air supply pipes. Failure of an AOV in a critical system could affect the system failure probability and could be a contributing failure in dominant core-melt accident sequences. This issue was initially considered by BRP plant personnel and was subsequently presented to the NRC. Note that it has not been established at this time that this problem actually exists.

2. Comments

The failure being evaluated is a possible inadequate capacity of the air supply system while the system is operating as intended, i.e., there are no mechanical failures. Therefore, the failure probabilities assigned to the AOVs in this evaluation represent failures other than mechanical valve failures and air system mechanical failures.

The evaluation of the effects of an inadequate air supply to AOVs is limited to those systems that contribute to the dominant accident sequences of the Big Rock Point PRA. The following systems appear in dominant accident sequences in the Big Rock Point PRA and have at least one AOV:

1. main condenser system
2. feedwater system
3. condensate system
4. control rod drive system
5. demineralized water system
6. liquid poison system
7. main steam line system (Primary System Isolation)
8. containment isolation

Of these systems, a brief review and analysis has shown that the failure of AOVs due to loss/or inadequate air supply upon demand does not affect the failure probability of the main steam line and containment isolation systems (based on system failure probabilities used in the Big Rock Point PRA). The failure probability of the control rod drive system as a source of inventory makeup is also unaffected. The effect of inadequate air supplies to the RPS of which the control rod drive is a part, is part of the analysis for Issue 8 and is not repeated in this issue analysis.

There are four (4) AOVs in the main steam line which act as primary system isolation valves during shutdown or abnormal conditions. Upon air failure (or in the case of an inadequate air supply) these valves are designed to fail close. Thus the failed position of these valves is also the desired position during a demand, and therefore, their failure does not affect the system failure probability. (It is to be remembered that the failure of interest is failure of the primary system to isolate.) Similarly for the control rod drive system and the containment isolation system the failed position of the AOVs upon a loss of air is also the desired position during an abnormal event. Thus a failure of the AOVs has no significant impact on the system failure probability calculated in the Big Rock Point PRA.

To evaluate the effect of the AOVs loss of function (due to loss of/or inadequate air supply to the valve) on the remaining system failure probabilities, two assumptions were made: (1) the AOV function cannot be recovered after it fails (due to loss of air) and (2) the failure on demand probability for the AOV is .1. This failure probability was used in part because of the data available for the evaluation of issue 8 (Single Channel Reset). Operating data from Big Rock Point resulted in the use of a value of .06 for the failure probability for the AOVs in that issue. The air pressure problem analyzed in that issue appears to be similar to the problem evaluated in this issue. Due to uncertainties in the data, a value of .1 was used in this analysis rather than .06. It should be emphasized that the above assumptions are considered to be conservative. These assumptions are used here to illustrate the potential effect of the failure of AOVs if the air supply system at Big Rock Point is indeed inadequate.

The main condenser system, has six AOVs which, upon air failure, will fail to perform properly and will cause the main condenser to trip. Since the frequency of main condenser trips at Big Rock Point is not significantly different than the frequency of this trip at other nuclear power plants it is unlikely that failure of the AOVs due to an inadequate air supply system design has a significant effect on the main condenser failure frequency. However in response to a different transient initiator, the probability of failing the main condenser could be affected by the failure of these six air operated valves. The effects of air systems failures of the air-operated valves is analyzed in the following section of this issue analysis.

The same reasoning is applicable to the analysis of AOV's in the feedwater system. It is again concluded that loss of air does not significantly affect the accident initiating frequency of the feedwater system. For the feedwater system the system failure probability used in the Big Rock Point PRA is larger than the system failure probability attributable to air system failures of the AOVs. Therefore these failures do not significantly contribute to the system failure probability.

The Liquid Poison System (LPS) has two critical AOVs. The failed position (upon air failure) of one of these valves (CV-4020) is the desired position during abnormal events and therefore has no impact on the failure probability of the system. The remaining AOV does not fail in the safe mode as required during abnormal conditions, and its failure will affect the system reliability. Analysis shows that, to fail the system another component failure is required. The combined failure rate of these two events ($\sim 10^{-4}$/d) is negligible when compared to the system failure probability used in the Big Rock Point PRA (in the range of 10^{-2} to 1). It is therefore concluded that the effect of AOV failure on the LPS system failure probability is negligible.

The condensate system contains four AOVs of which three fail in the desired position. The remaining AOV, while contributing to condensate system failure can be dismissed since three other events must occur concurrently to fail the system. The estimated combined failure rate is insignificant when compared to other system failure modes.

The remaining system to be considered (the demineralized water system) does impact the system failure probability and the core damage frequency. The in-depth analysis for this system is presented in the next section.

3. Analysis

This section presents the analysis of the potential effects of AOV failures, due to an inadequate air supply, on the demineralized water system and the main condenser.

Demineralized Water System

The top event for the fault tree of the demineralized water system is "Insufficient make-up supply to the emergency condenser secondary inlet." (The fault tree is presented in the Big Rock Point PRA.) A review of the fault tree and the system P&ID shows that two AOVs are critical to the operation of the system: CV-4028 and CV-4105. Both valves are closed upon air failure, and closure of either one of these valves will lead to the event "insufficient supply from demineralized water." If the demand failure rate of these valves is estimated at 0.1 (assuming no recovery possible) then the failure rate of the event is 0.2. To fail the make-up water to the emergency condenser, both the demineralized water and the fire water systems must fail to supply make-up.

In the cutset analysis presented in the Big Rock Point PRA, the failure probability of the "no water from the fire water system" event was estimated at 0.1 for normal operation, given possible access to the containment. The failure probability of the event "failure to supply emergency condenser make-up" is approximately equal to the failure rate of the "insufficient supply from demineralized water" event (0.2) times that of the "no water from the fire water" event ($\sim$0.1) or:

$$E_m = 0.2 \times 0.1 = 0.02$$

where E_m is the probability of failure to supply make-up to the emergency condenser. This value will be used as the failure probability of the top event during normal operation.

In addition to the above case for normal plant conditions, the analysis shows the following cases represent the failure probability of the emergency condenser make-up during other than normal plant conditions.

	E_m: PRA Values	E_m Modified Values
Case 1: Normal Operation (Note: see above assumption)	1E-3	0.02
Case 2: No AC, operator fails to open VEC-1 (emergency condenser makeup valve from fire protection system) and demineralized water system pump is out	0.31	0.31

(Note: No change since the demineralized water pump is out, therefore the demineralized water system does not work regardless of the state of the valves.)

Case 3: LOCA, or No AC, and containment inaccessible (no change)	1.0	1.0
Case 4: Failure of emergency condenser make-up, given failure of demineralized water system and the fire water system.	0.08	0.14

(Note: The value used in the Big Rock Point PRA for the failure probability of the demineralized water system is 0.25, while this analysis shows a failure probability of 0.2 + 0.25 = 0.45.)

Case 5: Failure of emergency condenser make-up given failure of demineralized water system and emergency diesel failure to start.	0.19	0.22

(Note: Same as Case 4)

Given the above values for failure of the demineralized water system under various plant conditions, the new or modified values for the dominant sequences are then calculated and listed in Table 44-1.

The results show a difference of 3.2E-4/yr in the core damage frequency, which results in the following estimated population exposure,

(3.2E-4/yr)(0.2)(1.2E+6 man-rem/event) = 77 man-rem/yr.

The containment leakage probability associated with each sequence where the sequence frequency changed is 0.2. Containment leakage for these sequences is dominated by vent valve failure to close and leakage in the steam or feedwater lines.

Table 44-1. Dominant Sequences Affected by Failure of Demineralized Water System

Dominant Accident Sequences	Value Used for E_m BRP PRA	Value Used for E_m Modified	Sequence Frequency BRP PRA	Sequence Frequency Modified
ME_mNL	.001	.02	6.0E-7	1.2E-5
ME_mNC	.001	.02	2.4E-7	4.8E-6
PE_mF_sL	.08	.14	1.3E-5	2.3E-5
$PE_mF_sF_\ell L$	.08	.14	2.0E-6	3.5E-6
PE_mF_sC	.08	.14	1.3E-5	2.3E-5
PE_mF_sJ	.08	.14	4.8E-6	8.4E-6
PQE_mF_sL	.19	.22	6.7E-7	7.7E-7
PQE_mF_sC	.19	.22	2.5E-6	2.9E-6
S_1E_mL	1.0	1.0	3.7E-5	3.7E-5
$S1E_mC$	1.0	1.0	4.0E-6	4.0E-6
S_3E_mL	1.0	1.0	1.0E-5	1.0E-5
$S3E_mC$	1.0	1.0	4.0E-6	4.0E-6
UE_mUL	.31	.31	1.9E-5	1.9E-5
UE_mUC	.31	.31	7.4E-6	7.4E-6
UE_mUJ	.31	.31	5.7E-6	5.7E-6
WE_mL	.001	.02	6.0E-7	1.2E-5
WE_mC	.001	.02	2.4E-7	4.8E-5
BB_cE_mL	.001	.02	3.3E-7	6.6E-6
$I_\ell E_mL$	1.0	1.0	8.3E-5	8.3E-5
$I_\ell E_mC$	1.0	1.0	7.9E-6	7.9E-6
PE_mF_sKC	.08	.14	9.7E-5	1.7E-4
ME_mNKC	.001	.02	3.7E-6	7.4E-5
UE_mUKC	.31	.31	1.2E-4	1.2E-4
WE_mKC	.001	.02	3.7E-6	7.4E-5
Total			4.4E-4	7.6E-4

Event Code	Event
B	Spurious Opening of Turbine Bypass Valve
B_c	Failure of Bypass Valve/Main Condenser
C	RDS/Core Spray System Failure

Event Code	Event
E_m	Failure of Emergency Condenser Make-Up
E_v	Failure of Emergency Condenser Valves to Open
F_s	Failure to Restore Offsite Power (short term)
F_ℓ	Failure to Restore Offsite Power (long term)
I_ℓ	Interfacing System LOCA
J	Failure of Safety Valves to Open
K	Stuck Open Safety Valve
L	Failure of Long Term Cooling
M	Loss of Main Condenser
N	Failure to Restore Main Condenser
P	Loss of Offsite Power
Q	Failure of Emergency AC Power
S_1	Small LOCA
S_3	Small Stream Line Break
T	Turbine Trip
U	Loss of Instrument Air
W	Spurious Closure of MSIV

Main Condenser

There are only 2 dominant accident sequences where the AOV failure mode being analyzed will affect the main condenser failure probability. These two sequences are

TE_VNL with a frequency of 3.7E-7/yr and
TE_VNC with a frequency of 1.5E-7/yr.

(For a definition of the terms in the sequences see Table 44-1.) The value used for the failure to restore the main condenser in these two sequences is 9.4E-3. A value of 1.0 is used for this failure in all other Big Rock Point PRA dominant accident sequences. If the AOV failure probability of .1 is used for all six valves that can fail the main condenser, the system failure probability would be approximately 0.6. The two sequence frequencies would then be increased to 2.3E-5/yr for sequence TE_VNL, and 9.6E-6/yr for sequence TE_VNC. This is a change in the core melt frequency of 3.3E-5/yr. Using the relationship from Section II of this report and a containment failure probability of .2 for these two sequences (the containment failure for these two sequences is dominated by failure of the vent valves and steam line leakage), the change in populational exposure due to AOV-induced failures of the main condenser is

(3.3E-5/yr)(.2)(1.2E+6 man-rem/event)
= 8 man-rem/yr.

4. Conclusions

The objective of this issue is to evaluate the potential impact on the populational exposure due to improper functioning of air-operated valves upon loss of air pressure or inadequate air supply during normal air system operation. At Big Rock Point it is possible that the air supply system may not be supplying adequate air pressure to all AOVs even when the air system is apparently operating normally.

The results of the analysis are listed in Table 44-2. As shown by the tabulated results, no AOVs except those in the demineralized water

Table 44-2. Summarized System Impacts due to Failure of AOVs (upon loss of air)

	Systems	Effects on the Core Damage Frequency (/yr)	Populational Exposure Reduction (man-rem/yr)
1.	Main Condenser System	3.3E-5	8
2.	Feedwater System	none	none
3.	Condensate System	negligible	negligible
4.	Control Rod Drive System	none	none
5.	Demineralized Water System	3.2E-4	77
6.	Liquid Poison System	negligible	negligible
7.	Main Steam Line System	none	none
8.	Vent Valves System to Relieve Vacuum	none	none
9.	Containment Isolation	none	none

system and the main condenser system, have a significant effect on their associated systems.

Although the results show a rather large difference in the population exposure for the demineralized water system (between the PRA and the new values), the consequent reduction is meant as an upper bound on the potential reduction. The problem requires further analysis to determine whether the failure mode under consideration actually exists at the Big Rock Point plant.

Issue 50E. Containment Airlock

1. Introduction

At Big Rock Point the three sets of airlock door seals are currently tested every 6 months. Appendix J of 10 CFR 50 requires that the containment airlocks be tested after every entry or every 72 hours during periods of frequent use, as is the case at Big Rock Point.

The risk significance of this issue relates to the probability of containment isolation failure. More frequent testing of the airlock would reduce the length of time a failed airlock would present a containment leakage path.

2. Comments

The testing history of the airlock door seals at Big Rock Point indicate that in twenty years, since April of 1963, no door seal has failed a test.

3. Analysis

Of the three airlocks at Big Rock Point two (the equipment and personnel airlocks) have been in operation for about 20 years. The third (the escape airlock) has been in operation for about six years. Each airlock is tested once every six months. Each airlock test is essentially a test of two door seals (the inner and outer door seals). Thus, there are a total of:

20 yrs operation x 2 airlocks + 6 years operation x 1 airlock
= 46 airlock-years experience.

Since each airlock has two door seals there are:

2 seals/airlock x 46 airlock-years
= 92 seal-years of experience without a failure.

These 92 seal-years experience translate to approximately 800,000 seal-hours of experience without a failure. A Chi-squared distribution upper bound approximation of the door seal failure rate can be obtained using the expression:

$$\lambda = \frac{\chi^2_{f;.95}}{2T}$$

where:

$\chi^2_{f;.95}$	=	the Chi-square value with f degrees of freedom, at the 95th percentile level
T	=	the total seal-hours of experience (= 800,000 hours)
λ	=	door seal failure rate.

The degrees of freedom for Chi-square is given by the expression

$$f = 2(n+1),$$

where n = the number of failures experienced. In this case n=0, and therefore f=2. Therefore, the value of χ^2 is:

$$\chi^2_{f;.95} = 5.991,$$

and the upper bound failure rate estimate is:

$$\begin{aligned} \lambda &= 5.991/(2)(800,000) \\ &= 3.7E\text{-}6/hr \end{aligned}$$

The interpretation of this upper bound failure rate estimate is that the data do not support the contention that the door seal failure rate is larger than 3.7E-6, with a 95% confidence.

The average unavailability of a single door seal (unavailable to prevent a leak) is given by

$$P = 1/2\ \lambda\ t$$

where

t = test interval

P = door seal failure probability (unavailability).

Assuming test intervals of 6 months and 72 hours, the leakage probability for the door seal is 7.9E-3 and 1.3E-4 respectively.

Since there are three air locks at Big Rock Point each of which has two seals, the associated probability of a leakage path through any air locks is

$$3P^2.$$

Again assuming testing intervals of 6 months and 72 hours, the probability of one of these leakage paths existing is 1.8E-4 and 5E-8 respectively.

The core melt frequency for the Big Rock Point Plant, as given in the utility PRA, is 9.75E-4. Using the equation for populational exposure, from Section II, this leakage path contributes

(9.75E-4/yr)(2E-4)(1.2E+6 man-rem/yr)

= 2E-1 man-rem/yr

if the air lock door seals are tested every 6 months. Even if the door seal leakage path probability is reduced to 0.0 it would result in a reduction in populational exposure of no more than 2E-1 man-rem/yr.

4. Conclusion

Leakage through the door seals, probability of leakage = 2E-4, makes a negligible contribution to the containment leakage probability which is on the order of 2E-1. The increased testing of the containment airlock door seals leads to a reduction in the populational exposure of less than a 2E-1 man-rem/yr.

Issue 63. Containment Purging

1. Introduction

The concern represented by this NRC-initiated (NRC letter dated September 14, 1982) issue is that in the event of a LOCA and subsequent pressurization of the containment, debris from inside the containment could be transmitted into the ventilation ductwork. Such debris could interfere with the closure of the ventilation valves and prohibit containment isolation. Installation of a debris screen over the ventilation intake for each of the valves is a proposed resolution for this issue.

2. Comments

Since debris induced failure of the containment vent valves was not considered in the Big Rock Point PRA, the failure probability for this event had to be estimated and a parametric analysis performed. Cases were examined for 100%, 50% and 1% increases in the unavailability of the ventilation valves for containment isolation. An estimate was also made of the decrease in failures attributable to the installation of screens over the ventilation intakes. Screen installation was credited with a 100-fold improvement in the debris related failure probability of the valves.

Other possible modifications to reduce the containment leakage probability (failure to isolate/leakage is the dominant containment failure mode) for Big Rock Point are evaluated as part of this analysis. Proposed modifications include increased testing of the containment vent valves (reduction of the test interval from 18 months to 6 months) and limited purging of the containment. The Big Rock Point containment is currently constantly purged. The proposed modification is to limit purging to 90 hours per year, if possible.

3. Analysis

The Big Rock Point dominant accident sequences that contain vent valve failure as a containment failure mode occur with a frequency of 7.14E-4/yr. The only sequences this does not include are: ATWS sequences (the containment fails due to overpressurization), fire-initiated sequences and sequences where the MSIV fails to close as part of the sequence (and thus containment integrity is lost).

Debris Screens

The frequency of a release due to these dominant accident sequences and a vent valve failure (failure probability equal to .13) is 9.3E-5/yr. This frequency is a significant fraction of the Big Rock Point release frequency for category BRP-3 due to these sequences. The total release frequency for BRP-3 due to these sequences is 1.49E-4/yr. The additional release frequency is due primarily to failure to isolate the steam/feedwater lines.

Table 63-1 presents the release frequencies associated with these dominant accident sequences with vent valve failures as the containment failure mode. The vent valve failure probabilities represent the base case of vent failures (no failure contribution due to debris), and modified cases where debris induced failures contribute an additional 100%, 50% and 1% to the vent valve failure probability. These four cases are evaluated with and without debris screens. Using the relationship from Section II the worst case calculated, 100% additional contribution to the vent valve failure probability, yields a 111 man-rem/yr change in the populational exposure. The results for all cases evaluated are presented in Table 63-2.

Increased Testing

Reducing the test interval from 18 months to 6 months will reduce the failure to close probability for the vent valves and the vent valve unavailability due to leakage. In the vent valve design modeled in the Big Rock Point PRA failure of any one of the four solenoid valves that control the vent valves will cause a failure of the vent valves to close. A path to the environment will exist if both inlet or both outlet vent valves fail to close. Therefore, the failure to close probability for the vent valves can be represented by

$$P(VFC) = P(S_1)+P(S_2)+P(S_3)+P(S_4)+P(V_1)P(V_2)+P(V_3)P(V_4)$$

where

Table 63-1 BRP-3 Release Frequency (per year) Resulting From Ventilation Valve Failure Only

	Base Case	Plus 100% for valve failure due to debris interference	Plus 50% for valve failure due to debris interference	Plus 1% for valve failure due to debris interference
without screens	9.3E-5	1.9E-4	1.4E-4	9.4E-5
with screens+	9.3E-5	9.4E-5	9.3E-5	9.3E-5

+Assumes debris screens reduce interference with valve closure by factor of 100.

Table 63-2 Benefit Due to the Installation of Debris Screens on the Containment Ventilation Ducts. (Man-Rems)

	Base Case	Plus 100% due to debris interference	Plus 50% due to debris interference	Plus 1% due to debris interference
without screens	1.1E+2	223	167	113
with screens	1.1E+2	112	111	111
Person-rem Reduction		111	56	2

$P(VFC)$ = probability of containment leakage due to the vent valves failure to close

$P(S_n)$;n=1,2,3,4 = probability that a solenoid valve fails

$P(V_n)$;n=1,2,3,4 = probability that a vent valve fails to close.

The values used in the Big Rock Point PRA for these two types of failure are:

$$P(S_n) = .02/d$$
$$P(V_n) = .0837/d.$$

and result in a value of .096 for P(VFC).

The failure probability for a component can be calculated using the following relationship

$$P(S) = 1/2\ \lambda\ t$$

where

λ = failure rate

t = test interval.

From this relationship it is obvious that if the test interval is reduced by a factor of three, from 18 months to 6 months, the failure probability is also reduced by a factor of 3. Therefore with a 6 month test interval the failure probabilities for the solenoid valves and the vent valves become:

$$P(S_n) = .0067/\text{demand}$$
$$P(V_n) = .0279/\text{demand}.$$

The probability of containment leakage due to the vent valves failure to close is:

$$P(VFC) = .0067+.0067+.0067+.0067+(.0279)(.0279)+(.0279)(.0279)$$
$$= .028/\text{demand}.$$

Leakage through the vent valves occurs with a probability of .03

per demand. Using the argument developed for the failure to close probability, increased testing of the vent valve should reduce this failure probability by a factor of 3, to .01 per demand.

The change in the containment leakage probability due to the increased testing of the containment vent valves is the sum of the reduction in the vent valves failure to close probability and the reduction in the vent valve leakage probability. The sum of these reductions is .088/demand.

Using the relationship in Section II, this reduction yields a drop in the populational exposure of

$$(7.14E\text{-}4/yr)(.088)(1.2E{+}6\ \text{man-rem/event})$$
$$= 75\ \text{man-rem/yr}.$$

Limited Purging

It has been proposed that the purging of the Big Rock Point containment be limited to 90 hours a year. It is assumed here that limited purging is possible. (Big Rock Point was designed to have continuous purging. Operation of the plant with limited purging may or may not be feasible.)

Limiting the time during which the Big Rock Point containment is purged would affect the vent valve failure to close probability but would not affect the vent valve leakage probability. With purging limited to 90 hours per year the fraction of time the vent valves would have to close during an accident would be:

$$\frac{90\ \text{hrs}}{8760\ \text{hrs}} = .01$$

Therefore the probability of containment leakage due to vent valve failure to close would be

$$.01\ P(VFC)$$
$$= (.01)(.096)$$
$$= 9.6E\text{-}4/\text{demand}.$$

This is a reduction of .095 per demand from the case of continuous purging. Using the relationship in Section II, this results in a reduction in the populational exposure of

$$(7.14E\text{-}4/yr)(.095)(1.2E{+}6 \text{ man-rem/event})$$
$$= 81 \text{ man-rem/yr.}$$

Increased Testing and Limited Purging

If both increased testing and limited purging are required at Big Rock Point the reduction in the containment failure probability can be calculated in two steps. First the benefit to be derived from increased testing can be calculated. This has been done and the probability of the vent valves failing to close was reduced from .096 to .028 and the vent valve leakage probability was reduced from .03 to .01. (See the Increased Testing portion of this analysis for details.)

Limited purging will affect only the new vent valve failure to close probability. For this case the limited purging will reduce this probability to:

$$.01\ P(VFC)$$
$$= (.01)(.028)$$
$$= 2.8E\text{-}4$$

The probability of a leakage path through the vent valves is reduced to .01 due to the increased testing and limited purging. This is a reduction of .116 in the containment leakage probability and results in a reduction in the populational exposure of:

$$(7.14E\text{-}4/yr)(.116)(1.2E{+}6 \text{ man-rem/yr})$$
$$= 99 \text{ man-rem/yr}$$

based on the relationship presented in Section II.

4. Conclusions

Based on the assumptions stated in this analysis, Table 63-2 lists the benefit which can be achieved through the installation of debris screens on the containment ventilation ducts. From the event frequencies generated on Table 63-1 and using the equation from Section II the populational exposures for all three cases were calculated. The worst case evaluated, a 100% increase in the vent valve failure to close probability, increases populational exposure by 111 man-rem/yr. Avoidance of this exposure represents the potential benefit to be derived from the installation of debris screens. The populational exposures for all cases are presented in Table 63-2.

The effects of limited purging and increased testing of the containment vent valves were analyzed also. Limiting purging to 90 hours a year results in an 81 man-rem/yr reduction in the population exposure. Testing the vent valves every 6 months (rather than 18) results in a 75 man-rem/yr reduction in the populational exposure. Doing both results in a 99 man-rem/yr reduction.

If debris screens are installed, vent valve testing is increased and only limited purging is allowed there is a potential for a 210 man-rem/yr reduction in the populational exposure.

Issue 73 Control of Heavy Loads

1. Introduction

Generic Technical Activity Task A-36 was established to systematically examine staff licensing criteria and the adequacy of measures in effect at operating nuclear power plants to assure the safe handling of heavy loads and to recommend necessary changes to these measures. Many of the changes recommended* had to do with procedures, training, equipment inspection, and other similar non-hardware oriented items. These items have, in most cases, been implemented or will be implemented at Big Rock Point. One of the recommendations did deal with the installation of additional equipment in the form of mechanical stops or electrical interlocks. The purpose would be to prevent crane travel over fuel elements or shutdown-related systems. If it is impossible to prevent travel over these equipment, the stops or interlocks should be used to minimize travel over these areas.

2. Comments

Lack of certain specific information makes it possible to perform only a crude bounding analysis for this issue. The information available includes an outline of the path of each load through the plant, in terms of selected "plant areas," for the reactor crane, emergency condenser beam, cleanup hoist, RDS hoist, SRV hoist, and turbine crane. Of these, the RDS and SRV hoists are not used during power operation and do not pass over any fuel, thus are not included in the analysis. The analysis assumes that only two types of accidents are important: (1) a crane failure during power operation that results in a system failure; and (2) a crane failure at any time that results in fuel failure. A Franklin Research Center report**

*All recommendations from NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants.

**"Control of Heavy Loads (C-10): Consumers Power Company Big Rock Point Nuclear Plant," Technical Evaluation Report TER-C5257-440 (Draft), Franklin Research Center, June 3, 1982.

stated that the screen house trolley and equipment lock crane should be included as potentially important; however, information was not available about these lifts at the level of detail of those mentioned previously. Thus they could not be included in the analysis. In addition to the path of each given load through these plant areas, the information available provided a list of systems in each area. In some cases, the number of load transfers for a given crane was also available. All specific information was taken from utility letters to the NRC dated July 1, 1981 and September 23, 1981.

3. Analysis

To perform the analysis, it is to necessary to estimate the probability of a heavy load drop on various plant systems and fuel. Because of information limitations only a crude estimate is possible. Conservative assumptions used for this analysis are:

- o Each load transfer takes one hour
- o The suspended load spends an equal amount of time in each plant area it passes through. (The plant areas are shown in Figure 73-1.)
- o The suspended load spends an equal amount of time over each sensitive system in a given area.
- o The load is always over a sensitive system, given that an error has been made by the crane operator in following the correct path; this implies that the operator never makes a partial error (e.g., passing over one system) but rather makes a total error (e.g., totally deviates from the safe path and passes over all sensitive systems).
- o It is possible to develop a load path that avoids all sensitive systems.
- o A dropped load will always cause a failure.

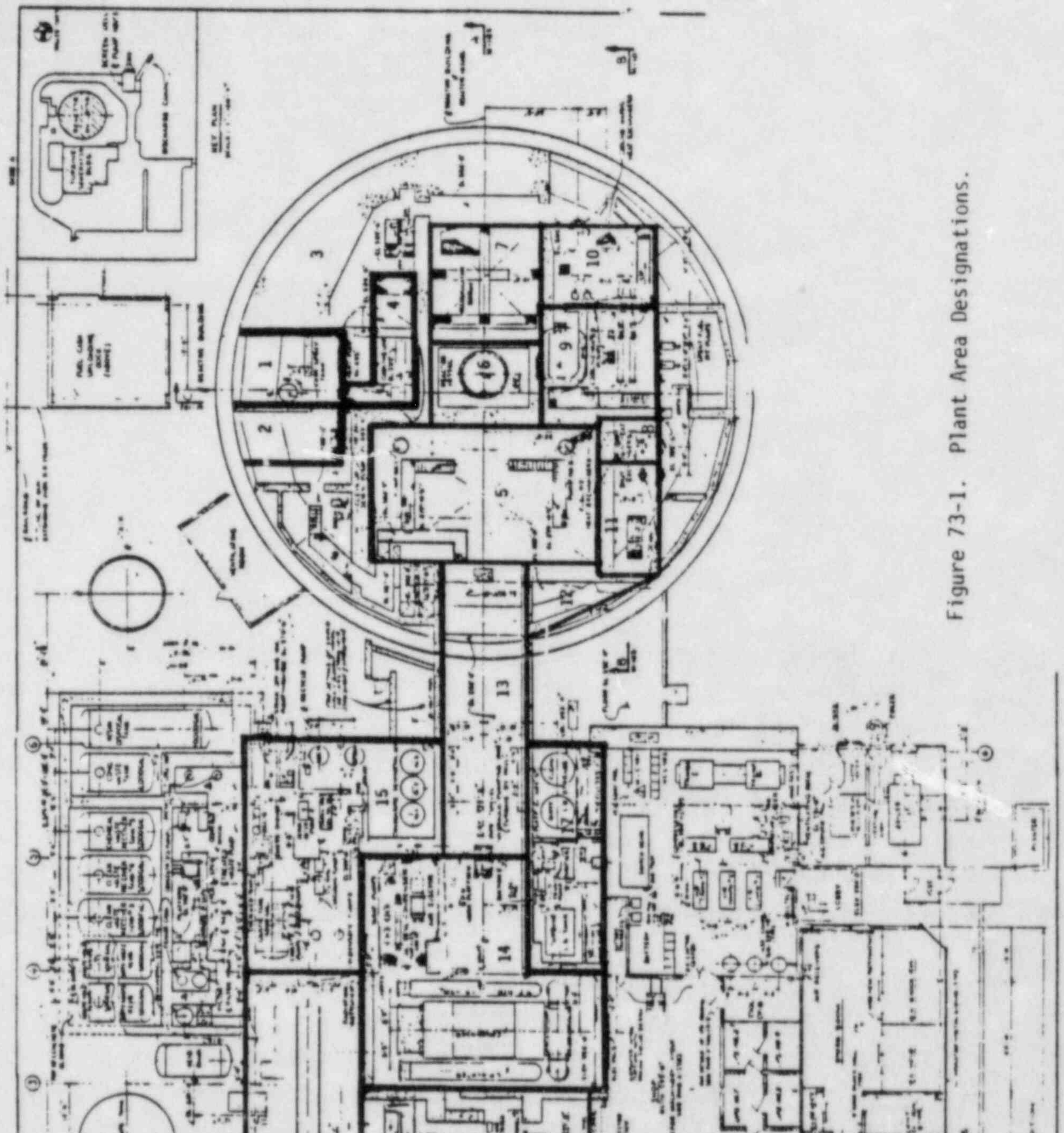

Figure 73-1. Plant Area Designations.

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The frequency of system damage can thus be represented as

$$F_s = P_h \times T_s \times \lambda_o$$

where:

P_h = probability of operator error (operator does not follow "hazardless" load path) = .01 (conservative bounding value)*

T_s = total time (hours per year) that a load could spend over a particular system "s", given the operator error noted above.

λ_o = operating failure rate of a lifting device (load drop) = 3E-6/hr**

The first step in the analysis is to compile and summarize the loads transferred, the paths over which they are transferred, and the systems affected. This is shown on Table 73-1. The loads are divided into load groups that follow similar transfer paths. The areas through which each load group passes are indicated by the "x-outs" under each respective load group column. The systems affected are also indicated, with the plant area(s) they appear in noted in the appropriate row. This table allows one to determine the path of the loads in a given load group and the affected systems.

The next step is to determine how many loads are transferred each year in each load group. For the 7 load groups in containment, we know from utility-supplied information that approximately 100 transfers take place. Forty of these are definitely in load group RC1 and ten others in load group RC2. The remaining fifty are indicated as miscellaneous and, for lack of better information, are assumed to be equally divided between the 7 load

*Screening value used in Interim Reliability Evaluation Program (IREP).
**From WASH-1400 and Big Rock Point PRA.

Table 73-1. Summary of Load Paths and Affected Systems

Area #, Systems	Load Group: Reactor Crane 1	Reactor Crane 2	Reactor Crane 3	Reactor Crane 4	Reactor Crane 5	E.C. Beam	Cleanup Hoist	Turbine Crane
1	X	X	X					
2	X	X	X	X			X	
3								
4		X	X					
5	X	X	X	X	X	X		
6	X	X	X	X	X			
7	X	X		X				
8		X			X	X		
9	X	X		X				
10		X						
11								
12								
13								X
14								X
15								X
16								X
17								X
18								X
	RVI-6	RVI-6	RVI-6	RVI-6	RVI-6			SPS-16,17,LOS-17 T/G-14, MCS-14
CDS								14,15
CIS	1,5,9	1,4,5,8,9,10	1,4,5	5,9	5,8	5,8		13
CRD	5,6,7,9	5,6,7,9,10	5,6	5,6,7,9	5,6	5		13,14,15
CWS								14
DMW	5,9	5,9,10	5	5,9	5	5		13,15
ECS								
FHS								
FPS	1,2,5,6	1,2,4,5,6	1,2,4,5,6		2,5,6	5,6	2	13,15,16,17,18
FWS								13
LPS	5	5	5	5	5	5		
MSS	5	5	5	5	5	5		13,14
PCS	2,5,6,7	2,4,5,6,7,8	2,4,5,6	2,5,6,7	5,6,8	5,8	2	13
PIS	1,2,5	1,2,5	1,2,5	2,5	5	5	2	
RCS	2	2	2	2			2	
RCW	5,6,9	4,5,6,8,9,10	4,5,6	5,6,9	5,6,8	5,8		
RDS								
RPS	5,6,9	5,6,9,10	5,6	5,6,9	5,6	5		14
SCS								
SFP	9	8,9,10		9	8	8		
SWS	5,9	4,5,8,9,10	4,5	5,9	5	5,8		13,15,16

RC1 LOADS - TII Cask, Cobalt Cask, Waste & Debris Casks, Misc Fuel, R&D tools, Spent Fuel Cask
RC2 LOADS - Load Blocks, Fuel Xfer Cask, Vessel Head Stand, Filter Sock Cask, Spent Fuel Storage Racks
RC3 LOADS - Vessel Head Insul., Shield Plug, Vessel Head, Fuel Shipping Cont., Recirc Pumps
RC4 LOADS - Stud Tensioner, Core Spray Line Shield, ISI Insp Dev, Vessel Serv Plot, Misc. Internals
RC5 LOADS - CAMS, Core Spray Line, RCP Hatches
E.C. BEAM LOADS - Misc.
C-UH LOADS - Demin Plug
T.C. LOADS - Exciter, Casings, Cond. Pump Components Feed Pump Components, Turbine Hatches

groups. To be conservative, we assign 8 transfers to each load group. No information is provided regarding the number of turbine building transfers, so a parametric analysis using 10, 30 and 100 transfers is performed. Table 73-2 shows the numbers of transfers used in this analysis.

Using the assumptions regarding overall transfer time the fraction of time in an area, the fraction of time over a particular system, and the total number of transfers per load group, the total time a system is "at risk" from each load group is shown in Tables 73-3.a through 73-3.h. The absolute total for each system is shown in Table 73-4.

The "at risk" times calculated above assume that the operator has made an error that caused him to carry the load over these sensitive systems. It was mentioned in the assumptions that it is possible to have paths for each load that would avoid all risks. This assumption gives a maximum bound for the value of installing the interlocks, even though such paths probably do not exist. To convert the "at risk" times to system damage frequencies the "at risk" times are multiplied by the probability of operator error and the failure rate of a lifting device, as shown in the equation at the beginning of this section. The results of this calculation for each system are shown on Table 73-5. The values calculated for the various systems show that system damage due to heavy load drop is a very infrequent event. The total over all systems is shown at the bottom of the table. In some ways, this number is meaningless because the effect (on consequences) of a heavy load drop on each particular system is different. Some events will bring the plant closer to core melt than others. However, even if <u>every</u> heavy load drop led directly to core melt, the total change in core melt frequency from eliminating all these events by installing interlocks would be unmeasurable when compared to overall core melt frequency. The same would be true of overall risk, even using the maximum case of 100 turbine crane transfers per year. We definitely know, however, that every heavy load drop <u>does</u> <u>not</u> lead directly to core melt; other failures or events are required. Also, this analysis gives maximum credit for the interlocks by assuming that a perfectly safe transfer path exists for each lifting device, i.e., one which does not have to pass over any sensitive systems. We know this is not the case, and thus the frequency of system damage due to load drop (without the interlocks) is actually higher than the values calculated. Additionally, much of it is non-reducible. For example,

Table 73-2 Number of Transfers Per Load Group

Load Group	No. of Transfers
Reactor Crane 1	48
Reactor Crane 2	18
Reactor Crane 3	8
Reactor Crane 4	8
Reactor Crane 5	8
Emergency Condenser Beam	8
Cleanup Hoist	8
Turbine Crane	10, 30, 100

Table 73-3.a System "At Risk" Times
Reactor Crane Load Group 1

48 Transfers per year
6 Areas affected per transfer
∴ .17 Hours in each area per transfer

Area 1 has 3 systems - .057 hours over each system
Area 2 has 4 systems - .043 hours over each system
Area 5 has 11 systems - .015 hours over each system
Area 6 has 6 systems - .028 hours over each system
Area 7 has 2 systems - .085 hours over each system
Area 9 has 7 systems - .024 hours over each system

Area/ System	1	2	5	6	7	9	Total Time Per Transfer	Total Time Per Year
CIS	.057		.015			.024	.096	4.6
CRD			.015	.028	.085	.024	.15	7.2
DMW			.015			.024	.039	1.9
FPS	.057	.043	.015	.028			.14	6.7
LPS			.015				.015	.72
MSS			.015				.015	.72
PCS		.043	.015	.028	.085		.17	8.2
PIS	.057	.043	.015				.12	5.8
RCS		.043					.043	2.1
RCW			.015	.028		.024	.067	3.2
RPS			.015	.028		.024	.067	3.2
SFP						.024	.024	1.2
SWS			.015			.024	.039	1.9
RVI				.028			.028	1.3

Table 73-3.b System "At Risk" Times
Reactor Crane Load Group 2

18 Transfers per year
9 Areas affected per transfer
∴ .11 Hours in each area per transfer

Area 1 has 3 systems - .037 hours over each system
Area 2 has 4 systems - .028 hours over each system
Area 4 has 5 systems - .022 hours over each system
Area 5 has 11 systems - .01 hours over each system
Area 6 has 6 systems - .018 hours over each system
Area 7 has 2 systems - .055 hours over each system
Area 8 has 5 systems - .022 hours over each system
Area 9 has 7 systems - .016 hours over each system
Area 10 has 7 systems - .016 hours over each system

Area/ System	1	2	4	5	6	7	8	9	10	Total Time Per Transfer	Total Time Per Year
CIS	.037		.022	.01			.022	.016	.016	.12	2.2
CRD				.01	.018	.055		.016	.016	.12	2.2
DMW				.01				.016	.016	.042	.76
FPS	.037	.028	.022	.01	.018					.12	2.2
LPS				.01						.01	.18
MSS				.01						.01	.18
PCS		.028	.022	.01	.018	.055	.022			.16	2.9
PIS	.037	.028		.01						.075	1.4
RCS		.028								.028	.50
RCW			.022	.01	.018		.022	.016	.016	.10	1.8
RPS				.01	.018			.016	.016	.06	1.1
SFP							.022	.016	.016	.054	.97
SWS			.022	.01			.022	.016	.016	.086	1.5
RVI					.018					.018	.32

Table 73-3.c System "At Risk" Times
Reactor Crane Load Group 3

8 Transfers per year
5 Areas affected per transfer
.·. .20 Hours in each area per transfer

Area 1 has 3 systems - .067 hours over each system
Area 2 has 4 systems - .05 hours over each system
Area 4 has 5 systems - .04 hours over each system
Area 5 has 11 systems - .018 hours over each system
Area 6 has 6 systems - .033 hours over each system

Area/ System	1	2	4	5	6	Total Time Per Transfer	Total Time Per Year
CIS	.067		.04	.018		.13	1.4
CRD				.018	.033	.051	.41
DMW				.018		.018	.14
FPS	.067	.05	.04	.018	.033	.21	1.7
LPS				.018		.018	.14
MSS				.018		.018	.14
PCS		.05	.04	.018	.033	.14	1.1
PIS	.067	.05		.018		.14	1.1
RCS		.05				.05	.4
RCW			.04	.018	.033	.10	.8
RPS				.018	.033	.051	.41
SWS			.04	.018		.058	.46
RVI					.033	.033	.26

Table 73-3.d System "At Risk" Times
Reactor Crane Load Group 4

8 Transfers per year
5 Areas affected per transfer
.·. .2 Hours in each area per transfer

Area 2 has 4 systems - .05 hours over each system
Area 5 has 11 systems - .018 hours over each system
Area 6 has 6 systems - .033 hours over each system
Area 7 has 2 systems - .1 hours over each system
Area 9 has 7 systems - .029 hours over each system

Area/ System	2	5	6	7	9	Total Time Per Transfer	Total Time Per Year
CIS		.018			.029	.047	.38
CRD		.018	.033	.1	.029	.18	1.4
DMW		.018			.029	.047	.38
FPS	.05	.018	.033			.1	.8
LPS		.018				.018	.14
MSS		.018				.018	.14
PCS	.05	.018	.033	.1		.2	1.6
PIS	.05	.018				.068	.54
RCS	.05					.05	.4
RCW		.018	.033		.029	.08	.64
RPS		.018	.033		.029	.08	.64
SFP					.029	.029	.23
SWS		.018			.029	.047	.38
RVI			.033			.033	.26

Table 73-3.e System "At Risk" Times
Reactor Crane Load Group 5

8 Transfers per year
3 Areas affected per transfer
∴ .33 Hours in each area per transfer

Area 5 has 11 systems - .03 hours over each system
Area 6 has 6 systems - .055 hours over each system
Area 8 has 5 systems - .066 hours over each system

Area/ System	5	6	8	Total Time Per Transfer	Total Time Per Year
CIS	.03		.066	.096	.77
CRD	.03	.055		.085	.68
DMW	.03			.03	.24
FPS	.03	.055		.085	.68
LPS	.03			.03	.24
MSS	.03			.03	.24
PCS	.03	.055	.066	.15	1.2
PIS	.03			.03	.24
RCW	.03	.055	.066	.15	1.2
RPS	.03	.055		.085	.68
SFP			.066	.066	.53
SWS	.03			.03	.24
RVI		.055		.055	.44

Table 73-3.f System "At Risk" Times
Emergency Condenser Beam Load Group

8 Transfers per year
2 Areas affected per transfer
∴ .5 Hour in each area per transfer

Area 5 has 11 systems - .045 hours over each system
Area 8 has 5 systems - .1 hours over each system

Area/ System	5	8	Total Time Per Transfer	Total Time Per Year
CIS	.045	.1	.15	1.2
CRD	.045		.045	.36
DMW	.045		.045	.36
FPS	.045		.045	.36
LPS	.045		.045	.36
MSS	.045		.045	.36
PCS	.045	.1	.15	1.2
PIS	.045		.045	.36
RCW	.045	.1	.15	1.2
RPS	.045		.045	.36
SFP		.1	.1	.8
SWS	.045	.1	.15	1.2

Table 73-3.g System "At Risk" Times
Cleanup Hoist Load Group

8 Transfers per year
1 Area affected per transfer
∴ 1 Hour in each area per transfer

Area 2 has 4 systems - .25 hours over each system

Area/ System	2	Total Time Per Transfer	Total Time Per Year
FPS	.25	.25	2.0
PCS	.25	.25	2.0
PIS	.25	.25	2.0
RCS	.25	.25	2.0

Table 73-3.h System "At Risk" Times
Turbine Crane Load Group

10, 30, 100 Transfers per year
6 Areas affected per transfer
∴ .17 Hours in each area per transfer

Area 13 has 8 systems - .021 hours over each system
Area 14 has 7 systems - .024 hours over each system
Area 15 has 5 systems - .034 hours over each system
Area 16 has 3 systems - .057 hours over each system
Area 17 has 3 systems - .057 hours over each system
Area 18 has 1 system - .17 hours over each system

Area/ System	13	14	15	16	17	18	Total Time Per Transfer	Total Time Per Year 10 Trans.	30 Trans.	100 Trans.
CDS		.024	.034				.058	.58	1.7	5.8
CIS	.021						.021	.21	.63	2.1
CRD	.021	.024	.034				.079	.79	2.4	7.9
CWS		.024					.024	.24	.72	2.4
DMW	.021		.034				.055	.55	1.7	5.5
FPS	.021		.034	.057	.057	.17	.34	3.4	10.	34.
FWS	.021						.021	.21	.63	2.1
MSS*	.021	.024					.045	.45	1.4	4.5
PCS*	.021						.021	.21	.63	2.1
RPS		.024					.024	.24	.72	2.4
SWS	.021		.034	.057			.11	1.1	3.3	11.
SPS				.057	.057		.11	1.1	3.3	11.
LOS					.057		.057	.57	1.7	5.7
T/G		.024					.024	.24	.72	2.4
MCS		.024					.024	.24	.72	2.4

*Failures of these systems are outside containment for this load group and cannot be combined with inside containment failures due to the nature of the systems - this applies to these systems only.

Table 73-4 Total System "at Risk" Times (Hours per year)

Load Group/ System	RC1	RC2	RC3	RC4	RC5	ECB	CUH	Turbine Crane 10 Xfer	Turbine Crane 30 Xfer	Turbine Crane 100 Xfer	Total "at Risk" Time TC-10	Total "at Risk" Time TC-30	Total "at Risk" Time TC-100
CDS								.58	1.7	5.8	.58	1.7	5.8
CIS	4.6	2.2	1.4	.38	.77	1.2		.21	.63	2.1	11.	11.	13.
CRD	7.2	2.2	.41	1.4	.68	.36		.79	2.4	7.9	13.	15.	20.
CWS								.24	.72	2.4	.24	.72	2.4
DMW	1.9	.76	.14	.38	.24	.36		.55	1.7	5.5	4.3	5.5	9.3
FPS	6.7	2.2	1.7	.8	.68	.36	2.0	3.4	10.	34.	18.	24.	48.
FWS								.21	.63	2.1	.21	.63	2.1
LPS	.72	.18	.14	.14	.24	.36					1.8		
MSS(I)	.72	.18	.14	.14	.24	.36					1.8		
MSS(O)								.45	1.4	4.5	.45	1.4	4.5
PCS(I)	8.2	2.9	1.1	1.6	1.2	1.2	2.0				18.		
PCS(O)								.21	.63	2.1	.21	.63	2.1
PIS	5.8	1.4	1.1	.54	.24	.36	2.0				11.		
RCS	2.1	.5	.4	.4			2.0				5.4		
RCW	3.2	1.8	.8	.64	1.2	1.2					8.8		
RPS	3.2	1.1	.41	.64	.68	.36		.24	.72	2.4	6.6	7.1	8.8
SFP	1.2	.97		.23	.53	.8					3.7		
SWS	1.9	1.5	.46	.38	.24	1.2		1.1	3.3	11.	6.8	9.0	17.
RVI	1.3	.32	.26	.26	.44						2.6		
SPS								1.1	3.3	11.	1.1	3.3	11.
LOS								.57	1.7	5.7	.57	1.7	5.7
T/G								.24	.72	2.4	.24	.72	2.4
MCS								.24	.72	2.4	.24	.72	2.4

Table 73-5 Frequency of System Damage Due to Heavy Load Drop (per year)

System	Damage Frequency TC-10	TC-30	TC-100
CDS - Condensate System	1.7E-8	5.1E-8	1.7E-7
CIS - Containment Isolation System	3.3E-7	NC	3.9E-7
CRD - Control Rod Drive System	3.9E-7	4.5E-7	6.0E-7
CWS - Circulating Water System	7.2E-9	2.2E-8	7.2E-8
DMW - Demineralized Water System	1.3E-7	1.7E-7	2.8E-7
FPS - Fire Protection System	5.4E-7	7.2E-7	1.4E-6
FWS - Feedwater System	6.3E-9	1.9E-8	6.3E-8
LPS - Liquid Poison System	5.4E-8	NC	NC
MSS(I) - Main Steam System (Inside Containment)	5.4E-8	NC	NC
MSS(O) - Main Steam System (Outside Containment)	1.4E-8	4.2E-8	1.4E-7
PCS(I) - Primary Coolant System (Inside Containment)	5.4E-7	NC	NC
PCS(O) - Primary Coolant System (Outside Containment)	6.3E-9	1.9E-8	6.3E-8
PIS - Post Incident System	3.3E-7	NC	NC
RCS - Reactor Cleanup System	1.6E-7	NC	NC
RCW - Reactor Cooling Water System	2.6E-7	NC	NC
RPS - Reactor Protection System	2.0E-7	2.1E-7	2.6E-7
SFP - Spent Fuel Pool	1.1E-7	NC	NC
SWS - Service Water System	2.0E-7	2.7E-7	5.1E-7
RVI -	7.8E-8	NC	NC
SPS -	3.3E-8	9.9E-8	3.3E-7
LOS -	1.7E-8	5.1E-8	1.7E-7
T/G - Turbine/Generator	7.2E-9	2.2E-8	7.2E-8
MCS -	7.2E-9	2.2E-8	7.2E-8
TOTAL	3.5E-6	4.1E-6	6.2E-6

taking the PCS inside containment, Table 73-4 shows the maximum potential "at risk" time to be 18 hours. Our calculations assumed this was totally avoidable and it would take an operator error to cause this "at risk" exposure and this exposure could be prevented by an interlock. However, we know that it is not possible to totally avoid the PCS during load transfers in containment. Therefore, let us assume that one-half this "at risk" time is unavoidable. This means that the frequency of load drop on the PCS would be

$$(9 \text{ hrs/yr} \times 3E\text{-}6/\text{hr}) + (9 \text{ hrs/yr} \times 3E\text{-}6/\text{hr} \times .01)$$
$$= 2.73E\text{-}5/\text{yr}$$

where the first parentheses contain the unavoidable "at risk" time (no operator error required) and the second parentheses contain the avoidable "at risk" time. The installation of interlocks can only eliminate the term in the second parentheses. Thus, with interlocks installed the frequency of load drop on the PCS would become

$$9 \text{ hrs/yr} \times 3E\text{-}6/\text{hr}$$
$$= 2.70E\text{-}5/\text{yr}$$

which is obviously a meaningless reduction. Although insufficient information was provided to prove it, we expect that a number of the systems have some unavoidable "at risk" time and that, as shown above, we would expect the frequency of load drop on these systems to be dominated by this unavoidable time, rendering the installation of interlocks useless.

4. Conclusions

An extremely conservative analysis of heavy load drop showed that even if all exposure of systems to load drop could be avoided, the installation of interlocks would result in an insignificant risk reduction. Further, we are able to conclude that the risk from heavy load drop is most likely dominated by unavoidable "at risk" exposures which would not be affected by the use of interlocks. A more detailed analysis, which could measure the actual risk reduction from the installation of interlocks could be performed. However, based on the results of this analysis we believe any additional effort to be unjustified. A more detailed analysis should result in the same conclusion, that the use of interlocks and stops to restrict crane travel would produce an insignificant reduction in risk.

Issue 74. Reactor Coolant System Vents

1. Introduction

This NRC-initiated issue concerns the venting of hydrogen from the primary coolant system (PCS) during a core damage accident. This hydrogen could interfere with the shutdown of the plant by blocking the PCS flow. The resolution of this issue includes the installation of vents in the PCS to vent the hydrogen to the containment. This vent has been installed, at Big Rock Point, but it is not operational. Completion of the vent project requires provisions for test connections, installation of seismic supports, and preparation of operating procedures.

2. Comments

Hydrogen is released during the oxidation of fuel cladding which can occur if the fuel is uncovered while high pressure is maintained in the PCS. These conditions can occur as a result of a small break LOCA or a loss of heat sink transient with a concurrent loss of the reactor depressurization system.

Hydrogen generation is a result of a core damage accident. The installation of primary system vents is an attempt to minimize the amount of damage done to the core during an accident sequence. (PRAs generally do not differentiate between a core damage accident and a core melt accident. Recovery from core damage is generally not modeled.)

This issue deals with situations where core damage has occurred. Core damage does not occur unless there are safety system failures. Therefore the primary system vents will provide a benefit only if some of the failed safety systems are recoverable. It will be assumed in this analysis that the appropriate systems are recoverable unless the accident sequence results in a condition, other than hydrogen generation, that would render the systems unrecoverable.

3. Analysis

This issue concerns the generation of hydrogen in the PCS. Hydrogen generated during a core damage accident could accumulate in the PCS and prevent circulation of the primary coolant. This flow blockage would result in an inability to restore heat sinks, the main condenser and the emergency condenser, that would be available if there were no hydrogen blocking coolant flow.

The scenario evaluated in this analysis is an initiator fails the main condenser and subsequently the emergency condenser fails and the reactor depressurization system (RDS) valves fail to open. This leads to a situation where coolant can be lost (through safety/relief valves) while the reactor is still at a high pressure.

The initiators that will result in an immediate loss of the main condenser system are presented in Table 74-1. Transients not listed require additional system failures to produce a loss of the main condenser. The frequencies of initiator times the system failure probabilities are smaller than the initiator frequencies presented in Table 74-1. Therefore, the initiators shown in this table should be the dominant contributors to potential hydrogen generation sequences.

The LOCA events presented in Table 74-1 will result in a failure of the emergency condenser as well as the main condenser. Portions of the makeup system to the emergency condenser are located inside the containment and must be manually operated or are not environmentally qualified. A LOCA inside containment will result in conditions under which the emergency condenser makeup systems may not function. Therefore the system is assumed to fail. Table 74-2 presents the expected failure probability for the emergency condenser (including makeup failure) for each initiator of Table 74-1. (All values are from the Big Rock Point PRA.)

The failure probability for the RDS valves failure to open is 8.6E-4. This is the common mode failure probability for failure of the 4 RDS valves to open. Only 3 RDS valves are required for system depressurization, however if any one valve should open it would vent the hydrogen generated as a result of core damage.

Table 74-1 Initiating Events That Result in the Loss of the Power Conversion System

I.E.	Frequency ($year^{-1}$)
Loss of Main Condenser	0.06
Loss of Offsite Power+	0.02
Loss of Instrument Air	0.06
Spurious Closure of MSIV	0.06
Spurious Closure of Both Recirculation Line Valves	0.017
Small Steam Line Break	1E-3
Small LOCA*	1E-3

*Only the small LOCA and steam line break are included because they are the only LOCAs where the high PCS pressure required for hydrogen generation is maintained.

+Includes a factor of .15 for failure to restore power in the short term.

Table 74-2 Emergency Condenser Failure Probabilities for Different Accident Initiators

Initiator	Emergency Condenser Failure Probability
Loss of Main Condenser	3.8E-3
Loss of Offsite Power	8.5E-2
Loss of Instrument Air	3.1E-1
Spurious Closure of MSIV	3.8E-3
Spurious Closure of Both Recirculation Line Valves	3.8E-3
Small Steam Line Break	1*
Small LOCA	1*

*Due to lack of environmental qualification.

The frequency of hydrogen generation from these initiating events can be calculated as

$$F_I P(EM|I) P(RDS)$$

where

F_I = initiator frequency

$P(EM|I)$ = emergency condenser failure probability given initiator I

$P(RDS)$ = RDS valve failure probability

If it is assumed that the hydrogen prevents recovery of the heat sinks this frequency is a core melt frequency. Installation of the primary system vents would allow for hydrogen venting and recovery of the heat sinks, the main condenser and emergency condenser for transient initiators or only the main condenser for LOCA initiators. If it is assumed that at least one of the heat sinks is recoverable the frequency of hydrogen generation is the reduction in core melt frequency that can be attained through installation of the primary system vents. This information is presented in Table 74-3. Also presented in this tale is the expected containment leakage probability for each type of initiator. Using this information and the relationship presented in Section II the populational exposure reduction is calculated and presented in Table 74-3.

4. Conclusion

Hydrogen generation occurs during a core damage accident. Through the use of primary system vents it is possible to rid the PCS of hydrogen that might otherwise prevent the use of systems that could minimize the core damage due to the accident. The analysis evaluated those situations where hydrogen generation could lead to the inability to recover heat sinks necessary to cool the core at high pressure. It was assumed that at least one heat sink was indeed recoverable once the hydrogen was vented. With these assumptions installation of a primary system vent can potentially reduce the populational exposure by approximately 5 man-rem/yr.

Table 74-3 Benefits Due to Primary System Vent Installation

Initiator	H_2 Generation Frequency (yr^{-1})	Containment Leakage Probability	Populational Exposure Reduction (man-rem/yr)
Loss of Main Condenser	2.0E-7	.23(1)	.05
Loss of Offsite Power	1.4E-6	.23	.4
Loss of Instrument Air	1.6E-5	.23	4.4
Spurious Closure of MSIV	2.0E-7	.20(2)	.05
Spurious Closure of Both Recirc. Line Valves	5.5E-8	.23	.02
Small Steam Line Creak	8.6E-7	.23	.2
Small LOCA	8.6E-7	.23	.2
Total			5.3

(1) A value of .23 is the sum of the probability of leakage through the vent valves (.13), leakage through the steam/feedwater lines (.066) and leakage due to failure of the MSIV to close (.03).

(2) Same as (1) except the MSIV is closed as part of the accident.

Issue 75B. Fire Protection RDS Radiant Energy Shield

1. Introduction

This issue concerns the possibility of a fire in one of the three following areas:

I Core spray pump room
II Emergency condenser
III The south face of the steam drum wall.

A fire in one of these areas has the potential for failing both the reactor depressurization system/core spray (RDS/CS) and the emergency condenser (EC). These two systems can be considered to be redundant safety systems. In addition, the NRC postulates that the fire could create a loss-of-offsite-power (LOSP) situation, which would make the main condenser (MC) unavailable as a heat sink. The resolution of this issue is to install thermal barriers between the appropriate equipment in the above three areas. The barriers would prevent the failure of both the EC and RDS/CS in the event of a fire in any of these three areas.

The following plant modifications are proposed:

I. Construction of a three-hour fire barrier between the core spray pumps and all alternate shutdown panel equipment and conduits.

II. Installation of radiant energy shields between the emergency condenser outlet valve conduits and the RDS conduits and valves on the south face of the steam drum enclosure and on the emergency condenser deck wherever the circuits are within 20 feet of each other.

III. Installation of a radiant energy shield between one emergency condenser inlet valve and the RDS valves on the emergency condenser deck.

2. Comments

The basis for this issue originates from 10CFR50, Appendix R, which requires that safe shutdown be achieved without the use of offsite power for 72 hours following the fire. This requirement assumes that the fire either destroys the offsite power source or that the fire causes a turbine trip which in turn disturbs the electrical grid enough to trip the offsite power breakers.

At Big Rock Point the following systems are available to cool down the reactor:

Heat Sinks	Sources of Water to Reactor Vessel
MC - Main Condenser	FW - Feedwater
EC - Emergency Condenser	CRD - Control Rod Drive Pumps
SDS - Shutdown Cooling System*	RDS/CS - Core Spray

In order for core damage to occur, the above systems must fail according to the following equation:

$$\text{Core damage} = (\text{RDS/CS}) \cdot [(\text{CRD}\cdot\text{FW}) + (\text{MC} \cdot \text{EC})]$$

As can be seen from the above equation, if a fire could fail both the RDS/CS and EC systems and simultaneously cause an LOSP (which would fail the MC), core damage would result.

3. Analysis

To determine the frequency of a core melt, it is necessary to determine the frequency of a fire in the three areas of concern, the probability that the fire will spread and cause a turbine trip and the probability of an induced LOSP.

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*No credit is taken for the SDS in this analysis, since it requires both low reactor vessel pressure and containment accessibility.

All three areas involved should have low probabilities for fire for the following reasons.

1. They are limited access areas,
2. They are low occupancy areas, and
3. There are no reasons for combustibles to be present in the areas.

Of the three areas, the core spray room appears to have the highest electrical loading. The frequency of a fire occurring is assumed to be the same as that assumed for the outside cable penetration are in the Big Rock Point PRA, 9.0E-4/yr. The outside cable penetration area has the same characteristics as listed above for these three areas.

At the present time, there are no sprinklers in any of the areas. There are no detectors in the area around the emergency condenser or on the steam drum wall. It is conservatively assumed that a fire in these areas would fail both the RDS/CS and EC systems (i.e., that there is no fire detection or suppression before damage occurs). Therefore the fire initiator frequency in these three areas is assumed to be 9.0E-4/yr.

Plant personnel do not believe that there is any reason for a fire in any of the three areas to cause the reactor turbine to trip. It is believed that a fire in the CS room involving the alternate shutdown panel (part of the emergency condenser system) would not cause a reactor trip. However, it will be estimated here that a turbine trip will occur for one fire in ten.

Big Rock Point has a small effect on the total electrical grid since it contributes less than one percent of the system's power. Although it is not anticipated that a turbine trip would trip the offsite power breakers, it will be conservatively estimated that this occurrence has a probability of 0.1.

The frequency of core damage due to fire, prior to any plant modifications is thus

$$\text{Core damage} = \begin{pmatrix}\text{frequency of} \\ \text{a fire}\end{pmatrix} \times \begin{pmatrix}\text{probability} \\ \text{of turbine trip}\end{pmatrix} \times \begin{pmatrix}\text{probability of} \\ \text{induced LOSP}\end{pmatrix}$$

$$= (9.0E\text{-}4) \times (.1) \times (.1)$$

$$= 9.0E\text{-}6/yr$$

The maximum benefit of the modification is achieved if the modification results in total fire independence of the two systems. If this assumption is made, an additional random failure must occur to achieve a core melt sequence.

The random failures of the two systems given a LOSP in the Big Rock Point PRA are:

P(RDS/CS) = 8.6E-3
P(EC) = 5.5E-2

The most conservative assumption is that the fire fails the system with the lowest random probability of failure (i.e., the fire fails the RDS/CS). Therefore, the frequency of core damage becomes

f(core damage) = frequency of fire x probability of turbine trip
x probability of induced LOSP
x probability of random failure of EC given LOSP

= frequency of core damage before changes
x probability of random failure of EC given LOSP

= 9.0E-6/yr x 5.5E-2
= 5.0E-7/yr.

4. Conclusions

The core melt frequencies are used to determine the benefit that can be realized by the proposed resolution of this issue. The man-rem exposure for both before and after cases are calculated for a Big Rock Point category 3, BRP-3, release. A containment failure probability of .23 is used. The fires in these areas should not directly result in containment failure. Therefore the containment failure probability would be the sum of:

the probabilities of failure of the vent valves to isolate (.13), leakage through the steam/feedwater lines (.066), and failure of the MSIV to close (.038). These are the dominant containment failure modes from the Big Rock Point PRA. The methodology used to calculate populational exposure is explained in more detail in Section II.

The populational exposure before the proposed modification is:

$$(9.0E\text{-}6/yr)(3 \text{ compartments})(0.23) \times (1.2E\text{+}6 \text{ man-rem/event}) = 7.4 \text{ man-rem/yr.}$$

The populational exposure after the proposed modification would be:

$$(5E\text{-}7/yr)(3)(0.23)(1.2E\text{+}6) = .4 \text{ man-rem/yr}$$

Thus the modification results in a potential benefit of 7 man-rem/yr.

Issue 75C. Fire Protection - Associated Circuits - Appendix R

1. Introduction

This issue concerns the frequency of fires occurring in control circuits for the two inlet valves of the emergency condenser. A fire occurring in the electrical equipment room or the penetration areas could cause a short-type failure, and fail both valves, disable the RDS/core spray, and create a loss of the power conversion system.

A resolution of this issue is to reroute the close coil wires for the two isolation condenser valves.

2. Comments

The fire frequencies used in this analysis are taken from the Big Rock Point PRA. An additional source of information was a paper presented to the International Meeting on Thermal Nuclear Reactor Safety (NUREG/CP-0027) August 29 through September 2, 1982 by Wesley A. Brinsfield of Wood-Leaver and Associates, Inc. and David P. Blanchard of Consumers Power Company.

In this analysis credit is given for manual detection and suppression of the fire. The probability of nondetection for the fire is considered .1 where manual detection is possible. This is the same value used in the Big Rock Point PRA. Where applicable, credit is taken for automatic sprinkler systems.

3. Analysis

For the three areas under consideration the frequencies of fires occurring are given in Table 75C-1.

Table 75C-1. Fire Frequencies for Vital Areas (per year)

Area	Frequency
Outside Penetration Area (OPA)	7.2E-3
Inside Penetration Area (IPA)	7.2E-3
Electrical Equipment Room (EER)	1.3E-2

The outside penetration area and the electrical equipment room have sprinkler systems. Those systems are assessed a failure probability of 3E-3 and 2E-3 respectively, (failure probabilities are from the Big Rock Point PRA).

As was done in the Big Rock Point PRA, the fire frequency is reduced by a factor of 75% to eliminate small, self-extinguishing fires. Utilizing these numbers to produce a core melt frequency produces the following results.

	Fire Frequency	Failure to Detect	Sprinkler Failure		Core Melt Frequency (/yr)
OPA	(7.2E-3)(.25)	.1	(3E-3)	=	5.4E-7
IPA	(7.2E-3)(.25)	.1	--	=	1.8E-4
EER	(1.3E-2)(.25)	.1	(2E-3)	=	6.5E-7
			TOTAL		1.8E-4

With the proposed modifications, the emergency condenser (EC) is no longer included in the common cause failures resulting from the fire. Therefore, the EC must fail independently for this core melt sequence to occur. The failure probability of the EC (given an LOSP where the containment is accessible and makeup is required) is 0.055 based on information in the Big Rock Point PRA.

After incorporating the proposed modification, the EC failure changes from 1.0 due to the fire to 0.055 due to faults not directly related to the fire. Therefore the new core melt frequency is:

$$(1.8E\text{-}4)(5.5E\text{-}2) = 1.0E\text{-}5/yr$$

4. Conclusions

The reduction in populational exposure is calculated using a containment failure probability of 1.0 for a Big Rock Point category 3 release. (The core melt frequency for these fire-initiated frequencies is dominated by a fire in the inside penetration area. Such a fire is expected to lead directly to containment failure. Thus a containment failure probability of 1.0 is used.)

Populational exposure before modification:

$$(1.8E\text{-}4/yr)(1.0)(1.2E{+}6 \text{ man-rem/event}) = 216 \text{ man-rem/yr}$$

Populational exposure after modification:

$$(1.0E\text{-}5/yr)(1.0)(1.2E{+}6 \text{ man-rem/event}) = 12 \text{ man-rem/yr}$$

Thus the benefit derived from the proposed modification is 204 man-rem/yr.

Issue 81. PORV Position Indication

1. Introduction

As a result of the accident at Three Mile Island, the NRC is requiring direct position indication of PORVs to help prevent a stuck open relief valve LOCA. For Big Rock Point this issue has been interpreted to include a requirement for position indication of the six spring-operated safety relief valves. At Big Rock Point, the relief valves are not power operated and are set to open and close at predetermined primary coolant system pressures.

2. Comments

The relief valves at Big Rock Point are pressure operated, not power operated, and release directly to the containment. If during a plant response to a transient initiator these valves open, or if these valves open as a transient initiator, primary coolant would be released to the containment. Under such conditions it is not reasonable to expect any operator recovery that would lead to a closure of the relief valve. (Any recovery action would have to occur at the valve since there are no remote manual or local manual controls.) Therefore the existence of relief valve position indicators would not increase the probability that the operator would recognize improperly open relief valves have opened and attempt to reclose them.

When a relief valve opens, it will release primary coolant directly to the containment. This differs from most PWRs where PORVs will vent to a relief tank and from BWRs with wet containments where the relief valves normally vent to a suppression pool. At Big Rock Point several monitors will indicate a release of primary coolant to the containment. These monitors include an airborne particulate radiation monitor, an airborne gaseous radioactivity monitor, and a containment atmosphere humidity monitor. The existence of position indicators on the relief valves would only pinpoint the source of the primary coolant leakage. The redundant capability it supplies to identify a loss of coolant would not significantly affect the probability that the operators would recognize the problem.

3. Analysis

No further analysis was necessary for this issue.

4. Conclusion

The addition of position indicators on the relief valves at the Big Rock Point Plant would have no noticeable effect on the populational exposure. The indicators do not provide any vital indication that is not available through at least three other monitoring systems. The position indication does not enable the operators to close the relief valve since the valves are inaccessible once they have opened.

References

1. W.A. Brinsfield and D. Blanchard, "The Risks Due to Fires at Big Rock Point," Proceedings of the International Meeting on Thermal Nuclear Reactor Safety, (NUREG/CP-0027) August 29 - September 2, 1982.

2. "Control of Heavy Loads at Nuclear Power Plants," NUREG-0612, U.S. Nuclear Regulatory Commission, July 1980.

3. "Control of Heavy Loads (C-10): Consumers Power Company Big Rock Point Nuclear Plant," Technical Evaluation Report TER-C5257-440 (Draft), Franklin Research Center, June 3, 1982.

4. D. G. Eisenhut, letter to: All Licensees of Operating BWRs and Applicants for BWR Operating Licenses, NRC Generic Letter 81-18, March 20, 1981.

5. K. N. Fleming and P. H. Raabe, "A Comparison of Three Methods for the Quantitative Analysis of Common Cause Failures," GA-A14568, General Atomic, May 1978.

6. "Probabilistic Risk Assessment: Big Rock Point Plant," Consumers Power Company, Docket 50-155.

7. "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH-1400 (NUREG-75/014), U.S. Nuclear Regulatory Commission, October 1975.

8. "Risk Based Categorization of Big Rock Point SEP Issues," SAI-83-130-WA (Rev. 1), Science Applications, Inc., June 30, 1983.

9. A. D. Swain and H. E. Guttmann, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, October 1980.

ATTACHMENT 3

FINDINGS FROM BIG ROCK POINT PRA

ATTACHMENT 3

Findings from Big Rock Point PRA

Based on our evaluation of the Big Rock Point risk study, we have obtained estimates of the values of various system upgradings.

We obtain our value estimates in the following way:

(1) We recalculate the frequencies of core-melt accidents taking into account the reductions of the frequencies due to system upgradings.

(2) We note that the offsite consequences of these sequences are dominated by cases where the containment fails to isolate; we multiply the frequencies of the core-melt accidents by its related conditional probabilities of containment isolation failure and obtain the sum of the products which corresponds to the frequency of core-melt and containment isolation failure accidents.

(3) For a core-melt sequence in which the containment fails to isolate, a release in category 3 will occur; this will produce 60 latent fatalities, on the average.

(4) We convert latent fatalities to person-rem by means of a conversion factor of 50 cancer fatalities per 10^6 person-rem.

(5) A value of $1000 for a reduction in exposure of 1 person-rem is used.

(6) It was assumed that the useful remaining life of Big Rock Point is 19 years.

In the table below, we list the values of various changes for two cases - the first is assuming that containment isolation has not been upgraded, and the second for the case where the reliability of containment isolation has been improved. For example, if containment isolation capability were upgraded, then there would be less of a benefit from improving SVs.

The various system upgradings are discussed in detail in our safety evaluation on Big Rock Point risk study.

What follows is a brief description of each issue:

(1) Emergency condenser makeup is one of the licensee's proposed modifications based on the findings of the risk study. This modification is to provide remote makeup to the emergency condenser via five water system by converting a manual makeup value into an automatic valve.

(2) Reactor depressurization system/core spray reliability is one of the licensee's proposed modifications. This modification is to provide high pressure makeup to the primary system by routing containment water due to a release from the primary system back to the primary system via feedwater/condensate systems. This avoids the need to depressurize the reactor using the reactor depressurization system.

(3) Post-incident system reliability is one of the licensee's proposed modifications. This modification calls for installing locks on the manual valves in the post-incident system so that the valves can only be locked in correct positions. This is to avoid human error of placing the valves in wrong positions after testing or maintenance.

(4) Early enclosure spray is also one of the licensee's proposed modifications. This modification is to eliminate a 15 minute time delay so that the enclosure spray can promptly activate when enclosure pressure reaches 2.2 psig due to a release from the primary system. This is to mitigate degradation of equipments due to excessive temperature.

(5) The shielding issue is related to NUREG-0737 Item II.B.2 requirement. The implementation of shielding is to reduce operator dose during repair and maintenance of long-term cooling systems in order to mitigate core-melt accidents.

(6) The control room habitability issue is related to NUREG-0737 Item III.D.3.4 requirement. The implementation is to ensure that control room operators will be adequately protected against toxic gases or a radioactive release and that the reactor can be safely operated or shut down.

(7) The issue of inadequate core cooling instrumentation is related to NUREG-0737 Item II.F.2 requirement. The requirement calls for installing a wide-range level instrumentation in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling.

(8) The hydrogen monitoring issue is related to NUREG-0737 Item II.B.3 requirement. The implementation of a hydrogen monitor is to inform operators of the hydrogen level in the containment due to a degraded core.

(9) The alternate shutdown system is one of the licensee's proposed modification to mitigate fire events. In the event of a fire, the control room instrumentation and control may not be available, and the alternate shutdown system can be used to safely shut down the reactor.

(10) The issue of secondary system instabilities is related to the licensee's proposed ATWS modification. With modification of reject valve control circuitry, the reactor will not trip in a load rejection event due to loss of feed pump suction. This modification is to reduce the frequency of demand for reactor trip.

(11) The automatic recirculation pump trip is a generic requirement for ATWS modification. In an ATWS event, the automatic recirculation pump trip will reduce reactor power promptly so that operators can have more time to take corrective measure, for example, injecting liquid poison.

	Containment Isolation Is Not Upgraded			Containment Isolation Is Upgraded[1]		
Issue	Estimated Value[2] For Reactor-Year	Person Rem Per Reactor-Year	Estimated Value For the rest of life	Estimated Value For Reactor-Year	Person Rem Per Reactor-Year	Estimated Value For the rest of life
Emergency Condenser Makeup	67K	67	1281K	20K	20	384K
Reactor Depressurization System Core Spray Reliability	6K	6	119K	2K	2	36K
Post-incident System Reliability	24K	24	465K	7K	7	140K
Early Enclosure Spray	91K	91	173K	27K	27	517K
Shielding	63K	63	1200K	19K	19	360K
Control Room Habitability	0.04K	0.04	1K	0.04K	0.04	1K
Inadequate Core Cooling Instrumentation	0.3K	0.3	5K	0.1K	0.1	2K
Hydrogen Monitoring	0.3K	0.3	5K	0.1K	0.1	2K
Alternate Shutdown System	228K	228	4332K	228K	228	4332K
Secondary System Instabilities	22K	22	410K	22K	22	410K
Recirculation Pump Trip	4K	4	68K	4K	4	68K

NOTE: (1) Assume that after upgrading of containment isolation capability the containment isolation failure probability would be 0.06.

(2) The estimated value is less than or on the order of the dollar value in the table.

APPENDIX E

REFERENCES TO CORRESPONDENCE
FOR EACH TOPIC EVALUATED

SEP Topic No.	Date	Reference
II-1.A	9/2/80	Letter from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Review of NRC Evaluation of SEP Topics II-1.A, II-1.B and II-1.C (Big Rock Point).
II-1.B	9/2/80	See reference for Topic II-1.A.
II-1.C	5/13/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: SEP Topic II-1.C, Potential Hazards Due to Nearby Industrial, Transportation and Military Facilities (Big Rock Point and Palisades).
II-2.A	8/3/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: Big Rock Point - SEP Topic II-2.A, Severe Weather Phenomena.
II-2.C	10/26/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic II-2.C, Atmospheric Transport and Diffusion Characteristics for Accident Analysis - Big Rock Point.
II-3.A	6/23/82	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: SEP Topics II-3.A, Hydrologic Description; II-3.B, Flooding Potential and Protection Requirements; II-3.B.1, Capability of Operating Plants To Cope With Design Basis Flood Conditions; II-3.C, Safety-Related Water Supply (Ultimate Heat Sink); and III-3.A, Effects of High Water Levels on Structures - Response to Safety Evaluation Reports.
	10/26/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Hydrology Topics II-3.A, II-3.B, II-3.B.1, II-3.C, and III-3.B - Big Rock Point.
II-3.B	10/26/82	See references for Topic II-3.A.
II-3.B.1	10/26/82	See references for Topic II-3.A.
II-3.C	10/26/82	See references for Topic II-3.A.
II-4	5/13/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: SEP Topics II-4, Geology and Seismology, and II-4.B, Proximity of Capable Tectonic Structures in Plant Vicinity - Response to NRC SER Dated October 12, 1982.
II-4.A	6/8/81	Letter from D. M. Crutchfield (NRC) to All SEP Owners, Subject: Site Specific Ground Response Spectra for SEP Plants Located in the Eastern United States.

SEP Topic No.	Date	Reference
II-4.B	10/12/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Review Topics II-4, Geology and Seismology, and II-4.B, Proximity of Capable Tectonic Structures in Plant Vicinity - Big Rock Point.
II-4.C	6/8/81	See reference for Topic II-4.A.
II-4.D	7/6/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic II-4.D, Stability of Slopes - Big Rock Point.
II-4.F	7/20/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic II-4.F, Settlement of Foundations and Buried Equipment - Big Rock Point Nuclear Generating Station.
III-1	9/19/83	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-1, Quality Group Classification of Components and Systems - Big Rock Point Nuclear Plant.
		See reference for Topic VII-3.
III-2	12/9/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-2, Wind and Tornado Loadings - Big Rock Point.
	7/5/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: SEP Topics III-2, Wind and Tornado Loadings and III-4.A, Tornado Missiles - PRA Evaluations.
III-3.A	12/2/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-3.A, Effects of High Water Level on Structures - Big Rock Point Nuclear Power Plant.
	6/23/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: SEP Topics II-3.A, Hydrologic Description; II-3.B, Flooding Potential and Protection Requirements; II-3.B.1, Capability of Operating Plants To Cope With Design Basis Flood Conditions; II-3.C, Safety-Related Water Supply (Ultimate Heat Sink); and III-3.A, Effects of High Water Levels on Structures - Response to Safety Evaluation Reports.
III-3.C	10/12/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-3.C, Inservice Inspection of Water Control Structures - Big Rock Point Plant.

SEP Topic No.	Date	Reference
	1/14/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic III-3.C, "Inservice Inspection of Water Control Structures" - Summary of Formalized Inspection Program.
III-4.A	11/29/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-4.A, Tornado Missiles - Big Rock Point Plant.
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III-4.B	11/29/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-4.B, Turbine Missiles - Big Rock Point.
III-4.C	10/14/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-4.C, Internally Generated Missiles - Big Rock Point.
III-4.D	8/12/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-4.D, Site Proximity Missiles (Including Aircraft) - Big Rock Point Nuclear Power Plant.
III-5.A	6/22/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic III-5.A, "High Energy Line Break Inside Containment" - Probabilistic Risk Assessment.
	9/22/83	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-5.A, Effects of Pipe Break on Structures, Systems and Components Inside Containment - Big Rock Point Nuclear Power Plant.
III-5.B	3/31/83	Letter from D. J. VandeWalle (NRC) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic III-5.B, Pipe Break Outside Containment - PRA Response to Final NRC SER.
III-6	10/19/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Safety Topics III-6, Seismic Design Considerations, and III-11, Component Integrity - Big Rock Point Nuclear Power Station.
	6/1/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topics III-6, "Seismic Design Considerations" and III-11, "Component Integrity."

SEP Topic No.	Date	Reference
III-7.B	9/30/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCO), Subject: SEP Topic III-7.B, Design Codes, Design Criteria and Load Combinations - Big Rock Point.
III-7.D	3/17/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Systematic Evaluation Program Topic III-7.D, Containment Structural Integrity Test - Big Rock Point.
III-8.A	3/2/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Systematic Evaluation Program Topic III-8.A, Loose Parts Monitoring and Core Barrel Vibration Program - Big Rock Point.
III-8.C	6/23/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point Plant - SEP Topic III-8.C, Irradiation Damage, Use of Sensitized Stainless Steel and Fatigue Resistance.
III-10.A	2/28/83	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic III-10.A, Thermal-Overload Protection for Motors of Motor-Operated Valves, Revised Final Safety Evaluation Report for Big Rock Point Nuclear Power Plant.
	6/1/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Integrated Assessment of Open Issues and Schedule for Issue Resolution (Including Environmental Equipment Qualification and Generic Letter 82-33 Issues).
IV-1.A	10/8/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: Topic IV-1.A, Operation With Less Than All Loops in Service at Big Rock Point.
IV-2	12/7/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: SEP Topic IV-2, Reactivity Control System - Big Rock Point Draft Safety Evaluation.
V-4	2/18/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic V-4, "Piping and Safe-End Integrity" - Response to NRC Final Evaluation.
V-5	6/13/83	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic V-5, Reactor Coolant Pressure Boundary Leakage Detection - Big Rock Point Nuclear Power Plant.

SEP Topic No.	Date	Reference
	6/26/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic V-5, "Reactor Coolant Pressure Boundary (RCPB) Leakage Detection" - Evaluation of Plant Leakage Detection Systems.
V-6	3/5/80	Letter from D. L. Ziemann (NRC) to D. P. Hoffman (CPCo), Subject: Completion of SEP Topic V-6, Reactor Vessel Integrity - Big Rock Point/Palisades Plant.
V-10.A	10/9/79	Letter from D. L. Ziemann (NRC) to D. Bixel (CPCo), Subject: SEP Topic V-10.A, Residual Heat Removal System Heat Exchanger Tube Failure.
V-10.B	9/10/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point SEP Topics V-10.B, RHR Reliability; V-11.B, RHR Interlock Requirements; and VII-3, Systems Required for Safe Shutdown (Safe Shutdown Systems Report).
V-11.A	12/15/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topics V-11.A, Requirements for Isolation of High and Low Pressure Systems and V-11.B, RHR Interlock Requirements - Revised Final Safety Evaluation Report for the Big Rock Point Nuclear Power Plant.
V-11.B	12/15/82	See reference for Topic V-11.A.
V-12.A	10/9/79	Letter from D. L. Ziemann (NRC) to D. Bixel (CPCo), Subject: Topic V-12.A, Water Purity of Boiling Water Reactor Primary Coolant.
VI-1	11/24/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VI-1, Organic Materials and Post-Accident Chemistry - Big Rock Point Nuclear Power Plant
VI-2.D	11/30/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle for the Big Rock Point Plant - Evaluation Report on Topics VI-2.D and VI-3.
VI-3	11/30/82	See reference for Topic VI-2.D.
VI-4	11/24/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: SEP Topic VI-4, Containment Isolation System (Electrical) - Big Rock Point.

SEP Topic No.	Date	Reference
	12/9/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VI-4, Containment Isolation System - Big Rock Point Nuclear Power Plant.
	6/22/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic VI-4, "Containment Isolation System" - PRA Evaluations.
VI-6	11/23/82	Letter from D. G. Eisenhut (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point - Containment Leak Testing.
VI-7.A.3	8/20/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VI-7.A.3, ECCS Actuation System, Final Safety Evaluation Report for Big Rock Point.
VI-7.A.4	4/10/79	Letter from D. L. Ziemann (NRC) to D. Bixel (CPCo), Subject: Amendment 26 to DPR-6.
VI-7.B	5/20/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point - SEP Topic VI-7.B, ESF Switchover From Injection to Recirculation Mode (Automatic ECCS Realignment).
VI-7.C	8/5/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: SEP Topics VI-7.C, ECCS Single Failure Criterion and Requirements for Locking Out Power to Valves, Including Independence of Interlocks on ECCS Valves; and VI-7.C.2, Failure Mode Analysis ECCS - Big Rock Point.
VI-7.C.1	2/22/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VI-7.C.1, Appendix K - Electrical Instrumentation and Control (EI&C) Re-Reviews, Safety Evaluation for Big Rock Point.
VI-7.C.2	8/5/81	See reference for Topic VI-7.C.
VI-7.D	8/17/78	Letter from D. G. Eisenhut (NRC) to C. Reed (CPCo),
VI-10.A	11/9/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VI-10.A, Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing, Final Safety Evaluation Report (Big Rock Point).

SEP Topic No.	Date	Reference
VII-1.A	3/11/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic VII-1.A, Isolation of Reactor Protection System From Non-Safety Systems, Including Qualification of Isolation Devices - Response to Final Safety Evaluation.
VII-1.B	8/17/78	See reference for Topic VI-7.D.
VII-2	5/18/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VII-2, Engineered Safety Feature System Control Logic and Design, Safety Evaluation Report for Big Rock Point.
VII-3	9/10/82	See reference for Topic V-10.B.
	12/17/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VII-3, Systems Required for Safe Shutdown, Revised Safety Evaluation Report for the Big Rock Point Nuclear Power Station.
VII-6	9/21/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: SEP Topic VII-6, Frequency Decay - Safety Evaluation for Big Rock Point.
VIII-1.A	7/8/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point - Adequacy of Station Electric Distribution System Voltages and Degraded Grid Protection for Class 1E Power Systems and SEP Topic VIII-1.A.
VIII-2	8/2/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic VIII-2, Onsite Emergency Power Systems - Diesel Generator, Revised Safety Evaluation for Big Rock Point.
VIII-3.A	4/22/81	Letter from D. P. Hoffman (CPCo) to D. M. Crutchfield (NRC), Subject: Docket No. 50-155 - License DPR-6, Big Rock Point - Systematic Evaluation Program Topic VIII-3.A, Station Battery Capacity Test Requirements.
VIII-3.B	3/10/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic VIII-3.B, DC Power System Bus Voltage Monitoring and Annunciation - Response to NRC Safety Evaluation Report.
VIII-4	4/25/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic VIII-4, Electrical Penetrations of Reactor Containment Topic Resolution by Probabilistic Risk Assessment.

SEP Topic No.	Date	Reference
IX-1	6/2/82	Letter from R. A. Vincent (CPCo) to D. M. Crutchfield (NRC), Subject: Docket No. 50-155 - License DPR-6, SEP Topic IX-1, Fuel Storage (Big Rock Point).
IX-3	9/28/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Evaluation of SEP Topic IX-3, Station Service and Cooling Water Systems for Big Rock Point.
IX-5	10/12/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic IX-5, Ventilation Systems - Big Rock Point.
IX-6	3/8/83	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point - Fire Protection Exception.
XIII-2	6/12/81	Letter from D. M. Crutchfield (NRC) to D .P. Hoffman (CPCo), Subject: Big Rock Point - List and Status of Systematic Evaluation Program, Phase II, Generic Topics
XV-1	6/25/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic XV-1, Decrease in Feedwater Temperature, Increase in Feedwater Flow and Increase in Steam Flow (Big Rock Point).
XV-3	6/18/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point - SEP Topic XV-3, Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Close of Main Steam Isolation Valve, and Steam Pressure Regulator Failure.
XV-4	10/16/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: Big Rock Point - SEP Topics XV-3 and XV-4.
XV-5	2/8/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic XV-5, Loss of Normal Feed-water Flow.
XV-7	3/11/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point - SEP Topic XV-7, Reactor Coolant Pump Seizure/Shaft Break.
XV-8	4/25/83	Letter from K. A. Toner (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - SEP Topic XV-8, Control Rod Misoperation - Control Rod Withdrawal Analysis.

SEP Topic No.	Date	Reference
XV-9	4/7/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: Big Rock Point - SEP Topic XV-9, Startup of an Inactive Loop at an Incorrect Temperature.
XV-11	12/2/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: Big Rock Point - SEP Topics XV-11, Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position and XV-13, Spectrum of Rod Drop Accidents.
XV-13	1/12/82	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: Big Rock Point SEP Topics XV-13, Spectrum of Rod Drop Accidents and XV-20, Radiological Consequences of Fuel Damaging Accidents.
XV-14	8/18/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: Big Rock Point - SEP Topics XV-14, XV-15, and XV-19.'
XV-15	8/18/81	See reference for Topic XV-14.
XV-16	12/28/81	Letter from D. M. Crutchfield (NRC) to D. P. Hoffman (CPCo), Subject: Big Rock Point - SEP Topic XV-16, Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment.
XV-18	12/16/83	Letter from D. J. VandeWalle (CPCo) to D. M. Crutchfield (NRC), Subject: Big Rock Point Plant - Technical Specification Change Request - Reactor Coolant Iodine Limit.
XV-19	10/20/82	Letter from D. M. Crutchfield (NRC) to D. J. VandeWalle (CPCo), Subject: SEP Topic XV-19, Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Break Within the Reactor Coolant Pressure Boundary (Radiological) - Big Rock Point.
XV-20	1/12/82	See reference for Topic XV-13.
XVII	8/17/78	See reference for Topic VI-7.D.

APPENDIX F

REVIEW OF OPERATING EXPERIENCE FOR THE BIG ROCK POINT NUCLEAR POWER PLANT

ORNL/NSIC-202

Contract No. W-7405-eng-26

Nuclear Safety Information Center

Engineering Technology Division

REVIEW OF THE OPERATING EXPERIENCE HISTORY OF BIG ROCK POINT THROUGH 1981 FOR THE NUCLEAR REGULATORY COMMISSION'S SYSTEMATIC EVALUATION PROGRAM

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EXECUTIVE SUMMARY

The Systematic Evaluation Program Branch of the Nuclear Regulatory Commission (NRC) is conducting the Systematic Evaluation Program (SEP) for the purpose of determining the safety margins of the design and operation of ten of the older operating commercial nuclear power plants in the United States. These ten plants are being reevaluated in terms of present NRC licensing requirements and regulations. Thus, the SEP is intended:

1. to establish documentation that shows how these ten plants compare with current acceptance criteria and guidelines on significant safety issues and to provide a technical rationale for acceptable departures from these criteria and guidelines,
2. to provide the capability for making integrated and balanced decisions with respect to any required backfitting, and
3. to provide for the early identification and resolution of any potential safety deficiency.

The SEP evaluates specific safety topics based on an integrated review of the overall ability of a plant to respond to certain design basis events including normal operation, transients, and postulated accidents.

As part of the SEP, the NRC contracted with the Oak Ridge National Laboratory to perform operating history reviews. These reviews are intended to augment the SEP's safety topic review and to aid in the determination of priorities for required backfitting during the integrated assessment. Each review includes collection and evaluation of availability and capacity factors, forced shutdowns, forced power reductions, reportable events, environmental events, and radiological release events.

This summary presents the results from the review of the operating experience of Big Rock Point which is a General Electric designed boiling-water reactor, owned and operated by Consumers Power Company. The plant is located four miles northeast of Charlevoix, Michigan, on the Little Traverse Bay of Lake Michigan. The station has a maximum allowable power level of 240 MW(t) [72 MW(e)]. Big Rock Point achieved initial criticality on September 27, 1962 and initial power operation began on December 8, 1962.

The cumulative reactor availability from 1962 through 1981 was 70.0% while the cumulative unit capacity factor was 68.6%. The availability fell below 70% only four times. The reactor was shut down on September 18, 1964, until September 4, 1965, to allow modifications to the thermal shield. This long outage resulted in a reactor availability of 14.8%, the lowest recorded throughout Big Rock Point's operating history. Reactor availability remained above 70% until ten years later, when in 1975, it dropped to 60.3%. Regulatory restrictions required a plant shutdown on January 16, 1975. Modifications to the post-incident cooling system were completed in June, at which time power operations resumed. Regulatory restrictions resulted in a reactor availability of 51.4% in 1976. The six month outage, beginning January 31, 1976, included refueling, and installation and startup of the reactor depressurization system. During the outage, several minor modifications were also made to the emergency core cooling system. The second lowest reactor availability was recorded in 1979 (24.0%). The plant was shut down from April 17 until November 4 to repair the inlet diffusers and repair a leak in a control rod drive (CRD) housing.

The operating history review focused on data evaluation which was divided into two segments: (1) evaluation of forced shutdowns and power reductions and (2) evaluation of reportable events. Design basis events (DBEs), which are defined in the NRC's *Standard Review Plan*,[1] are failures that initiate system transients and challenge engineered safety features. In the forced shutdown and power reduction segment, the review identified DBEs and recurring events that might indicate a potential operating concern. In the reportable event segment, which included environmental events and radiological release events, the review identified significant events and recurring events that might indicate a potential operating concern. Significant events were either DBEs or events with a loss of engineered safety function.

Forced Shutdowns and Power Reductions

From 1962 to 1981, Big Rock Point experienced 124 forced shutdowns and 69 forced power reductions. Twenty-one of the shutdowns and power reductions were identified as design basis events (DBEs). The events were of the following seven types:

1. loss of external load (9),
2. steam pressure regulator malfunction resulting in decreased steam flow (3),
3. turbine trip (3),
4. reactor coolant pump trip (2),
5. control rod maloperation (2),
6. loss of normal feedwater flow (1), and
7. loss of condenser vacuum (1).

Equipment failures caused ten of the DBEs while human errors accounted for seven. Electrical storms caused an additional four DBEs when the 138 kV transmission line was lost. All four storms occurred between 1966 and 1971. Sixteen of the DBEs occurred between 1962 and 1972. After 1972, the frequency of DBEs decreased significantly with equipment failures causing four DBEs and human errors causing one.

The DBE with the highest frequency was loss of an external load (9). Only three of these events resulted in a complete loss of offsite power with two occurring prior to the installation of the 46 kV transmission line in 1968. On September 17, 1965, a relaying malfunction resulted in a loss of power.[2] On August 8, 1966, the 138 kV breaker opened during a storm,[3] and on January 25, 1972, an offsite relaying scheme failed to clear a line fault.[4] This isolated the 138 kV and 46 kV lines from the plant. The other six losses of external loads were partial losses. In each event, the 138 kV transmission line was isolated from the plant. The causes of these six events were electrical storms (3), human errors (2), and relay malfunctions (1). The partial losses of offsite power occurred during two different time periods: June 1970 to September 1971 (4), and from April 1978 to May 1978 (2).

Reportable Events

In the reportable event segment of the operating review of Big Rock Point, 366 events were reviewed. Until 1974, Big Rock Point had reported an average of seven events per year. The peak year for reportable events occurred in 1977 when Big Rock Point filed reports on fifty events. Since 1974, the average number of reportable events has increased to thirty-nine. The primary cause of reportable events has been inherent equipment failure, which contributed to 52% of all events. Human error (including administrative, design, fabrication, installation, maintenance, and operator error) caused 46% of the reportable events. Other causes, such as lightning, were responsible for 1%. For the remaining 1% of reportable events, no causes were reported. No trends in the causes of reported events were identified.

Of the 366 reported events, six were identified as significant:

- loss of offsite power (2),
- containment integrity violated (1),
- both fire pumps unavailable while the automatic depressurization system (ADS) was unavailable (1),
- failure of two reactor protection system (RPS) channels while 138 kV line unavailable (1), and
- recirculation diffusers break off (1).

Inherent failures, human errors, and the weather each caused two events. No trend was observed in the frequency of significant events and no major problems in terms of plant safety were identified.

Recurring Events

The following three types of recurring events were noted during the review of Big Rock Point's operating history:

1. control rod drive problems,
2. failure fuel elements, and
3. failures involving the emergency condenser.

Many of the difficulties encountered with the control rod drives and fuel elements were limited to the earlier years of operation. Recurring problems involved: the control rods drifting out of the core, galling of the control rod index tubes, jamming of the rods so that they could be inserted but not withdrawn, and the withdrawal times less than the technical specifications limit. The first three types of problems have not occurred since 1968. The last time a control rod's withdrawal time was less than the limit was 1978.

Big Rock Point is a high power density reactor which has been involved in developmental programs to test high performance fuel elements. It was during these developmental programs that fuel cladding failures occurred. The fuel cladding failures did not pose any safety problems as power reductions kept the off-gas activity within acceptable limits.

Eleven events involved failures with the emergency condenser. Two of the failures rendered one of the two emergency condenser loops inoperable occurring in 1973 and 1978, respectively. However, a single tube bundle is sufficient to remove decay heat.

Conclusions

For this analysis of the operating history at Big Rock Point, 193 shutdowns and power reductions were reviewed along with 366 reportable events an other miscellaneous documentation concerning the operation of Big Rock Point. The objective was to identify those areas of plant operation that have compromised plant safety. This review identified no significant challenges to plant safety. In addition, the majority of problems identified to this review were not unique to Big Rock Point but are problems experienced by many older commercial nuclear power plants.

Overall, the operation of Big Rock Point has been quite satisfactory from a safety point of view. Fuel cladding failures and difficulties with control rod drive operations were limited to the early years of operation. Additionally, the fuel cladding failures were attributed to the developmental fuel program.

Two areas of marginal concern are the emergency condenser and the 138 kV transmission line. The emergency condenser was involved in eleven events and two of these resulted in the unavailability of one of the tube bundles. However, Big Rock Point's emergency condenser has two loops with one being capable of removing decay heat. The 138 kV transmission line has been lost nine times. Three events represented complete losses of offsite power, a typical number for a plant operating for 19 years.[5] The first two losses of offsite power occurred prior to the installation of the 46 kV transmission line.

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REVIEW OF THE OPERATING EXPERIENCE HISTORY OF BIG ROCK POINT THROUGH 1981 FOR THE NUCLEAR REGULATORY COMMISSION'S SYSTEMATIC EVALUATION PROGRAM

1. SCOPE OF REVIEW

The assessment of the operating experience review for Big Rock Point covered the time from initial criticality through 1981. The data collection and evaluation included the following aspects of operation: availability and capacity factors, forced shutdowns and power reductions, reportable events, events of environmental importance and radioactivity releases, and evaluation of the operating experience in total. Tables at the end of Chap. 1 show the codes assigned to operational aspects of forced shutdowns, power reductions, and reportable events. These codes are used in the reporting of data collected during the review of operating experience.

1.1 Availability and Capacity Factors

Both reactor and unit availability factors were compiled for all years. Starting with 1974, the unit capacity factors using the design electrical rating (DER) in net megawatts (electric) and the maximum dependable capacity (MDC) in net megawatts (electric) were compiled as well. Data for the capacity factors were not available from earlier years.

The two availability and two capacity factors are defined as follows:

1. reactor availability =

$$\frac{\text{hours reactor critical + reactor reserve shutdown hours}}{\text{period hours}}$$

2. unit availability =

$$\frac{\text{hours generator on line + unit reserve shutdown hours}}{\text{period hours}}$$

3. unit capacity (DER) = $$\frac{\text{net electrical energy generated}}{\text{period hours x DER net}} \times 100 ,$$

4. unit capacity (MDC) = $$\frac{\text{net electrical energy generated}}{\text{period hours x MDC net}} \times 100 .$$

Reserve shutdown hours are the amounts of time the reactor is not critical or the unit is shutdown for administrative or other similar reasons when operation could have been continued.

1.2 Review of Forced Shutdowns and Power Reductions

Forced shutdowns and power reductions were reviewed, and data were collected on each incident. Scheduled shutdowns for refueling and maintenance were not included in the review. However, if a utility had a refueling outage scheduled, the plant experienced a shutdown as a result of an abnormal event prior to the scheduled refueling, the utility reported that the refueling was being rescheduled to coincide with the current shutdown, and the utility reported the cause of the shutdown as refueling, then this shutdown was considered as forced. Only that portion of the outage time concerned with the abnormal event, not the refueling time, was included in the compilations.

The power reductions were included to provide information and details that may have been associated with a previous or subsequent shutdown. The power reductions are included in the proper chronological sequence with the shutdowns in the data tables for the forced shutdowns and power reductions (see Appendixes).

The following data were compiled annually for the forced shutdowns and power reductions:

1. date of occurrence,
2. duration (hours),
3. power level (percent),
4. notation of whether the shutdowns were also reportable events [e.g., a licensee event report (LER) or abnormal occurrence report (AOR)],
5. summary description of events associated with the forced shutdown or power reduction,
6. cause of shutdown (Table 1.1),
7. method of shutdown (Table 1.1),
8. system taken from NUREG-0161 (Ref. 1) that was directly involved with the shutdown or power reduction (Table 1.2),
9. component directly involved with the shutdown or power reduction (Table 1.3), and
10. categorization of the shutdown or power reduction.

Each shutdown or power reduction was placed in one of two sets of significance categories. The shutdowns and power reductions were first evaluated against criteria for design basis events (DBEs) as described in Chap. 15 of the *Standard Review Plan*.[2] If the shutdown or power reduction could not be categorized as a design-basis initiating event, then it was placed in one of a series of Nuclear Safety Information Center (NSIC) categories. For further discussions of the two sets of significance categories, use of the categories, and a listing of them, see Sect. 3.1.

The listings for the cause, shutdown method, system involved, and component involved along with their respective codes are those used in the NUREG-0020 series[3] ("Gray Books") on shutdowns. Note that the information listed under the "System involved" column in the data tables in the appendixes indicates (1) a general classification of systems (fully written out) and (2) a specific system, which is coded with two letters, within the general classification.

1.3 Review of Reportable Events

The operating events as reported in LERs and LER predecessors [e.g., abnormal occurrence reports (AOs*), unusual event reports, reportable occurrences (ROs)] were reviewed. These types of reportable events were retrieved from the NSIC computer file. Approximately six years ago, operating experience information for operating nuclear power plants was input to the NSIC file for the period of time before LERs were reviewed. Any documents that contained LER-type information (such as equipment failures or abnormal events) were coded or indexed so that they could be retrieved in the same manner as an LER. Primarily, this involved various types of operating reports and general correspondence for the late 1960s and early 1970s.

The following information was recorded for each reportable event reviewed:

1. LER number or other means of identification of report type,
2. NSIC accession number (a unique identification number assigned to each document entered into the NSIC computer file),
3. date of the event,
4. date of the report or letter transmitting the event description,
5. status of the plant at the time of the occurrence (Table 1.4),
6. system involved with the reportable event (Table 1.2),
7. type of equipment involved with the reportable event (Table 1.5),
8. type of instrument involved with the reportable event (Table 1.5),
9. status of the component (equipment) at the time of the occurrence (Table 1.4),
10. abnormal condition associated with the reportable event (e.g., corrosion, vibration, leak) (Table 1.6),
11. cause of the reportable event (Table 1.4), and
12. significance of the reportable event.

As a step in the evaluation process, each repo table event was screened using the criteria further discussed in Sect. 3.2.

Note that in the tables of reportable events in Appendix A for Big Rock Point, comments and/or details on the events were included.

1.4 Events of Environmental Importance and Releases of Radioactivity

Any significant or recurring environmental problems were summarized based on the review of forced shutdowns, power reductions, reportable events (environmental LERs), and operating reports. Routine radioactivity releases were tabulated as well, and releases where limits were exceeded were reviewed and are discussed in Sect. 4.5.1.4.

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*The AO designation used by some utilities for identifying operational events during a particular time frame is not to be confused with those safety-significant events listed in the Report to Congress on Abnormal Occurrences (NUREG-0090 series) which also uses the AO designation.

1.5 Evaluation of Operating Experience

The operating history of the plants was evaluated based on a review that involved screening, categorizing, and compiling data. Judgments and conclusions were made regarding safety problems, operations, trends (recurring problems), or potential safety concerns. Events were analyzed to determine their safety significance from the information provided through the various operating reports and the review process. The final safety analysis reports provided specific plant and equipment details when necessary.

Table 1.1. Codes for causes of forced shutdown or power reduction and methods of shutdown

	Causes
A	Equipment failure
B	Maintenance or testing
C	Refueling
D	Regulatory restriction
E	Operator training and license exams
F	Administrative
G	Operational error
H	Other
	Methods
1	Manual
2	Manual scram
3	Automatic scram
4	Continuation
5	Load reduction
9	Other

Table 1.2. Codes for systems involved with the forced shutdown, power reduction, or reportable event

System	Code
Reactor	RX
Reactor vessel internals	RA
Reactivity control systems	RB
Reactor core	RC
Reactor coolant and connected systems	CX
Reactor vessels and appurtenances	CA
Coolant recirculation systems and controls	CB
Main steam systems and controls	CC
Main steam isolation systems and controls	CD
Reactor core isolation cooling systems and controls	CE
Residual heat removal systems and controls	CF
Reactor coolant cleanup systems and controls	CG
Feedwater systems and controls	CH
Reactor coolant pressure boundary leakage detection systems	CI
Other coolant subsystems and their controls	CJ
Engineered safety features	SX
Reactor containment systems	SA
Containment heat removal systems and controls	SB
Containment air purification and cleanup systems and controls	SC
Containment isolation systems and controls	SD
Containment combustible control systems and controls	SE
Emergency core cooling systems and controls	SF
Core reflooding system	SF-A
Low-pressure safety injection system and controls	SF-B
High-pressure safety injection system and controls	SF-C
Core spray system and controls	SF-D
Control room habitability systems and controls	SG
Other engineered safety feature systems and their controls	SH
Containment purge system and controls	SH-A
Containment spray system and controls	SH-B
Auxiliary feedwater system and controls	SH-C
Standby gas treatment systems and controls	SH-D
Instrumentation and controls	IX
Reactor trip systems	IA
Engineered safety feature instrument systems	IB
Systems required for safe shutdown	IC
Safety-related display instrumentation	ID
Other instrument systems required for safety	IE
Other instrument systems not required for safety	IF

Table 1.2 (continued)

System	Code
Electric power systems	EX
Offsite power systems and controls	EA
AC onsite power systems and controls	EB
DC onsite power systems and controls	EC
Onsite power systems and controls (composite ac and dc)	ED
Emergency generator systems and controls	EE
Emergency lighting systems and controls	EF
Other electric power systems and controls	EG
Fuel storage and handling systems	FX
New fuel storage facilities	FA
Spent-fuel storage facilities	FB
Spent-fuel pool cooling and cleanup systems and controls	FC
Fuel handling systems	FD
Auxiliary water systems	WX
Station service water systems and controls	WA
Cooling systems for reactor auxiliaries and controls	WB
Demineralized water makeup systems and controls	WC
Potable and sanitary water systems and controls	WD
Ultimate heat sink facilities	WE
Condensate storage facilities	WF
Other auxiliary water systems and controls	WG
Auxiliary process systems	PX
Compressed air systems and controls	PA
Process sampling systems	PB
Chemical, volume control, and liquid poison systems and controls	PC
Failed-fuel detection systems	PD
Other auxiliary process systems and controls	PE
Other auxiliary systems	AX
Air conditioning, heating, cooling, and ventilation systems and controls	AA
Fire protection systems and controls	AB
Communication systems	AC
Other auxiliary systems and controls	AD
Steam and power conversion systems	HX
Turbine-generators and controls	HA
Main steam supply systems and controls (other than CC)	HB
Main condenser systems and controls	HC
Turbine gland sealing systems and controls	HD
Turbine bypass systems and controls	HE

Table 1.2 (continued)

System	Code
Circulating water systems and controls	HF
Condensate cleanup systems and controls	HG
Condensate and feedwater systems and controls (other than CH)	HH
Steam generator blowdown systems and controls	HI
Other features of steam and power conversion systems (not included elsewhere)	HJ
Radioactive waste management systems	MX
Liquid radioactive waste management systems	MA
Gaseous radioactive waste management systems	MB
Process and effluent radiological monitoring systems	MC
Solid radioactive waste management systems	MD
Radiation protection systems	BX
Area monitoring systems	BA
Airborne radioactivity monitoring systems	BB
Other	XX
Not applicable	ZZ

Table 1.3. Components involved with the forced shutdown or power reduction

Component type	Including
Accumulators	Scram accumulators Safety injection tanks Surge tanks
Air dryers	
Annunciator modules	Alarms Bells Buzzers Claxons Horns Gongs Sirens
Batteries and chargers	Chargers Dry cells Wet cells Storage cells
Blowers	Compressors Gas circulators Fans Ventilators
Circuit closers/interruptors	Circuit breakers Contactors Controllers Starters Switches (other than sensors) Switchgear
Control rods	Poison curtains
Control rod drive mechanisms	
Demineralizers	Ion exchangers
Electrical conductors	Bus Cable Wire
Engines, internal combustion	Butane engines Diesel engines Gasoline engines Natural gas engines Propane engines
Filters	Strainers Screens
Fuel elements	
Generators	Inverters
Heaters, electric	

Table 1.3 (continued)

Component type	Including
Heat exchangers	Condensers Coolers Evaporators Regenerative heat exchangers Steam generators Fan coil units
Instrumentation and controls	
Mechanical function units	Mechanical controllers Governors Gear boxes Varidrives Couplings
Motors	Electric motors Hydraulic motors Pneumatic (air) motors Servo motors
Penetrations, primary containment air locks	
Pipes, fittings	
Pumps	
Recombiners	
Relays	
Shock suppressors and supports	
Transformers	
Turbines	Steam turbines Gas turbines Hydro turbines
Valves	Valves Dampers
Valve operators	
Vessels, pressure	Containment vessels Dry wells Pressure suppression Pressurizers Reactor vessels

Table 1.4. Codes for data collected on plant status, component status, and cause of reportable events

Code	Plant status	Component status	Cause of reportable event
A	Construction	Maintenance and repair	Administrative error
B	Operation	Operation	Design error
C	Refueling	Testing	Fabrication error
D	Shutdown		Inherent error
E			Installation error
F			Lightning
G			Maintenance error
H			Operation error
I			Weather

Table 1.5. Codes for equipment and instruments involved in reportable events

Code		Code	
	Equipment		
A	Accumulator	W	Internal combustion engine
B	Air drier	X	Motor
C	Battery and charger	Y	Nozzle
D	Bearing	Z	Pipe and pipe fitting
E	Blower and dampers	AA	Power supply
F	Breaker	BB	Pressure vessel
G	Cables and connectors	CC	Pressurizer
H	Condenser	DD	Pump
I	Control rod	EE	Recombiner
J	Control rod drive	FF	Seal
K	Cooling tower	GG	Shock absorber
L	Crane	HH	Solenoid
M	Demineralizer	II	Steam generator
N	Diesel generator	JJ	Storage container
O	Fastener	KK	Support structure
P	Filter/screen	LL	Transformer
Q	Flange	MM	Tubing
R	Fuel element	NN	Turbine
S	Fuse	OO	Valve
T	Generator	PP	Valve, check
U	Heat exchanger	QQ	Valve operator
V	Heater		
	Instrumentation		
A	Alarm	L	Power range instrument
B	Amplifier	M	Pressure sensor
C	Electronic function unit	N	Radiation monitor
D	Failed fuel detection instrument	O	Recorder
E	Flow sensor	P	Relay
F	In-core instrument	Q	Seismic instrument
G	Indicator	R	Solid state device
H	Intermediate range instrument	S	Start-up range instrument
I	Level sensor	T	Switch
J	Meteorological instrument	U	Temperature sensor
K	Position instrument		

Table 1.6. Codes used for reportable events—abnormal conditions

Mechanical

AA	Normal wear/aging/end of life: expected effect of normal usage
AB	Excessive wear/clearance: component (especially a moving component) experiences excessive wear or too much clearance or gap exists because of overuse, lack of lubrication
AC	Deterioration/damage: component is no longer at an acceptable level of quality (e.g., high temperature causes rubber seals to chemically break down or deteriorate, insulation breaks down)
AD	Break/shear: structural component physically breaks apart (not when something "breaks down")
AE	Warp/bend/deformation: shape of component is physically distorted
AF	Collapse: tank or compartment has an external pressure exerted that results in deformation
AG	Seize/bind/jam: component has inhibited movement caused by crud, foreign material, mechanical bonding, another component
AH	Excessive mechanical loads: mechanical load exceeds design limits
AI	Mechanical fatigue: failure due to repeated stress
AJ	Impact: the result of the force of one object striking another
AK	Improper lubrication: insufficient or incorrect lubrication
AL	Missing/loose: component is missing from its proper place or is loose or has undesired free movement
AM	Wrong part: incorrect component installed in a piece of equipment
AN	Wrong material: incorrect material used during fabrication or installation
AO	Weld-related failure: failure caused by defective weld or located in the heat-affected zone
AP	Vibration other than flow induced: vibration from any cause other than fluid flow
AQ	Crud buildup: buildup of foreign material such as dust, sticks, trash (not corrosion or boron precipitation)
AR	Corrosion/oxidation: unanticipated attack
AS	Dropped: component is dropped (includes control rod that is "dropped" into core)
AT	Leak, internal, within system: leak from one part of a system to another part of the same system
AU	Leak, internal, between systems: leak from one system to a different system
AV	Crack: defect in a component does not result in a leak through the wall

Table 1.6 (continued)

AW	Leak, external: defect in a component results in a leak from the system that is contained in an onsite building
AX	Leak to environment: leak not resulting from a cracked or broken component
AY	Was opened/transfers open: component is/was opened by error or spuriously opens
AZ	Was closed/transferred closed: component is/was wrongly closed by error or spuriously closes
BA	Fails to open: component is in the closed state <u>and</u> fails to open on demand (e.g., the circuit breaker "fails to open" when an overcurrent occurs)
BB	Fails to close: component is in the open state <u>and</u> fails to close on demand
BC	Malposition or maladjustment: component is out of desired position (e.g., normally open valve is closed) or adjusted improperly (not for instrument drift or out of calibration)
BD	Failure to start/turn on: component fails to start on demand
BE	Stopped/failed to continue to run: component fails to continue running when it has previously started
BF	Tripped: component <u>automatically</u> trips on or off (desired or undesired) (e.g., the turbine tripped because of overspeed, the circuit breaker tripped because of overspeed, or the circuit breaker tripped because of overload)
BG	Deenergized/power removed: component on system loses its driving potential but not necessarily electrical power [e.g., (1) a fuse blows and there is no power to a sensor, and the sensor is deenergized; (2) a valve closes off the steam supply to a turbine, and the turbine has no driving power]
BH	Energized/power applied: component or system gains its driving potential but not necessarily electrical power (e.g., valve is opened allowing steam to turn a turbine)
BI	Unacceptable response time: component does not respond to a demand within a desired time frame but does not otherwise fail (e.g., a diesel generator fails to come to full speed within the time constraint)
BJ	High pressure: higher than normal or desired pressure exists in a component or system (<u>does</u> <u>not</u> include instrument misindications)
BK	Low pressure: lower than normal or desired pressure exists in a component or system (<u>does</u> <u>not</u> include instrument misindication)
BL	High temperature: component experiences a higher than normal or desired temperature

Table 1.6 (continued)

BM Low temperature: component (or system) experiences a lower than normal or desired temperature

BN Freezing: fluid medium (e.g., water) freezes in or on a component

BO Excessive thermal cycling: frequent changes in temperature that could result in metal fatigue or cracking

BP Unacceptable heatup/cooldown rate: heatup or cooldown rate exceeds limits

BQ Thermal transient: system experiences an undesired or unstable thermal transient or thermal change

BR Excessive number of pressure cycles: system experiences an undesired number of significant pressure changes (e.g., pressure pulses as from a positive displacement pump)

BS High level/volume: higher than normal or desired level or volume exists (actual or potential) in a component, such as tank or sump, or area, such as auxiliary building (not for instrument misindication)

BT Low level/volume: lower than normal or desired level or volume exists in a component (not for instrument misindication)

BU Abnormal concentration/pH: an abnormal (either high or low) concentration of a chemical or reagent exists in a fluid system or an abnormal pH exists (does not include abnormal boron concentrations)

BV Abnormal boron concentration: process system control rod has an abnormal boron concentration from burnup, dilution, or overaddition

BW Overspeed: speed in excess of design limits

BX Cladding failure: cladding of a component fails (e.g., the cladding of a fuel pellet is breached, and radioactive fuel leaks out)

BY Burning/smoking: component is on fire or smoking

BZ Engaged: component engages or meshes (this is not to be used when a component binds or becomes stuck or jammed)

CA Disengaged/uncoupled: component disengages, loses required friction, or is no longer meshed (as in gears); for example, the clutch on the motor disengages from the shaft (this should not be used for dropped control rods)

<u>Electric/instruments</u>

EA Excessive electrical loads: electrical loads exceed design rating

EB Overvoltage/undercurrent: component failure produces an overvoltage/undercurrent condition other than open circuits

EC Undervoltage/overcurrent: component failure produces an undervoltage/overcurrent condition other than shorts

Table 1.6 (continued)

ED Short circuit/arcing/low impedance: electrical component shorts or arcs in the circuit or has a low impedance including shorts to ground

EE Open circuit/high impedance/bad electrical contact: electrical component has a structural break, or electrical contacts fail to contact and fail to pass the desired current

EF Erratic operation: component (especially electrical or instrument) behaves erratically or inconsistently (if an instrument produces a bad but constant signal, use "EG"; if an instrument produces an inconsistent signal use "EF")

EG Erroneous/no signal: electrical component or instrument produces an erroneous signal or gives no signal at all (not for out-of-calibration error)

EH Drift: a change in a setting caused by aging or change of physical characteristics (does not include personnel errors or a physical shift of a component)

EI Out of calibration: component (particularly instruments) become out of adjustment or calibration (does not include drift)

EJ Electromagnetic interference: abnormal indication or action resulting from unanticipated electromagnetic field

EK Instrument snubbing: dampening of pulsating signals to an instrument

<u>Hydraulic</u>

HA High flow: higher than normal or desired flow exists in a component/system (does not include instrument misindication (see code EG)

HB Low flow: lower than normal or desired flow exists in a component/system (does not include instrument misindication)

HC No flow or impulse: fluid flowing through a pipe, filter, orifice, or trench or the fluid in an impulse line (e.g., instrument sensing line) is blocked completely or decreased due to some foreign material, crud, closed (either partially or completely) valve or damper, or insufficient flow area

HD Flow induced vibration

HE Cavitation

HF Erosion

HG Vortex formation

HH Water hammer

HI Pressure pulse/surge

Table 1.6 (continued)

HJ	Air/steam binding
HK	Loss of pump section
HL	Boron precipitation
	<u>Other</u>
OA	Declared inoperable: component or system is declared inoperable as required by Technical Specifications but may be capable of partially or completely performing its desired duties when requested (a component/system that is <u>completely</u> failed should not use this code)
OB	Flux anomaly: flux characteristics of the reactor core are not as required or desired (e.g., flux spike due to xenon burnout)
OC	Test not performed: operator or test personnel fails to perform a required test within the required period
OD	Radioactivity contamination: component, system, or area becomes more radioactive than desired or expected
OE	Temporary modification: an installation intended for short term use (usually this is for maintenance or modification of installed equipment)
OF	Environmental anomaly
OG	Airborne release
OH	Waterborne release
OI	Operator communication
OJ	Operator incorrect action
OK	Procedure or record error

2. SOURCES OF INFORMATION

Several sources of information including periodic (annual, quarterly, and monthly) NRC publications were used in the review. Some sources contained information relative to more than one area within the scope of the review.

2.1 Availability and Capacity Factors

The availability and capacity factors were either extracted or calculated from data given in the Gray Books[3] from 1974 through 1981 (the first Gray Book was issued in May 1974). Prior to 1974, annual or semiannual reports were used to compile availability factors only.

2.2 Forced Reactor Shutdowns and Power Reductions

Review of the forced power reductions involved checking the following sources for accuracy and completeness of details.

1. Nuclear Power Plant Operating Experience for 19XX, for the years 1973-1981 (Refs. 4-11). The report for 1981 has not been published. However, because work on the section on outages in these reports has been performed by NSIC since 1973, the draft copy of this report for 1981 was available.
2. NUREG-0020 series[3] (Gray Books).
3. Annual or semiannual reports of the Big Rock Point plant from the time of startup through 1977. For 1977 through 1981, monthly operating reports were used because the utilities were no longer required to file annual reports. The review of power reductions involved primarily the annual, semiannual, and monthly reports.

2.3 Reportable Events

The NSIC computer file of LERs was the primary source of information in reviewing reportable events. Material on the NSIC computer file consists of the appropriate bibliographic material, title, 100-word abstract, and keywords. When additional information on the event was needed, the original LER (or equivalent) was consulted by examining (1) those full-sized copies on file at NSIC (for the years 1976-1981); (2) the microfiche file of docket material at NSIC; or (3) the appropriate operating report (semiannual, annual, or monthly).

Two computer files on RECON (a computer retrieval system containing ~40 data bases operated at ORNL) were used extensively. Printouts were obtained from the files for Big Rock Point to provide coverage on many types of "docket material," including reportable events, where the licensee may have been in correspondence with NRC [or the Atomic Energy Commission (AEC)] concerning a particular event. Licensees are often requested to submit additional information or perform further analysis.

Before the LERs came into existence in the mid-1970s, it was not unusual for licensees to submit, on their own or at the request of NRC or AEC, more than one letter transmitting information on a particular event. Thus, these printouts provided additional sources of information on reportable events.

Several special publications were reviewed to provide details on events of significance. After further analyses and examination of the following publications, details, evaluations, or assessments could be found other than those provided in the appropriate NRC-requested transmission.

1. "Reports to Congress on Abnormal Occurrences," NUREG-0090 series[12],
2. "Power Reactor Event Series" (formerly Current Event Series) published bimonthly by NRC,
3. "Operating Experiences," a section of each issue of the *Nuclear Safety* journal, and
4. the publications of NRC's Office of Inspection and Enforcement (IE), such as operating experience bulletins, IE bulletions, IE circulars, and IE information notices.

2.4 Environmental Events and Releases of Radioactivity

Events of environmental importance were obtained as a result of conducting the overall review of the plant's operating history, and the sources of information involve all types of documents listed thus far.

The data for radioactivity releases were compiled primarily from *Radioactive Materials Released from Nuclear Power Plants — Annual Report 1977* (Ref. 13). This report presents year-by-year comparisons for plants in a number of different categories (such as solid, gas, liquid, noble gas, and tritium). Data for 1978 were taken from *Radioactive Materials Released from Nuclear Power Plants — Annual Report 1978* (Ref. 14). Data for 1979, 1980, and 1981 were compiled from the annual environmental reports submitted by Big Rock Point.

3. TECHNICAL APPROACH FOR EVALUATIONS OF OPERATING HISTORY

Forced shutdowns (and power reductions) and reportable events were the two areas focused on in the evaluation of the operating history of Big Rock Point. Given the large number of both forced shutdowns and reportable events, it was necessary to develop consistent review procedures that involved screening and categorizing of both occurrences. After the events were screened and categorized, the study then assessed the safety significance of the events and analyzed the categories of events for various trends and recurring problems.

The approach in evaluation of operational events (forced shutdowns and reportable occurrences) consisted primarily of a three-step process: (1) compilation of information on the events, (2) screening of the events for significance using selected criteria and guidelines, and (3) evaluation of the significance and importance of the events from a safety standpoint. The evaluations were to determine those areas where safety problems existed in terms of systems, equipment, procedures, and human error.

Shutdowns were evaluated against the DBEs found in Chap. 15 of the *Standard Review Plan.*[2] The DBEs are those postulated disturbances in process variables or postulated malfunctions or failures of equipment that the plants are designed to withstand and that licensees analyze and include in safety analysis reports (SARs). The SAR provides the opportunity for the effects of anticipated process disturbances and postulated component failures to be examined to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations (or to identify the limitations of expected performance).

The intent is to organize the transients and accidents considered by the licensee and presented in the SAR in a manner that will:

1. ensure that a sufficiently broad spectrum of initiating events has been considered,
2. categorize the initiating events by type and expected frequency of occurrence so that only the limiting cases in each group need to be quantitatively analyzed, and
3. permit the consistent application of specific acceptance criteria for each postulated initiating event.

Each postulated initiating event is to be assigned to one of the following categories:

1. increase in heat removal by the turbine plant,
2. decrease in heat removal by the turbine plant,
3. decrease in reactor coolant system flow rate,
4. anomalies in reactivity and power distribution,
5. increase in reactor coolant inventory,
6. decrease in reactor coolant inventory,
7. radioactive release from a subsystem or component, or
8. anticipated transients without scram.

Those shutdowns identified as design-basis initiating events were categorized as such. If the shutdown was not a DBE, then it was assigned a category from a list developed by NSIC to indicate the nature and type of error or failure. The NSIC categories for shutdowns not caused by DBEs were examined as part of a trends analysis.

Reportable events were screened using the criteria presented in Sect. 3.2 and were categorized according to their significance. The information collected on the reportable events was used to analyze trends for all reportable events, both significant and not significant.

3.1 Significant Shutdowns and Power Reductions

For the purposes of compiling information and evaluation, power reductions were treated in the same manner as forced shutdowns.

3.1.1 Criteria for significant shutdowns and power reductions

As indicated previously, the occurrences identified as DBEs were used as criteria to categorize and note significant shutdowns. These events are listed in Table 3.1 at the end of Sect. 3 as they are found in Chap. 15 of the *Standard Review Plan.*[1]

3.1.2 Use of criteria for determining significant shutdowns and power reductions

Generic design-basis initiating events such as "increase in heat removal by the secondary system" or "decrease in reactor coolant system flow rate," were used as primary flags for reviewing the forced shutdowns (and power reductions). Once the generic type of event was identified, the particular initiating event was determined from the details associated with the shutdown. For example, if the reactor shuts down because of an increase in heat removal because a feedwater regulator valve failed open, the shutdown is a generic type 1 DBE. Specifically, based on the initiating event (valve failed open), it is a 1.2 DBE — "feedwater system malfunction that results in an increase in feedwater flow." Some shutdowns were readily identifiable as specific DBEs, such as tripping of a main coolant pump, a 3.1 DBE. Once categorized as a DBE, the shutdown was considered significant regardless of the resulting effect on the plant (because a DBE had been initiated).

Loss of flow from one feedwater loop was considered sufficient to qualify as a 2.7 DBE — "loss of normal feedwater flow." The closure of a main steam isolation valve in one loop was considered sufficient to qualify as a 2.4 DBE — "inadvertent closure of main steam isolation valves."

3.1.3 Non-DBE shutdown and power reduction categorization

Those shutdowns that were not DBEs were assigned NSIC categories (Table 3.2) to provide more information on the failure or error associated with the shutdown. With these categories, more specific types of errors and failures could be examined through tabular summaries to focus the reviewer's attention on problem areas (safety related or not) that were not revealed by the DBE categories.

The causes (Table 1.1) for non-DBE shutdowns taken from the Gray Books are limited and very general, while NSIC cause categories are more specific. Thus, as an example, the number of Gray Book causes noted as equipment failure should not be expected to equal those identified as equipment failures with the NSIC categories. Other NSIC categories, such as component failure, could be classified as an equipment failure if the only available designations for cause were those listed in the Gray Books.

3.2 Significant Reportable Events

3.2.1 Criteria for significant reportable events

Two groups of criteria were used in determining significant reportable events. The first set of criteria (Table 3.3) indicates those events that are definitely significant in terms of safety; they are termed significant. The second set of criteria (Table 3.4) indicates events that may be of potential concern. These events which might require additional information or evaluation to determine their full implication, were noted as conditionally significant.

3.2.2 Use of criteria for determining significant reportable events

The reportable events were all reviewed, applying the two sets of criteria for significance rather liberally. A number of significant events and conditionally significant events were noted. The events initially identified as significant or conditionally significant were analyzed and evaluated further based on (1) engineering judgment; (2) the systems, equipment, or components involved; or (3) whether the safety of the plant was compromised. The final evaluation for significance considered whether a DBE was initiated or whether a safety function was compromised so that the system as designed could not mitigate the progression of events. Thus, the number of events finally categorized as significant was reduced considerably by these steps in the review process.

3.2.3 Reportable events that were not significant

Those reportable events not identified as significant or conditionally significant were categorized as not significant (with an "N" in the significance column of the coding sheets in the appendixes). These events and the events rejected during the additional review step were further reviewed by compiling a tabular summary of the systems to detect trends and recurring problems (Table 1.4 provides a listing of the systems).

Table 3.1. Initiating event descriptions for DBEs as listed in Chap. 15, *Standard Review Plan* (Revision 3)

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1. Increase in heat removal by the secondary system

   1.1 Feedwater system malfunction that results in a decrease in feedwater temperature
   1.2 Feedwater system malfunction that results in an increase in feedwater flow
   1.3 Steam pressure regulator malfunction or failure that results in increasing steam flow
   1.4 Inadvertent opening of a steam generator relief or safety valve
   1.5 Spectrum of steam system piping failures inside and outside of containment in a pressurized-water reactor (PWR)
   1.6 Startup of idle recirculation pump[a]
   1.7 Inadvertent opening of bypass resulting in increase in steam flow[a]

2. Decrease in heat removal by the secondary system

   2.1 Steam pressure regulator malfunction or failure that results in decreasing steam flow
   2.2 Loss of external electric load
   2.3 Turbine trip (stop valve closure)
   2.4 Inadvertent closure of main steam isolation valves
   2.5 Loss of condenser vacuum
   2.6 Coincident loss of onsite and external (offsite) ac power to the station
   2.7 Loss of normal feedwater flow
   2.8 Feedwater piping break
   2.9 Feedwater system malfunctions that result in an increase in feedwater temperature[a]

3. Decrease in reactor coolant system flow rate

   3.1 Single and multiple reactor coolant pump trips
   3.2 Boiling-water reactor (BWR) recirculation loop controller malfunction that results in decreasing flow rate
   3.3 Reactor coolant pump shaft seizure
   3.4 Reactor coolant pump shaft break

4. Reactivity and power distribution anomalies

   4.1 Uncontrolled control rod assembly withdrawal from a subcritical or low-power start-up condition (assuming the most unfavorable reactivity conditions of the core and reactor coolant system), including control rod or temporary control device removal error during refueling
   4.2 Uncontrolled control rod assembly withdrawal at the particular power level (assuming the most unfavorable reactivity conditions of the core and reactor coolant system) that yields the most severe results (low power to full power)
   4.3 Control rod maloperation (system malfunction or operator error), including maloperation of part length control rods

Table 3.1 (continued)

- 4.4 Start-up of an inactive reactor coolant loop or recirculating loop at an incorrect temperature.
- 4.5 A malfunction or failure of the flow controller in a BWR loop that results in an increased reactor coolant flow rate
- 4.6 Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant of a PWR
- 4.7 Inadvertent loading and operation of a fuel assembly in an improper position
- 4.8 Spectrum of rod ejection accidents in a PWR
- 4.9 Spectrum of rod drop accidents in a BWR

5. <u>Increase in reactor coolant inventory</u>

- 5.1 Inadvertent operation of emergency core cooling system during power operation.
- 5.2 Chemical and volume control system malfunction (or operator error) that increases reactor coolant inventory
- 5.3 A number of BWR transients, including items 1.2 and 2.1–2.6

6. <u>Decrease in reactor coolant inventory</u>

- 6.1 Inadvertent opening of a pressurizer safety or relief valve in either a PWR or a BWR
- 6.2 Break in instrument line or other lines from reactor coolant pressure boundary that penetrate containment
- 6.3 Steam generator tube failure
- 6.4 Spectrum of BWR steam system piping failures outside of containment
- 6.5 Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary, including steam line breaks inside of containment in a BWR
- 6.6 A number of BWR transients, including items 1.3, 2.7, and 2.8

7. <u>Radioactive release from a subsystem or component</u>

- 7.1 Radioactive gas waste system leak or failure
- 7.2 Radioactive liquid waste system leak or failure
- 7.3 Postulated radioactive releases due to liquid tank failures
- 7.4 Design basis fuel handling accidents in the containment and spent fuel storage buildings
- 7.5 Spent fuel cask drop accidents

8. <u>Anticipated transients without scram</u>

- 8.1 Inadvertent control rod withdrawal
- 8.2 Loss of feedwater
- 8.3 Loss of ac power
- 8.4 Loss of electrical load
- 8.5 Loss of condenser vacuum
- 8.6 Turbine trip
- 8.7 Closure of main steam line isolation valves

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[a]These initiating events were added for BWRs to be more specific than DBE events 5.3 and 6.6.

Table 3.2. NSIC event categories for non-DBE shutdowns

- N 1.0 Equipment failure
  - N 1.1 Failure on demand under operating conditions
    - N 1.1.1 Design error
    - N 1.1.2 Fabrication error
    - N 1.1.3 Installation error
    - N 1.1.4 End of design life/inherent failure/random failure
  - N 1.2 Failure on demand under test conditions
    - N 1.2.1 Design error
    - N 1.2.2 Fabrication error
    - N 1.2.3 Installation error
    - N 1.2.4 End of design life/inherent failure/random failure
- N 2.0 Instrumentation and control anomalies
  - N 2.1 Hardware failure
  - N 2.2 Power supply problem
  - N 2.3 Setpoint drift
  - N 2.4 Spurious signal
  - N 2.5 Design inadequacy (system required to function outside design specifications)
- N 3.0 Non-DBE reductions in coolant inventory (leaks)
  - N 3.1 In primary system
  - N 3.2 In secondary system and auxiliaries
- N 4.0 Fuel/cladding failure (densification, swelling, failed fuel elements as indicated by elevated coolant activity)
- N 5.0 Maintenance error
  - N 5.1 Failure to repair component/equipment/system
  - N 5.2 Calibration error
- N 6.0 Operator error
  - N 6.1 Incorrect action (based on correct understanding on the part of the operator and proper procedures, the operator turned the wrong switch or valve — incorrect action)
  - N 6.2 Action on misunderstanding (based on proper procedures and improper understanding or misinterpretation on the operator's part of what was to be done — incorrect action)
  - N 6.3 Inadvertent action (purpose and action not related, for example, bumping against a switch or instrument cabinet)
- N 7.0 Procedural/administrative error (incorrect operating or testing procedures, incorrect analysis of an event — failure to consider certain conditions in analysis)
- N 8.0 Regulatory restriction
  - N 8.1 Notice of generic event
  - N 8.2 Notice of violation
  - N 8.3 Backfit/reanalysis

Table 3.2 (continued)

N 9.0	External events
	N 9.1 Human induced (sabotage, plane crashes into transformer)
	N 9.2 Environment induced (tornado, severe weather, floods, earthquake)
N 10.0	Environmental operating constraint as set forth in Technical Specifications

Table 3.3. Reportable event criteria — significant

Category of significance	Event description
S1	Two or more failures occur in redundant systems during the same event
S2	Two or more failures due to a common cause occur during the same event
S3	Three or more failures occur during the same event
S4	Component failures occur that would have easily escaped detection by testing or examination
S5	An event proceeds in a way significantly different from what would be expected
S6	An event or operating condition occurs that is not enveloped by the plant design bases
S7	An event occurs that could have been a greater threat to plant safety with (1) different plant conditions, (2) the advent of another credible occurrence, or (3) a different progression of occurrences
S8	Administrative, procedural, or operational errors are committed that resulted from a fundamental misunderstanding of plant performance or safety requirements
S9	Other (explain)

Table 3.4. Reportable event criteria — conditionally significant

Category of conditional significance	Event description
C1	A single failure occurs in a nonredundant system
C2	Two apparently unrelated failures occur during the same event
C3	A problem results in an offsite radiation release or exposure to personnel
C4	A design or manufacturing deficiency is identified as the cause of a failure or potential failure
C5	A problem results in a long outage or major equipment damage
C6	An engineering safety feature actuation occurs during an event
C7	A particular occurrence is recognized as having a significant recurrence rate
C8	Other (explain)

4. OPERATING EXPERIENCE REVIEW OF BIG ROCK POINT

4.1 Summary of Operational Events of Safety Importance

The operational history of Big Rock Point has been reviewed to indicate those areas of plant operation that compromised plant safety. The review included a detailed examination of plant shutdowns, power reductions, reportable events, and events of special environmental importance. The criteria used to show degradations in plant safety were (1) events that initiated a DBE and (2) events that compromised safety functions designed to mitigate the propagation of the initiating events.

Shutdowns and power reductions indicated the number and types of DBEs entered. The reportable events and special environmental events indicated the number of times each engineered safety function was compromised. The analyses identified twenty-one DBEs entered. Additionally, five events were identified in which a loss of safety system function occurred.

4.2 General Plant Description

Big Rock Point Nuclear Power Plant is a General Electric boiling water reactor owned and operated by Consumers Power Company. The plant is located four miles northeast of Charlevoix, Michigan, on the Little Traverse Bay of Lake Michigan. There are no large population centers within sixty miles of the plant. Traverse City, with a population of 18,300, is the largest urban area near the plant at a distance of forty-five miles.

The reactor has a licensed thermal power of 240 MWt and a design electric rating of 72 MWe. Big Rock Point achieved initial criticality on September 27, 1962. The turbine generator was first sychronized to the tranmission system on December 8, 1962. The plant reached full temporary licensed power of 157 MWt on March 21, 1963. A permanent forty-year operating license for 240 MWt became effective on May 1, 1964. For the first four and one-half years of operation, Big Rock Point was a demonstration reactor for research and development of high power density fuel. Subsequently, it is still being used in the development of new reactor fuel types.

4.3 Availability and Capacity Factors

Table 4.1 presents the Big Rock Point availability and capacity factors [reactor availability, unit availability, unit capacity using the maximum dependable capacity (MDC), and unit capacity using the design electrical rating (DER)]. From 1966 through 1980, the reactor availability factor averaged 74.6% while the unit capacity factors, DER and MDC, averaged 57.9 and 60.7%, respectively. From 1966 through 1968, and 1972 through 1980, the average unit availability factor was 69.1%.

Availability and capacity factors were low during 1965, 1976, and 1979. The unit was shut down during the first seven months of 1965 for

Table 4.1. Availability and capacity factors for Big Rock Point

Average	1962-1963	1964	1965[a]	1966[a]	1967[a]	1968[a]	1969[a]	1970[b]	1971	1972
Reactor availability	d	d	14.8	75.1	83.7	81.5	89.7	90.5	96.7	80.0
Unit availability	d	d	14.6	73.6	81.8	80.2	d	d	d	79.9
Unit capacity (MDC)[c]	d	d	13.2	60.5	75.7	68.8	67.3	64.6	59.3	70.7
Unit capacity (DER)[e]	d	d	13.0	59.7	74.6	67.8	66.4	63.7	58.5	69.7

Average	1973	1974	1975	1976	1977	1978	1979	1980	1981	Cumulative
Reactor availability	80.0	70.8	60.3	51.4	74.1	78.9	24.0	79.2	91.4	70.0
Unit availability	79.9	70.3	59.8	50.1	73.4	77.9	23.5	78.9	90.6	68.6
Unit capacity (MDC)[c]	67.9	54.3	46.7	39.2	63.4	71.9	20.6	71.5	83.6	56.8
Unit capacity (DER)[e]	67.0	53.5	46.1	38.7	57.2	63.6	18.0	64.1	74.5	53.2

[a] November to November

[b] November 1969 to December 1970

[c] MDC = Maximum Dependable Capacity

[d] No Data (ND)

[e] DER = Design Electrical Rating

analyses, testing, and repair work on the thermal shield hold-down assemblies. The lower values for 1976 were due to a refueling outage, installation of the reactor depressurization system, and modification of the emergency core cooling system. In 1979, the plant shut down for 5000-hours to correct problems with the inlet diffusers.

4.4 Forced Reactor Shutdown and Forced Power Reduction

4.4.1 Review of forced reactor shutdowns and forced power reductions

From startup in September 1962, through December 31, 1981, Big Rock Point experienced 124 forced shutdowns and sixty-nine forced power reductions. Tables A1.1 through A1.19 present a compilation of data describing each forced shutdown and power reduction. Limited information was available for 1962 through 1965. Tables 4.2 and 4.3 summarize the forced shutdowns and forced power reductions.

The consequences of forced shutdowns and power reductions could just be the inability to produce power. However, some shutdowns or power reductions safety implications called design basis events (DBEs). DBEs are postulated failures resulting in system transients that challenge one or more safety systems. Since DBEs challenge safety systems and are the initiating events in postulated accident sequences, they warrant special attention.

4.4.1.1 Yearly summaries. The following is a discussion of forced shutdowns, forced power reductions and other important events by year for 1962 through 1981.

1962-1963

Criticality was first achieved on September 27, 1962, twenty-nine months after initial ground breaking. The initial full power rating of 157 MWt was reached on March 21, 1963.

During pre-startup in December 1962, resins were inadvertently introduced into the primary coolant water and thus into the control rod drive water. Although attempts were made to remove the resins, troubles were still encountered with the rod drives and it was necessary to remove the fuel from the reactor vessel for cleaning. This event revealed problems with the reactor inlet diffuser design and the cap screws from a tube and channel assembly.

1964

All three forced shutdowns that occurred in 1964 were due to equipment failures. Two were due to spurious openings of the turbine bypass valve. A spurious trip of nuclear instrument channel 2 during testing of channel 1 caused the third shutdown.

Power operation ceased in February in order to reload the eighty-four fuel bundles and to inspect the turbine generator. The generator required rewinding of the generator field. Power operation and further testing resumed on May 21.

The reactor was shut down on July 13 for a gamma scan of the core and to reload the core using forty-four fuel bundles. Another shutdown occurred from August 26 to September 15 to inspect core internals in an attempt to find the cause of observed flux oscillations.

Table 4.2. Big Rock Point forced shutdown summary

	1962-1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
I. Forced shutdowns																				
1. Total number	19	3	3	13	9	13	9	10	9	12	2	1	3	3	1	5	4	4	1	124
2. Total hours down				514	543	259	233	190	210	341	97	1045	3516	3299	88	1941	5239	335	52	17,902
3. Cause[a]																				
A. Equipment failure	6	2	4	12 (490)	9 (537)	11 (232)	9 (209)	8 (108)	6 (157)	10 (320)	3 (97)	3 (1045)	2 (95)	2 (84)	1 (68)	4 (1919)	5 (5237)	4 (39)	1(52)	102 (10,709)
B. Maintenance or testing	9	1			1 (6)	1 (21)				1 (13)										13 (40)
D. Regulatory restriction													1 (3421)	1 (3215)			1 (2)	1 (296)		4 (7234)
G. Operational error	2					1 (6)	1 (24)		1 (18)	1 (8)										6 (56)
H. Other				1 (24)				2 (82)	2 (35)							1 (22)				6 (163)
4. Shutdown method																				
1. Manual	3		2	12	6	12	9	7	6	9	2	1	3	2	1	2	2			79
2. Manual scram	2															1	1			4
3. Automatic scram	14	3	1	1	3	1		3	3	3				1		2	1	4		40
4. Continuation			1		1		1				1	2					2	1		9
9. Other																			1	1
II. Total number of DBE related shutdowns (These are included in Totals of Part I)	3		1	1	1			2	4	3				1		2		1		19
Reactor vessel internals (RA)																	1			1
Reactivity control systems (RB)	1		1	1	2	5	3			3		1				2				19
Reactor vessel (CA)						2														2
Coolant recirculation systems (CB)	1			2		1	1		2	2							1			10
Main steam systems (CC)				1	2													1		4
Reactor coolant cleanup systems (CC)											1									1
Feedwater systems (CH)	1			8			1			2	1									13
Reactor containment systems (SA)																	1			1
Containment heat removal systems (SB)								1			1		1			1				4
Emergency core cooling systems (SF)														1						1
Core spray system (SF-D)							1	1												2
Reactor trip systems (IA)	7	1			2	1		1										3		15
Engineered safety feature instrument systems (IB)																	1			1
Electric power systems (EX)	1									1										2
Offsite power systems (EA)			1	1				2	2							1				7
AC onsite power systems (EB)									1							1				2
Steam and power conversion systems (HX)					1															1
Turbine-generators (HA)	3		2		2		4	3	3	1			1	1	1				1	22
Main steam supply systems (HB)	1						1			1										3
Main condenser systems (HC)						1	1	1	1				1							5
Turbine bypass systems (HE)	4	2				1				1							2			10
Condensate cleanup systems (MC)						1														1
Condensate and feedwater systems (HH)												1								1
Gaseous radioactive waste management systems (MB)					1	1		1		1				1						5

[a]When available, the number of hours associated with the cause of the shutdown is in parentheses.

Table 4.3. Forced power reduction summary for Big Rock Point

	1962-1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
I. Power Reduction																				
1. Total Number	0	0	0	5	9	6	2	1	2	6	10	7	6	1	2	3	0	6	3	69
2. Cause																				
A. Equipment failure				5	9	6	2		2	5	7	7	4	1	1	1		6	1	57
B. Maintenance or testing								1		1	3								2	7
F. Administrative													1							1
H. Other													1		1	2				4
II. Total number of DBE related power reductions (these are included in Totals of Part I				1														1		2
III. Systems involved																				
RX Reactor																				
RB Reactivity control													1			1			1	3
RC Reactor core				3	1	3	2			1	3	2								15
CX Reactor coolant										1										1
CB Coolant recirculation and controls				1					2	2								1		6
CC Main uteam system and controls				1	2													1		4
CG Reactor coolant cleanup and controls										2	2							1		5
CH Feedwater systems and controls				1		3						1		1	1					7
IX Instrumentation and controls																				
IB Engineered safety feature instrumentation											1									1
ID Safety-related display instrumenation												1								1
EX Electric power																				
EA Offsite power and controls													1			1				2
EB AC onsite power and controls											2									2
WX Auxiliary water																			2	2
WB Cooling system for reactor auxiliaries and controls											2									2
HX Steam and power conversion																				
HA Turbine-generators and controls					6								2		1			2		11
HC Main condenser and controls												3	1							4
HE Turbine bypass and controls													2					1		3
MX Readioactive waste management																				
MA Liquid radioactive waste management								1												1
XX Other systems																1				1

On September 18, a scram occurred due to a spurious opening of the turbine bypass valve. During startup and routine control rod tests following the scram, operators noticed evidence of galling of the rod drives. An examination of internals revealed foreign particles had lodged between the index tube and the upper guide sleeve of the control rod drives. While inspecting the control rod blades, six thermal shield hold-down studs were found to be cracked. The unit remained shut down for the remainder of the year to investigate methods of repair.

<u>1965</u>

In 1965, there were three forced shutdowns. All three (and one continuation of a forced shutdown) resulted from equipment failures.

The 1964 shutdown for thermal shield modifications continued until September 4, 1965. After startup, the reactor operated at full power for the remainder of the year. On September 17, a load rejection occurred due to a relaying malfunction. The plant shut down for several days to repair turbine steam leaks and modify twenty-two control rods.

<u>1966</u>

Twelve of the thirteen forced shutdowns in 1966 resulted from equipment failures. The thirteenth occurred when off-site power was lost during a storm. All five of the forced power reductions resulted from equipment failures.

On August 3, the plant was shut down for the eighth time because of tube leakage in the high-pressure feedwater heater. At this time, the heater tube sheet was blanked and the water box divider tube removed. Permanent piping allowed the feedwater to bypass the heater and thus eliminate the tube leak problem.

Fuel cladding failures necessitated reducing the plant power level from 97% to 83% on February 10 until the refueling outage in April. Following startup in May, the activity in the off-gas continued to increase indicating additional fuel cladding failures. Consequently, power was reduced to 89% on June 2; to 75% after the feedwater heater outage on June 18; and to 49% from July 26 until the refueling outage in September. Following refueling, the plant was operated at reduced power for the remainder of the year due to a seal failure on the No. 2 reactor recirculating pump.

<u>1967</u>

In 1967, there were nine forced shutdowns and nine power reductions. Eight of the forced shutdowns resulted from equipment failures and one was due to maintenance and testing. All nine of the power reductions were due to equipment failures. The plant operated at full power until January 20, when the reactor scrammed due to difficulty with the initial pressure regulator (IPR). Power reductions were made during February in order to make repairs on the IPR. The IPR functioned satisfactorily after the repairs were made on February 17.

After the May refueling, only two shutdowns for operator training and examination interrupted the plant from operating continuously until October 26. Failure of fuel elements necessitated power reductions in December.

1968

There were thirteen forced shutdowns and six power reductions in 1968. Eleven of the shutdowns resulted from equipment failures, one was due to maintenance and testing, and one was due to an operational error. All six of the power reductions were due to equipment failures. The plant was operated in the "all-rods-out" core configuration until the refueling outage in February. The plant resumed operation on March 15. However, due to problems with the lower bearing in recirculating pump No. 2 necessitated operation to resume with only one recirculation pump. Following the pump repairs in early April, control rod drive B-4 could not be withdrawn from the fully inserted position. The control rod drive was replaced. Plant operation resumed on April 9 but the load was derated until the June 21 refueling outage. Fuel cladding failed on several of the old fuel bundles used to reconstitute a full eighty-four bundle core. Following the startup, the plant operated around 90% of full power with no significant difficulties until December 14. Fuel cladding failures again necessitated a power reduction (to 83%).

1969

There were nine forced shutdowns in 1969 of which eight resulted from equipment failures. An operational error caused the ninth. Both of the power reductions were due to equipment failures.

The plant continued to operate at a reduced load due to fuel cladding failures. An "all-rods-out" coast down started on April 10. Refueling began on April 18 and power operation resumed on May 9. Due to premature failure of several "E" fuel bundles, the plant operated around 69% power for the rest of the year.

High conductivity of the primary coolant due to previous overheating of the demineralizer resin caused one shutdown. The remainder of the forced shutdowns were due to steam or cooling system leaks.

Members of the company-wide union were on strike from April 8 to June 30. Supervisory personnel, engineers and technicians performed refueling operations, necessary maintenance, and operation of the plant during this period.

1970

Eight of ten forced shutdowns in 1970 resulted from equipment failures. Faults in the transmission line external to the plant caused the other two forced shutdowns. The only power reduction occurred as a result of maintenance operations.

The plant continued to operate at reduced power because of the fuel failures in 1969. During the six-week refueling outage starting on February 13, personnel conducted a turbine inspection, installed a control rod drive support structure, installed portions of the redundant core spray system, and performed the containment leak rate test. On June 28 and December 3, high pressure trips occurred because of load rejections caused by faults in the 138 kV transmission line. Both load rejections were results of severe storm conditions in the area.

1971

There were nine forced shutdowns and two power reductions in 1971. Six resulted from equipment failures, one was due to an operational error, one due to a local storm, and the other was apparently due to sabotage. The apparent sabotage occurred on the first day members of the company-wide union strike (May 12 to September 1).[15] Supervisory personnel, engineers, and technicians operated the plant. The reactor scrammed due to load rejection resulting from a fault in the 138 kV transmission line. The fault resulted when a corner strain pole fell into the adjacent two phases of the power line. The strain pole was cut approximately half way through the thickness of the pole. In addition, the guy line to the pole had been cut.[15] A local storm caused a scram on September 28. Another forced shutdown and the two forced power reductions resulted from defective recirculating pump seals.

The plant continued operation into 1971 at 70% due to premature failure of several "E" fuel bundles. On January 23, the plant shut down to repair turbine condenser leaks. During testing of the containment isolation valves prior to startup, the main steam drain line isolation valve (outside containment) failed to close. The cause was a defective solenoid due to moisture in the instrument air. Personnel replaced the instrument air dryer and four similar valves during the February refueling outage. Also, during the February outage, installation of the redundant core spray system, begun in 1970, was completed and two in-core detector assemblies were replaced.

1972

There were twelve forced shutdowns in 1972. Ten of these resulted from equipment failures, one occurred during testing, and one was due to an operational error. Five of the six forced power reductions resulted from equipment failures. The sixth occurred during maintenance.

A turbine trip occurred on January 25 following a line fault on the offsite 138 kV electric system which was not cleared by the Big Rock Point relaying scheme. As a result, the plant became momentarily isolated from the rest of the 138 kV transmission grid with essentially no load. Concurrently, the redundant 46 kV offsite power supply was also lost due to unusual weather conditions. The diesel generator started and supplied plant loads.

The plant operated in the coastdown mode from January 4 until the refueling shutdown on March 18. During the shutdown, personnel replaced the clean-up systems' heat exchangers the contained Cufenloy tube bundles. The new heat exchangers utilized stainless steel tube bundles in an attempt to eliminate crud deposits on the fuel cladding. This change was made in order to decrease the rate of premature cladding failures.

After several miscellaneous equipment failures caused power reductions or shutdowns, power increased to 83% on July 6 and essentially remained at this level until December 30. On December 30, increased activity levels in the off-gas due to fuel cladding failures required a power reduction to 68%.

1973

There were only two forced shutdowns in 1973. Both resulted from equipment failures. There were ten forced power reductions that resulted from equipment failures (7), maintenance (2), and testing (1).

The plant operated in the coastdown mode until March 3 when it was shut down for refueling. Crud deposits on the fuel cladding appeared to be lower than that observed during previous cycles.

In the middle of April, power operation resumed at 92% of full power. Power remained at this level until December 3 when it was reduced to 76% due to high off-gas activity from fuel cladding failures. Another power reduction (to 70%) was necessary on December 6 because of high off-gas activity.

On December 8, the unit was forced off-line due to a packing failure on the reactor steam drum level instrument valve. The plant remained down for the rest of the year to repair the leaking emergency condenser.

1974

There were one forced shutdown and seven forced power reductions in 1974. All resulted from equipment failures.

After completing the repairs to the emergency condenser, the plant was returned to service at 50% power. On January 12, a special operational test was successfully completed on the emergency condenser to assure adequate cooling capacity. The power was raised to 70% and was maintained at this level until the refueling outage starting on March 23.

Following startup, an attempt to achieve 100% power failed. The stop on the initial pressure regulator limited power to 98%. After three hours operation at this power level, a reduction to 93% was initiated due to flooding of the intermediate pressure feedwater heater and condenser vacuum upset. Power reductions on May 17 and 20 were necessary due to fuel cladding failures.

On October 6, an incore detector failed leaving only ten detectors operational. During the placement of the plant into the coastdown mode (November 5 through November 26), a reevaluation of the administrative limit resulted in raising the thermal-hydraulic limit from 80 to 90% of the technical specifications. Operation resumed at 83% on November 26 and remained at this level for the remainder of the year.

1975

Of the three forced shutdowns in 1975, two resulted from equipment failures and one was due to regulatory restrictions. There were six forced power reductions. Four resulted from equipment failures, one was administrative, and one was for modification of an external substation.

The plant continued to operate at 83% full power until January 7. Encroachment on the 90% maximum average planar linear heat generation rate (MAPLHGR) limit on "F" type fuel led to a reduction to 80%. On January 16, approximately one week prior to the scheduled semiannual outage, the plant shut down when studies revealed that there was a design deficiency in the instrumentation for the post-incident cooling system. Modifications, as a result of the special task force investigation, were completed by the first week of June, at which time power operations were resumed. The power fluctuated around 80% until October 18 when modifications to the

Livingston substation required a power reduction. While at reduced power, the initial pressure regulator (IPR) failed and the synch-governor control carried a load of 68% until October 24 when repairs on the IPR controls were completed. On October 30, the IPR failed again due to a malfunction in the control system involving a valve bellows.

<u>1976</u>

There were three forced shutdowns in 1976. Two resulted from equipment failures and one was due to regulatory restrictions. The single forced power reduction resulted from equipment failure.

Work during the six-month outage starting on January 31 included refueling, and installation and startup of the reactor depressurization system. Also included were several minor modifications to the emergency core cooling system (ECCS). On July 28, the 14th cycle began but a power limit of 88% of rated power was imposed due to loss of coolant accident (LOCA) peak clad temperature restrictions. Operation from August throughout the remainder of the year was essentially continuous.

<u>1977</u>

Only one forced shutdown was required in 1977. This shutdown and one of the two forced power reductions resulted from equipment failures. The second power reduction was necessary in order to investigate noise in the No. 2 reactor feed pump.

Operations continued at 85% of full power for the first part of the year with only two minor power reductions. When the plant shut down July 23 for refueling, it had accumulated 343 days of continous operation. After operations resumed, power generation was interrupted only once through the remainder of the year when turbine control problems resulted in an eighty-eight hour outage in October.

<u>1978</u>

There were five forced shutdowns in 1978. Four resulted from on-site equipment failures and one was due to a substation wiring error. One of the three forced power reductions resulted from on-site equipment failure. The remaining two were due to substation and relaying difficulties.

The plant operated most of the year around 90% of full load. Control rod drive problems accounted for 1765 hours of outage time. Two shutdowns and two power reductions involved substation or tone relaying troubles.

<u>1979</u>

Of the four forced shutdowns in 1979, three resulted from equipment failures and one was due to regulatory restrictions. There were no forced power reductions.

The plant operated at 82% of full power until the start of the refueling outage on February 3. During the outage, maintenance personnel reworked the welds on the new core spray ring.

On April 17, while at low power, the turbine bypass valve failed to open causing a high pressure trip. Subsequent testing revealed a reactor inlet diffuser vibration problem. Reactor vessel repairs were not completed until November 4 when power operation was resumed. Another shutdown was required on November 6 to replace a recirculating pump, repair incore flange leaks, and repair leaks in the turbine bypass drain line.

On December 31, a shutdown began to address Three Mile Island (TMI) 2 concerns. Modifications provided indication of the relief valve position, the ability to manually reset containment isolation valves, and a radiation monitor for assessing core damage.

<u>1980</u>

All four forced shutdowns and all six of the forced power reductions in 1980 resulted from equipment failures. The short-term lessons-learned changes required by NUREG/0578 (Ref. 14) because of the TMI 2 accident were completed and the plant returned to operation on January 13. A forced shutdown occurred on January 15 due to failure of the initial pressure regulator (IPR). The plant operated at about 88% of full load until the refueling outage which commenced on October 31. During this period, there were six forced power reductions including one which resulted from the loss of a reactor recirculating pump.

<u>1981</u>

The refueling outage was extended on February 2 due to problems with the generators' exciter. The outage lasted an additional 52 hours and was the only forced shutdown for the year. Three power reductions were made in order to replace a cleanup pump, perform maintenance on the pump, and complete control rod drive performance tests. Other than the extended refueling outage and the three power reductions, the plant operated at 100% power throughout the year. This was reflected in the unit availability of 90.6% and a reactor availability of 91.4%.

4.4.1.2 <u>Systems involved.</u> Tables 4.2 and 4.3 present yearly summaries of the forced shutd[illegible]orced power reductions that occurred at Big Rock Point. As [illegible] the tables, the systems involved in forced shutdowns and p[illegible]ctions were dominated by three systems. The three systems [illegible]pproximately 80% of the 193 forced outages and power reductions. [illegible]ee systems are the reactor system (39 events), reactor c[illegible] sy[illegible]1 events), and the steam and power conversion system ([illegible]

Each [illegible]stem categories contains subsystems. Over half of the reacto[illegible] forced shutdowns and power reductions were due to failures in [illegible]ivity control system (RB). Mechanical failures of the control r[illegible]ves or leaks in the control rod drive system caused most of these failures. The reactor core system (RC) was not responsible for any forced shutdowns but was responsible for fifteen of the power reductions. These reductions were required due to fuel cladding failures (see Sect. 4.4.3.1).

The forced shutdown and power reductions involving the reactor coolant systems were dominated by failures in the coolant recirculation system (CB) and the feedwater systems (CH). Seventeen outages and power reductions were attributed to the recirculation system with eight of these resulting from leaking recirculating pump seals. Leakage in the feedwater heater caused seven of the twenty feedwater system events.

Of the sixty-one forced shutdowns and power reductions in the steam and power conversion system, thirty-four occurred in the turbine generator and controls system (HA). Of these, thirteen were due to steam leaks in various parts of the system and ten were due to difficulties with the initial pressure regulator. Six of the initial pressure regulator outages occurred within the first two months of 1967. After cleaning and adjusting the regulator on February 17, no failures were reported until 1970.

4.4.1.3 Causes of forced reactor shutdowns and forced power reductions. As well as presenting yearly summaries of forced shutdowns and power reductions for systems, Tables 4.2 and 4.3 also present yearly summaries for causes of these events. Equipment failures dominated the causes for forced shutdowns and power reductions (81%). Approximately half of the equipment failures were due to leaks in piping, heat exchanger tubes, valve packings, and pump seals. Only fourteen percent were caused by human errors with the majority of these caused by maintenance and testing errors. The remaining causes ("others" in the tables) accounted for five percent percent of the events and were adverse environmental conditions.

4.4.1.4 Non-design basis events. There were 181 forced shutdowns or forced power reductions which were not categorized as DBE initiating events (Table 4.4). Eighty of the 181 forced shutdowns or forced power reductions were assigned to NSIC event category 1.0 event types - Equipment Failure; nineteen were category 2.0 event types - Instrument and Control Anomalies; fifty-two were category 3.0 event types - Non-DBE Reduction in Coolant Inventory; fifteen were category 4.0 event types - Fuel/Cladding Failure; one was a category 5.0 event type - Maintenance Error; four to 6.0 - Operator Error; one to 7.0 - Procedural/Administrative Error; four to 8.0 - Regulatory Restriction; and five to 9.0 - External Event.

4.4.2 Review of design basis events

Design basis events (DBEs) are transients which challenge the safe operation of a plant and the ability of engineered safety features to safely shut the plant down. Big Rock Point has experienced twenty-one forced shutdowns or forced power reductions caused by DBE initiating events (Table 4.5). This section discusses the forced shutdown and forced power reductions by DBE category.

4.4.2.1 DBE category 2 - decrease in heat removal. The seventeen events in category 2 were of five types:

1. DBE 2.1 Steam pressure regulator malfunction or failure that resulted in decreasing steam flow (3).
2. DBE 2.2 Loss of external load (9).
3. DBE 2.3 Turbine trip (3).
4. DBE 2.5 Loss of condenser vacuum (1).
5. DBE 2.7 Loss of normal feedwater flow (1).

All of these events were followed by a safe reactor shutdown. In one type 2.3 event (11/26/71), the turbine generator tripped. However, there was no scram since the condenser and turbine bypass valves were able to handle the load. All other category 2 events resulted in automatic scrams.

Table 4.4. Non-DBE initiating event summary

Description	1962-1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1.0 Equipment Failures	4	2	3	3	10	11	4	5	4	8	3	4	3	1	1	4	4	2	4	80
2.0 Instrumentation and Control Anomalies	8			1	1			2		1	2				1			3		19
3.0 Non-DBE Reductions in Coolant Inventory (Leaks)				10	5	4	7	2	3	5	3	3	4	1	1		1	3		52
4.0 Fuel/Cladding Failure				3	1	3	2			1	3	2								15
5.0 Maintenance Error					1															1
6.0 Operator Error	2					1	1													4
7.0 Procedural/Administrative Error		1																		1
8.0 Regulatory Restriction													1	1			1			4
9.0 External Events											2		1			2				5
10.0 Environmental Operating Constraint - Tech Specs																				
Total	14	3	3	17	16	19	14	9	7	15	13	9	10	3	3	6	6	8	4	181

Table 4.5. DBE initiating event summary

DBE category	Description	1962-1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
2.1	Steam pressure regulator malfunction or failure that results in decreasing steam flow					1									1				1		3
2.2	Loss of external electrical load			1	1				2	2	1						2				9
2.3	Turbine trip	1								2											3
2.5	Loss of condenser vacuum	1																			1
2.7	Loss of normal feedwater flow										1										1
3.1	Single and multiple reactor coolant pump trips				1														1		2
4.3	Control rod	1									1										2
Total		3	0	1	2	1	0	0	2	4	3	0	0	0	1	0	2	0	2	0	21

Two of the three DBE 2.1 events (steam pressure regulator malfunction) were caused by failures of the initial pressure regulator (1967, 1976). The third event was caused by the failure of an intermediate pressure regulator (1980).

Electrical storms caused five of the nine scrams caused by a DBE 2.2 type events-loss of external electrical load, for example, the 138 kV line (Table 4.6). Two of the DBE 2.2 type events were due to relaying malfunctions, and one was due to wiring errors at an offsite substation. The ninth was apparently due to sabotage. A guy wire had been cut and a corner strain pole had been sawed approximately halfway through.

Two of the three DBE 2.3 type events (turbine trip) occurred in 1971. Accidental tripping of the 2400-volt station power breaker (September 22, 1971) caused a loss of power to most major equipment and subsequent turbine trip and rod scram. Failure of the linkage arm of the turbine trip solenoid on November 26, 1971 caused a turbine trip. The load was carried by the bypass valve and condenser until the reactor was manually shut down for repairs to the linkage.[16] The fourth DBE 2.3 event occurred on February 20, 1963, and the only information available is that there was a momentary generator loss.

The single type 2.5 event (loss of condenser vacuum) occurred in 1963. A low vacuum scram resulted from loss of station power.

The only type 2.7 event was caused by inadequate feedwater supply during a load rejection test on July 6, 1972. This caused a reactor and turbine trip.

4.4.2.2 <u>DBE Category 3 - decrease in reactor coolant system flow rate.</u> Both events in category 3 were caused by the loss of one of the reactor coolant pumps (Type 3.1 event "single and multiple reactor coolant pump trips"). One of these was due to a leaky seals (also see 4.4.3.2), while the cause of the third one is unknown.

4.4.2.3 <u>DBE category 4 - reactivity and power distribution anomalies.</u> The two events in DBE Category 4 were type 4.3 - control rod maloperation. All occurred at low power. The first was on February 17, 1963. Demineralizer resin was accidentally released into the primary system and caused a malfunctioning of the rod collet fingers. The second event occurred on November 12, 1972, when a short period scram occurred because of high notch worth in the withdrawal sequence. A new control rod withdrawal sequence was developed to minimize this difficulty.

4.4.3 <u>Trends and safety implications of forced reactor shutdowns and forced power reductions</u>

4.4.3.1 <u>Summary of events relating to fuel element cladding failure.</u> Big Rock Point is a high power density reactor which has been involved in a developmental program for high performance fuel elements. Its license permits insertion of powdered or pelletized fuel elements with Inconel, Incoloy, and Zircoloy cladding.

Big Rock Point experienced considerable difficulties with failed fuel element cladding and these experimental elements accounted for a number of the failures. However, the fuel element cladding failures did not pose any real safety problems. Power reductions kept the off-gas activity within acceptable limits.

Table 4.6. External power source failures at Big Rock Point

Report number	Event date	Cause	Description
	091765	Relay failed	Off-site power was lost when a relay malfunctioned.
66-3	080866	Storm	Off-site power was lost when a storm caused the loss of the 138 kV line.
	062870	Storm	138 kV line lost during a storm.
	120370	Storm	138 kV line lost during a storm
	061271	Union strike	138 kV line lost when strain pole fell across two phases of the power line.
	092871	Storm	138 kV line lost during a storm.
72-1	012572	Storm	Off-site power lost during storm, relay scheme failed to clear fault.
R07818	040778	Relay failed	An oil circuit break opened even though 138 kV line was still energized.
R07822	053178	Faculty wiring	138 kV line unavailable due to wiring error in substation.

Crud buildup was found during most of the early fuel inspections. Chemical analysis showed that the crud consisted mainly of zinc, nickel, iron and copper, which were constituents of the feedwater heater tube material. Therefore the copper nickel tubes were replaced with stainless steel in 1968. However, crud buildup and tube failures continued. These were attributed to "hide out" of inventory material in the system and from "fluffing" of the demineralizers plus new material from the cleanup heat exchangers. This resulted in the replacement of the heat exchangers in April 1972.

Flow tests indicated that flow pattern difficulties caused regions of higher power in the fuel rods. To correct this, fuel channel-orifice hardware on sixty-nine of the eighty-four fuel support-tube-and-channel assemblies were replaced in 1972 and 1973. The combination of the aforementioned corrective actions resulted in lower off-gas activity levels and a reduction in fuel element failures.

The first indication of possible leaking fuel cladding was evident on September 4, 1965 when the off-gas activity started to increase. From mid-September through mid-October, the off-gas activity increased exponentially to a rate of about 15,000 μCi/s, and then showed signs of leveling off. This level remained essentially constant since November 1, 1965. However, on February 10, 1966, the off-gas activity rate of release reached 50,000 μCi/s. This increasing release rate indicated an increased deterioration of the fuel cladding. Therefore, power was reduced from 70 to 60 Mwe (net) to reduce fuel deterioration.

During the April refueling outage, four (out of thirty) bundles were found to have gross defects. One rod had approximately eight inches of fuel missing below the middle spacer. There was no significant amount of crud buildup.

Following the startup in May 1966, the activity in the off-gas continued to increase. Due to high off-gas activity, power was reduced to 64 MWe on June 2, to 54 MWe on June 19, and to 35 MWe on July 26.

During the September 1966 shutdown, dry sipping located eleven failed bundles in the central core region. Four developmental Incoloy-800 clad bundles were the primary source of activity. These failures were not expected since the lead bundle of this group only had an approximate 7000 MWd/T exposure (designed for 15,000 Mwd/T). Three other elements failed grossly due to longitudinal splits in cladding or to circumferential cracks at pellet interfaces. The other identified elements had very low leakage signals and were visually inspected. It appears that failure was due to intergranular stress corrosion, similar to that experienced with other stainless steel clad material.

Prior to the May 19, 1967 shutdown for refueling, the off-gas activity rate had been steady at 800 μc/s. This indicated no gross fuel failures in the core. Dry sipping indicated a 19 mil Incoloy 800 clad developmental bundle (D-4) as a leaker. This bundle was eliminated from subsequent core loading. It was also noted that several fuel elements had 1-3 mils of crud buildup since October 1966.

In early December 1967, plant load was reduced after off-gas activity rates increased from 13,000 to 21,200 μc/s. This reduction was made to preserve fuel integrity.

Refueling started February 11, 1968. Twenty-nine of the thirty-three reload-2 "C" fuel bundles indicated a positive leaking signal after being dry sipped.[17] These were vibratory packed powdered fuel. Impurities on the fuel particles reacted chemically with the cladding to form local blisters of zirconium hydride. These blisters breached the cladding. Th copper, nickel tubes of the feedwater heater were replaced with stainless steel tubes during this shutdown. The feedwater heater tubes were replaced since chemical analysis of the fuel rods showed the crud consisted mainly of zinc, nickel, iron and copper. These were constituents of the feedwater heater tube material.

On June 9, 1968, off-gas activity again started to increase. The activity rate rose from 3400 to 14,000 μc/s indicating fuel failure. Plant load was reduced on June 12 and 13 to 57 MWe (gross) and 52 MWe (gross), respectively. A power increase to 60 MWe (gross) was made on June 21, 1968 to satisfy requirements set forth in the centermelt fuel program. Off-gas activity increased to 11,000 μc/s during this power increase. Shutdown for refueling began after this test. Two standard stainless steel clad fuel elements, two zirconium-clad powder elements, and two of six centermelt fuel elements indicated positive leak signals after being dry sipped. During refueling, forty-one "E" bundles were loaded. These were pellet UO_2 rather than the "C" powder UO_2 elements that failed early.[14]

During the last week of October 1968, off gas activity rate increased from 3700 to 12,500 μc/s indicating clad failure in the new core. Power was reduced to 68 MWe (gross) on December 14, to 62 MWe (gross) on January 2, 1969 and to 53 MWe (gross) on February 18, 1969 to lower off-gas activity.

Refueling started April 18, 1969 and eighty-two of eighty-four assemblies were dry sipped. Nine failed assemblies were found. Intermediate performance centermelt assembly (D-50) severely failed. Three out of thirty "B" assemblies, and two of ten "C" UO_2 powder assemblies also failed. Additionally, three of the forty-one "E" UO_2 pellet assemblies unexpectedly failed.[19] The two powdered UO_2 fuel rods that failed (D-54, D-55) were next to the calculated hottest rod in each of the bundles (Figs. 4.1 and 4.2).[20] These rods were also shrouded by the corner angle piece. The other compacted UO_2 powdered fuel rods in equivalent positions did not exhibit the severe crud spalling as the failed powdered rods did. However, all of the failed assemblies exhibited significant crud accumulation and crud spalling (including the centermelt assembly D-50). Hot cell examinations were conducted on two fuel rods from the intermediate performance centermelt assembly D-50. Accelerated corrosion on the rods outside surface, driven by local overheating, caused the severe clad deterioration. Since the preliminary investigations showed accelerated corrosion due to high cladding temperatures, subsequent power operation was temporarily limited to 165 MWt.

The stainless steel cleanup heat exchangers replaced their copper nickel predecessors in 1972. The poor core flow distribution was corrected in 1972 and 1973. Since then, the crud buildup has decreased and the number of fuel failures have decreased considerably even while operating at higher power levels.

4.4.3.2 <u>Summary of reactor recirculating pump failures.</u> The shaft seals of the reactor recirculating pumps failed ten times between 1966 and 1981. A new type cartridge seal was installed during the February 1968

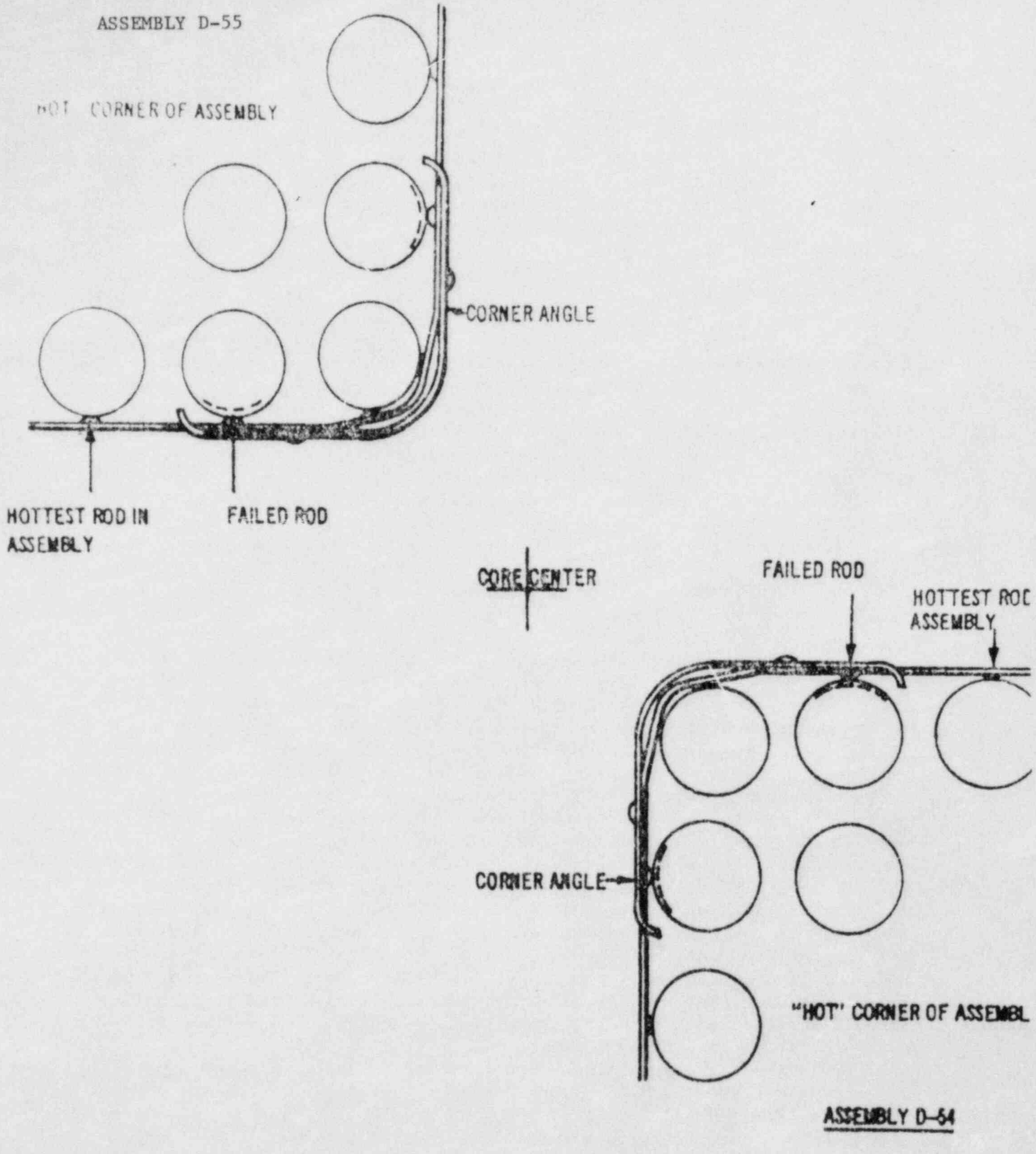

Fig. 4.1. Location of the failed compacted powder UO_2 fuel rods.

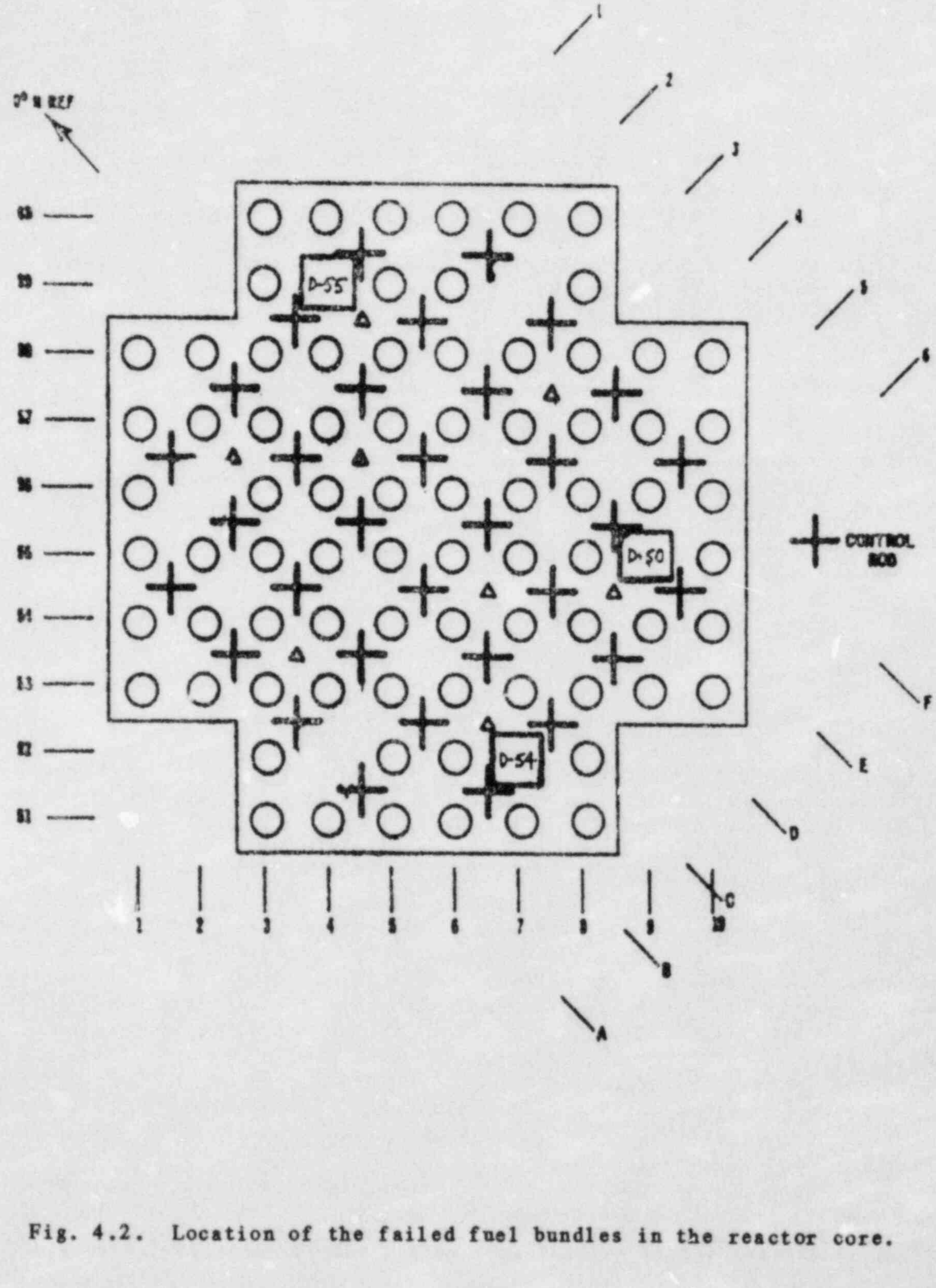

Fig. 4.2. Location of the failed fuel bundles in the reactor core.

refueling outage. This had to be replaced shortly after startup due to inadequate seal leak off flow. However, the new type seal cartridges were easier to replace and resulted in shorter duration shutdowns. Until the middle of 1972, the rate of seal failure remained about the same. There have only been two losses of reactor recirculating pumps since 1972.

4.5 Reportable Events

This review of the operating history at Big Rock Point included a study of 366 reportable events which were submitted to the AEC and NRC concerning technical specification violations and limited conditions of operation. These reports came in the form of letters, telegrams, abnormal occurrences (AO's), reportable occurrences (RO's), and licensee event reports (LERs). The reports were reviewed and coded as per Sect. 1.3 and are arranged by year in Part 2 of Appendix A.

4.5.1 Review of reportable events from 1966 to 1980

Although Big Rock Point achieved initial criticality in 1962, this review found no reports prior to 1966 containing reportable event type of information. Events prior to 1966 were obtained from letter correspondence between the AEC and Consumers Power Company. Figure 4.3 illustrates a histogram of reports filed by Big Rock Point for 1966 to 1981. Environmental reports are discussed in Sect. 4.5.1.4.

4.5.1.1 Yearly summaries. The following sections present a summary of reportable events for each year at Big Rock Point.

Prior to 1966

Big Rock Point had trouble with the control rod drives beginning in 1962 when the reactor first went critical. An accidental resin release in December 1962 revealed a design deficiency in the condensate demineralizer system. The condensate demineralizer system consists of three half-capacity mixed bed ion exhangers that remove reactor solids carry-over and turbine-condenser system corrosion products from the full condensate flow.[21] Several of the No. 1 condensate demineralizers' outlet diffusers shifted allowing resin to leak through. Failure of one of the outlet basket strainers then permitted a resin release into the feedwater system. Modifications to the diffusers and basket strainers corrected the situation.[22]

Galling of the control rod drive index tubes also caused malfunctions in the drive system. In 1963, metal chips were present in the guide sleeve windows. After several occurrences, the index tubes were replaced with 304 stainless steel index tubes. Eventually, all index tubes were replaced with 304 stainles steel tubes. This resolved the problem of galling. Also in 1963, loose bolts from the fuel-channel-support tubes fell into the control rod drives, causing the control rods to jam. To alleviate the problem of falling bolts, personnel added an additional flow distributor, welded "keepers" on the cap screws, and inserted stabilizer blocks on all unused fuel channels.

On three separate occasions in December 1963, a safety system malfunction involving a scram annunciation was not followed by a scram action. It was impossible to tell which sensor caused the trip. However,

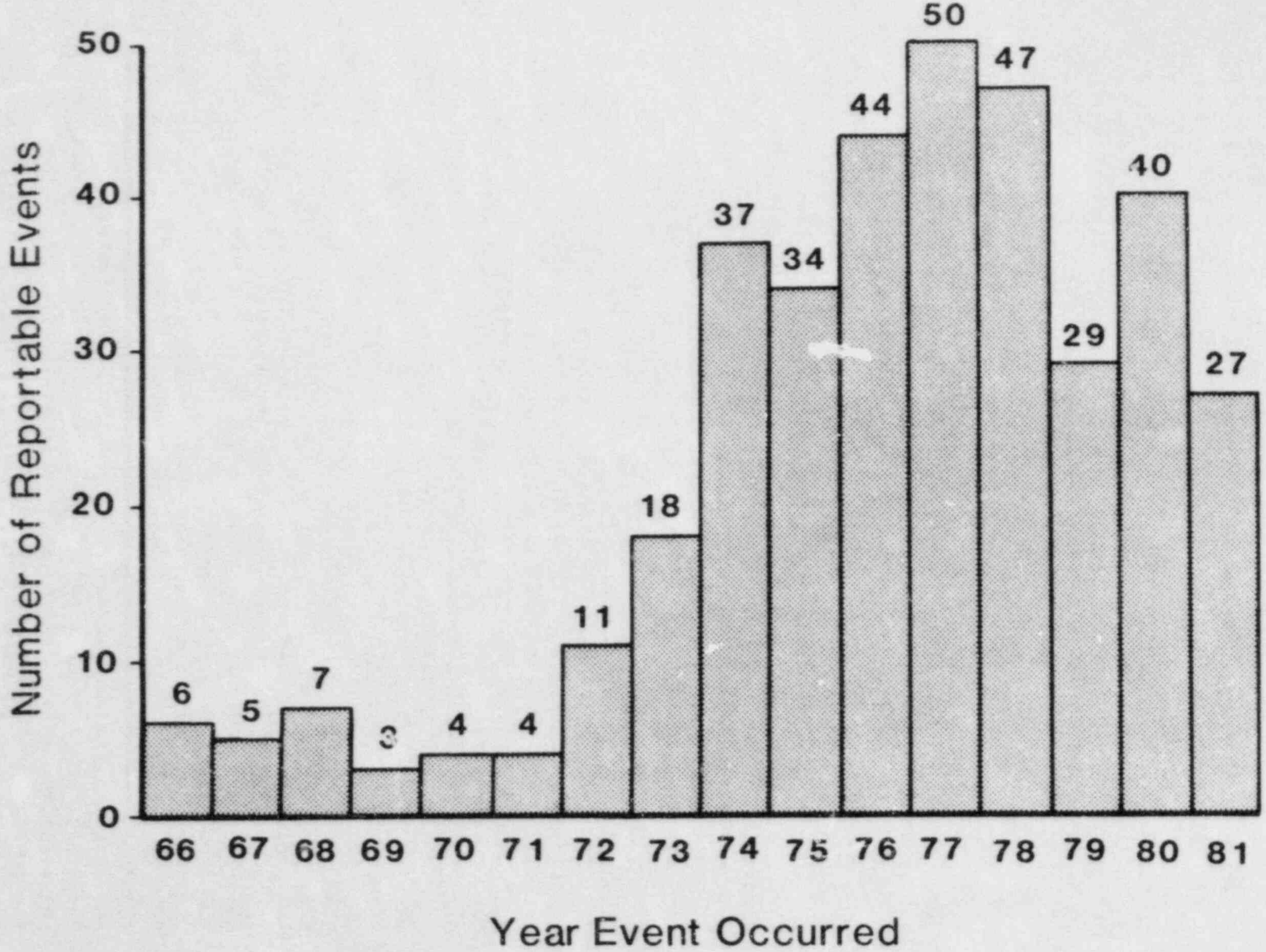

Fig. 4.3. Number of reportable events per year at Big Rock Point.

it was postulated that vibration on a remote panel caused a spurious trip of the steam drum low water level sensors. Tests conducted on the system showed the vibration to be of sufficiently short duration to trip the annunciator relays but not the actual scram relays. Additionally, some "non-fail-safe" failures of certain transistors in the safety system scram logic circuits occurred.[23] These events were not classified as significant due to the limited amount of information available.

Failed fuel cladding became a problem in 1965. The off-gas activity rose consistently until it reached 15,000 μc/s, where it leveled off. This level remained essentially constant until 1966.

1966

The first year reportable events were submitted for Big Rock Point was 1966. The problems involving the control rod drives and the fuel elements continued. Four developmental fuel bundles were the primary contributors to the high off-gas activity. These failures were not expected since the fuel had only reached half of its design life.

A pressure buildup in the scram dump tank caused several control rods to drift out of the core. Water leakage through line seals from the insert header to the withdrawal header was pressurizing the scram dump tank. When the control rod drive pumps were operating, the leakage would pressurize the scram dump tank enough such that the collet piston locking device would open. This allowed the control rods to drift. Installation of a vent line between the scram dump tank and the reactor vessel corrected this design error.

1967

The control rod drive problems and leaking fuel elements were still presenting problems in 1967. On several occasions bolts from the grid bar assembly lodged between the index tube notch and the drive thimble of a control rod drive. This prevented the withdrawal of the control rod. On all occasions the control rod could still be inserted.[24,25] As a result, personnel replaced sixty-eight of the seventy grid bar assembly bolts.

No gross fuel failures occurred this year. In December, power was reduced after the off-gas activity started to increase. Reducing power preserved fuel integrity.

1968

There was only one incident of a stuck control rod in 1968. A bolt lodged in the drive mechanism and prohibited rod movement. This bolt remained from early test work where torque wrenches broke the upper-grid bolts prior to their replacement.

During refueling in February, twenty-nine of thirty-three reload-2 "C" fuel bundles indicated a positive leaking signal after being dry sipped. These bundles were vibratory packed powdered fuel. The off-gas activity again increased in June. During the June refueling, pellet UO_2 rather than powdered UO_2 was loaded into the core. In October, the off-gas activity again increased indicating a clad failure in the new core. The off-gas activity continued to increase into 1969.

1969

Three reportable events occurred during 1970. On two occassions, the diesel generator failed to run. The diesel generator tripped once on overspeed due to an improper overspeed trip set point while the other trip resulted from the diesel generator overheating. Fish lodged in the cooling water pump suction pipe and inhibited cooling water flow to the diesel generator.

On October 20, the reactor was shutdown when an operator noticed the primary coolants' conductivity was increasing. The conductivity increased when resins in the demineralizer decomposed due to high temperatures. High temperature reactor water was drawn through the demineralizer during blowdown of the primary system. The operator was unaware of the rising conductivity since an alarm circuit on a recorder failed. This same failure prevented the cleanup pump from tripping on high temperature and protecting the resin bed.[26]

Power was reduced in January and again in February in order to reduce off-gas activity. Refueling in April revealed nine failed assemblies. The two powdered UO_2 fuel rods that failed were next to the calculated hottest rod in each of the bundles. The other compacted UO_2 powdered fuel rods in equavilent positions did not exhibit the severe crud spalling of the failed powdered rods. However, all of the failed assemblies exhibited of significant crud accumulation and crud spalling. Hot cell examinations on two of the fuel rods showed that the accelerated corrosion on the rod surface was driven by local overheating. Since preliminary investigations revealed accelerated corrosion due to high cladding temperatures, the power was temporarily limited to 165 MWt. The reloading of pellet UO_2 and derating the thermal output of the core solved the problem of leaking fuel elements.

1970

Only four reportable events occurred in 1970. Two events involved the diesel generator. A diode failure caused the diesel generator to fail in developing proper voltage and the diesel generator failed to start due to lack of lube oil supply to the governor. The other two events concerned movement of a water level sensor for greater accessibility and a condenser tube leak.

1971

In 1971, two of the four reportable events involved control rods. The other two events involved the replacement of a section of cleanup system piping due to cracks, and the diesel generator failed to run. The diesel failed due to high temperature in the cooling water system. The centrifugal cooling water pump lost its prime as a result of leakage at the pump shaft packing. The leak depleted the priming water supply during the two weeks between tests. A manual valve for water makeup was left open and steps were taken to provide priming water makeup during a loss of station power.

1972

The number of reportable events for 1972 totaled eleven. Valve failures represented 50% (five out of ten events) of the equipment failures.

1971

There were nine forced shutdowns and two power reductions in 1971. Six resulted from equipment failures, one was due to an operational error, one due to a local storm, and the other was apparently due to sabotage. The apparent sabotage occurred on the first day members of the company-wide union strike (May 12 to September 1).[15] Supervisory personnel, engineers, and technicians operated the plant. The reactor scrammed due to load rejection resulting from a fault in the 138 kV transmission line. The fault resulted when a corner strain pole fell into the adjacent two phases of the power line. The strain pole was cut approximately half way through the thickness of the pole. In addition, the guy line to the pole had been cut.[15] A local storm caused a scram on September 28. Another forced shutdown and the two forced power reductions resulted from defective recirculating pump seals.

The plant continued operation into 1971 at 70% due to premature failure of several "E" fuel bundles. On January 23, the plant shut down to repair turbine condenser leaks. During testing of the containment isolation valves prior to startup, the main steam drain line isolation valve (outside containment) failed to close. The cause was a defective solenoid due to moisture in the instrument air. Personnel replaced the instrument air dryer and four similar valves during the February refueling outage. Also, during the February outage, installation of the redundant core spray system, begun in 1970, was completed and two in-core detector assemblies were replaced.

1972

There were twelve forced shutdowns in 1972. Ten of these resulted from equipment failures, one occurred during testing, and one was due to an operational error. Five of the six forced power reductions resulted from equipment failures. The sixth occurred during maintenance.

A turbine trip occurred on January 25 following a line fault on the offsite 138 kV electric system which was not cleared by the Big Rock Point relaying scheme. As a result, the plant became momentarily isolated from the rest of the 138 kV transmission grid with essentially no load. Concurrently, the redundant 46 kV offsite power supply was also lost due to unusual weather conditions. The diesel generator started and supplied plant loads.

The plant operated in the coastdown mode from January 4 until the refueling shutdown on March 18. During the shutdown, personnel replaced the clean-up systems' heat exchangers the contained Cufenloy tube bundles. The new heat exchangers utilized stainless steel tube bundles in an attempt to eliminate crud deposits on the fuel cladding. This change was made in order to decrease the rate of premature cladding failures.

After several miscellaneous equipment failures caused power reductions or shutdowns, power increased to 83% on July 6 and essentially remained at this level until December 30. On December 30, increased activity levels in the off-gas due to fuel cladding failures required a power reduction to 68%.

The diesel generator experienced two failures during this time period. On May 25, the diesel failed to start when the set points on the lube oil pressure switch were low. On September 14, the diesel failed to achieve rated voltage when the exciter armature shorted. A significant event also occurred in the electric power system when offsite power was lost during a storm. A trip coil in an oil circuit breaker burned out. A more detailed description is provided in Sect. 4.5.2.

1973

The first year for reporting events as abnormal occurrences (AO's) was 1973. The number of reportable events increased to eighteen. Five events were due to setpoint drifts. An administrative error occurred during draining of the fuel pool for relining.[27] A spent fuel rod was found on the pool floor, and draining was halted. The fuel rod had been on the fuel pool floor since the last refueling outage. The rod was stored temporarily in a fuel transfer cask. Procedures for exercising closer control of all spent fuel operations were implemented.

1974

The number of reportable events doubled from 1973 to 1974 (eighteen to thirty-seven). Along with the continuing problems of control rods becoming stuck, on three occasions the control rods were withdrawn too quickly. Other problems occurring during the year included valve failures in the engineered safety features system. The occurrences involved valves that were leaking, tagged out, or not tested as per technical specifications.

An event considered noteworthy occurred during refueling operations on July 15.[28] The supply root valves in the post-incident system were closed and tagged out. The valves had previously been considered part c the fire system. Analysis showed the valves were really common to both systems. Had the post-incident system been required, the operator would have had over two hours to take corrective action before the water level dropped to the reactor flange level. This event was a technical specification violation and operators are now required to check the root valves prior to refueling.

A significant event also occurred during the year. Containment integrity was violated for approximately three months before discovered.[19] See Sect. 4.5.2.6 for further details.

1975

Three of the thirty-four reportable events occurring at Big Rock Point in 1975 were noteworthy and none were significant. The first event occurred in January when a design deficiency was discovered in the reactor level sensors and pressure sensors.[30] The sensors were not qualified to meet the high temperature specifications for LOCA conditions.

The second event concerned several valves in the reactor cleanup system that were rated lower than the design limits required.[31] Five valves were found to be deficient in either their temperature or pressure requirements.

A procedural error was responsible for the third event. On November 13, reactor pressure was reduced for work on the main condenser and personnel inadvertently removed the accumulator to a control rod drive system.[32] The accumulator is required for a scram when the reactor pressure is below 450 psi. The cause was a misunderstanding of an operations memo concerning the shutdown margin. The operations memo was revised to clarify the operating requirements.

1976

The number of reportable events increased to forty-four in 1976. Thirteen of the events were attributable to the reactor depressurization system (RDS), which was installed during the year. The RDS is a part of the ECCS and is used to rapidly reduce the pressure of the primary system during LOCA conditions. The reduction in pressure permits the core spray system to spray water into the reactor vessel.

One event considered noteworthy in 1976 involved the RDS. A review of the RDS test procedures revealed that the monthly on-line tests subjected the system to a violation of the single failure criterion.[33] See Sect. 4.5.1.2.2 for further discussion of this event.

Another event considered noteworthy involved the emergency power system.[34] The diesel generator was supplying 95 kW to busses 1A and 1B following a breaker that tripped due to an overload. The diesel subsequently tripped on high cooling water temperature. The diesel cooling deficiencies were corrected and the diesel was successfully tested with a fire pump load. The plant was in cold shutdown at the time of the event.

Overall, the diesel generator was involved in sixteen of the forty-four reportable events for 1976. Eight of these events were failures of the diesel generator to start within time limits as set forth in the technical specifications. In addition, the diesel generator failed to start on three occasions - twice due to a failed starter and once from failed battery cables.

1977

The RDS accounted for fifteen of the fifty reportable events submitted in 1977. On nine occasions, the specific gravity of an RDS battery was low. Even though the specific gravity was below technical specifications, the battery was still able to perform its function.

The diesel generators were again responsible for a proportion of the reportable events (seven of fifty). As in the previous year, the generators failed to start within the time limit set forth by the technical specifications.

No significant events occurred in 1977, however, two noteworthy events did. On August 5, one of the noteworthy events occurred in the emergency power system.[35] The event involved the diesel generator. However, the generator was not held accountable. The generator was operating properly when automatic and manual transfers of power to the "2B" bus failed. The auxiliary switch, which was installed in 1976 to ensure proper operation of the generator's output breaker, was not wired properly. Normal station power was available during this incident.

The second event occurred on April 21 involving inadequate testing procedures.[36] A review of the ten-year inspection plan revealed several instances where the minimum number of inspections had not been performed to meet the 25% criteria for the first quarter of the ten-year plan. The ten-year plan was revised to correct its deficiencies.

1978

Failures in the RDS again resulted in a substantial number of reportable events in 1978 (nine of forty-seven). Five of the events in the RDS resulted from the failure of one of the four RDS channels being inoperable. The RDS was also involved in a significant event on February 15.[37] During a maintenance activity on the control circuitry of the RDS, the fire pump control switches were placed in the inhibit position. The fire pumps provide initial flow to the ECCS system. If the pumps had been required, the operator would have had to realize the switch was in inhibit and then manually initiate the pumps. Therefore, the system was no longer automatically operable. The fire pump control consoles have been marked with instructions for the use of the inhibit condition. See Sect. 4.5.2 for further details.

On April 7, a significant event occurred involving the reactor protection channels.[38] Two of the reactor protection system channels failed during a loss of offsite power. The failure was attributed to a binding level sensor switch/pointer mechanism on a scale plate inside the cover because of inadequate testing. All four level sensors were repaired and retested prior to plant startup. For further details, see Sect. 4.5.2.

An event worth mentioning occurred in the control rod drive system. A control rod was removed and the reactor mode switch was not placed in the shutdown position as required by technical specifications.[39] This condition existed for several hours until the drive was reinstalled. The incident was reviewed with all repairmen prior to the January 1979 refueling.

1979

The number of reportable events decreased for the second straight year in 1979 (twenty-nine events). The containment isolation system accounted for nine of the reportable events while the reactor coolant system was responsible for eight. Seven of the reportable events were due to valve failures, four due to check valve failures and nine of the reportable events concerned leaks. None of the reportable events involved the RDS.

On June 9, fuel and other internals were removed from the reactor core in order to determine the cause of vibration type noises.[40] One diffuser was completely loose while the other diffuser had several bolts missing. See Sect. 4.5.2.5 for further details.

1980

In 1980, the engineered safety feature (ESF) instrumentation accounted for twelve of the forty reportable events. All of these ESF related events involved set point drift of a level sensor. No events were categorized as significant during 1980.

The RDS appeared to be functioning properly as there were seven reportable events in 1980 and one in 1979, as compared to thirteen, fifteen, and nine in 1976, 1977, and 1978, respectively. All but one of the events involving the RDS in 1980 were reported when the specific gravity of the

RDS batteries fell below technical specifications. The remaining event involved one of the RDS channels being removed from service.

1981

Twenty-seven reportable events occurred during 1981. Five reportable events involved the RDS. The RDS specific battery had a low specific gravity on three occasions. The other two events occurred when a power supply inverter failed, and an operator opened the wrong circuit breaker. Hence, it appears as though the early problems with the RDS were standard "breakin" failures.

The emergency power system was involved in three reportable events. The diesel generator's starting time exceeded the technical specification limit on all three occassions.

No significant events occurred during 1981.

4.5.1.2 Review of reportable events by systems. Table 4.7 presents a compilation of reportable events by system and year. Subsystems having a small number of reportable events were combined into broader system titles where applicable. The code used for the reactor depressurization system (RDS), also known as the automatic depressurization system (ADS), was SF-A. The RDS is a part of the ECCS and was installed in 1975. For the emergency condenser, the system code for reactor core isolation cooling system and controls, CE, was used.

Approximately 76% of the reportable events involved the following systems: reactivity control system (12.8% or 47 events), RDS (13.1% or 48 events), reactor coolant system (12.0% or 44 events) emergency power (12.3% or 45 events), containment isolation (12.8% or 47 events), instrumentation and controls (8.2% or 30 events), and radioactive waste management (5.2% or 19 events). Radioactive waste management, reactor coolant, and instrumentation and controls are general system categories. The other four systems are unique subsystems with a sufficient number of reportable occurrences such that they were considered separately.

4.5.1.2.1 Reactivity control system. The reactivity control system accounted for 12.8% of the reportable events. The control rods and control rod drives were involved with most of the occurrences for this system (thirty-five of forty-seven). Jamming of control rods due to galling of the index tubes or lodging of loose parts in the drive system accounted for thirteen occurrences. On all occasions, the control rods could be inserted. The other major contributor for the reactivity control system concerned the CRD's. The withdrawal time was less than the technical specifications requirement (six occurrences).

Trouble with the control rod drives first occurred during rod performance checks on December 18, 1962. One control rod continued to move downward out of the core after the demand signal was turned off. Examination of this drive indicated that resins in the drive prevented proper operation of the collet fingers. The resins leaked into the primary system when several of the outlet diffusers shifted. Failure of an outlet strainer resulted in a resin release into the feedwater system. On February 17, 1963, another rod drive would not relatch. Inspection of the drive revealed nothing apparently wrong. However, the drive was rebuilt

Table 4.7. Summary of systems involved in reportable events

System	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Reactor	2	4	4			2	3	1	10	9	3	6	7	3	2	1	58
Reactor coolant	3		2	1		1	1	2	1	4	1	7	7	8	6		44
Engineered safety features							2	5	8	9	19	25	12	13	15	12	120
Instrumentation and controls					1			2	5	1	2	1	5	2	12		30
Electric power	1		1	2	2	1	3	1	5	4	18	8	6	2	5	4	63
Fuel handling								1	1	2			2				6
Other auxiliary systems										1		1	4			1	7
Steam and power	1				1			2		2	1		3	1			1'
Radiation protection									1			1	1			1	4
Radioactive waste management		1					2	3	4	2			2			5	19
No system applicable								1	2	1		2					6
Auxiliary water																2	2
TOTAL	7	5	7	3	4	4	11	18	37	35	44	51	49	29	40	27	371

since it was in the core position where the resin was deposited earlier.[41] After the reactor was cleaned, no drive failures due to resin deposits occurred.

One of the major concerns for the control rod drive system appeared several years after the resin deposits were cleaned up. On June 22, 1966, several rods again drifted out of the core. The scram dump tank was being pressurized by leakage of water through line seals from the insert header to the withdrawal header. When the control rod drive pumps were operating, the leakage pressurized the scram dump tank. This pressure buildup was enough to open the collet piston locking device, thereby allowing the rods to drift. Therefore, a vent line was installed between the scram dump tank and the reactor vessel. No occurrence of this type has occurred since this modification.

4.5.1.2.2 Reactor depressurization system. The reactor depressurization system accounted for 13.1% of the reportable events. This system was incorporated into Big Rock Point's ECCS in 1976. A large majority of the reportable events were due to the specific gravity of the RDS batteries (28 of 48) being below the technical specifications limit. The RDS instrument channels were involved in eleven of the reportable events. Several events occurred as a result of a new system being installed. The first event occurred on September 7, 1976. Procedures for the fire pump actuation tests had not been developed. Testing of the fire pumps had been done during the initial checkout of the system, but the method used was not feasible during operation. After developing new procedures, testing of the RDS was successfully completed. The next two reportable events occurred on December 9, 1976. A review of surveillance test procedures revealed that the monthly online test procedures subjected the system to a violation of the single failure design criteria for inadvertent operation.[33] The procedure development was inadequate due to insufficient knowledge of the actuation system. Subsequent review indicated that weekly verification of the continuous automatic test circuitry and additional testing during refueling operations would provide adequate testing. The last event of interest occurred on February 15, 1978.[25] During maintenance activity on the control circuitry, the fire pump control switches were in the inhibit position. Therefore, the system was no longer automatically operable. The fire pump control switches on the RDS console have been marked with specific instructions for the use of the inhibit position.

4.5.1.2.3 Reactor coolant system and connected systems. The eleven reactor coolant system (RCS) and connected systems accounted for 12.0% of the reportable events. The emergency condenser and reactor core coolant cleanup systems accounted for 50% (twenty-two of forty-four). Valves, piping and welds were the most common equipment failures (twenty-six events or 58.7%). The most common occurrence involved a leak or a crack which had not propagated through-wall (fourteen events or 31.8%). The next major contributor was weld related failures (six events or 13.6%).

Another important event involved the RCS and connected systems, specifically the coolant recirculation and controls system. During inspection for leakage in the control rod drive room on April 20, 1979, noise was heard in the primary system with the recirculation pump in service. On June 9, 1979, it was discovered that a diffuser dislodged from the No. 1 recirculation inlet, while on June 13 a loose diffuser on the No. 2 recirculation inlet was found.[40] Based on geometry factors and flow data, flow blockage did not occur. See Sect. 4.5.2.5 for further details.

4.5.1.2.4 Emergency power. The emergency power system accounted for 48 of the reportable events (Table 4.8). Forty-seven of these involved the diesel generator. Overall, there were twenty-one failures of Big Rock Point's emergency power system. Failure of the diesel generator to start or run accounted for eleven and nine of the failures respectively. No dominant cause was identified for the failures to start. High cooling water temperature caused six of the diesel generator trips.

One of the trips due to a high cooling water temperature occurred while the diesel generator was supplying a load to buses 1A and 2B following an overload trip of breaker 52-2A on May 16, 1976. The cooling pump shaft was scored and the inlet screen was partially plugged. The discharge canal was flushed after removing stop logs to clear debris from the discharge canal bay and the coding pump shaft was replaced.[42]

Sixteen of the reportable events involved an unacceptable response time of the emergency diesel generator. The term "unacceptable response time" represents failure of the diesel generator to start within the time limits required by the technical specifications. The startup time has varied throughout the plant history. Around October 1976, the diesels' response time was changed from 15 sec to 12 sec. In April 1977, the response time was increased to 13.9 sec. On February 25, 1980, Consumers Power Company requested a diesel generator response time of 31 sec. Consequently, the number of "failures" greatly depends on the startup time criteria.

All but one of the emergency power system failures involved the failure of the diesel generator. Additionally, none of the failures occurred during a loss of offsite power. The only emergency power system failure involving a diesel generator occurred during routine testing of the emergency diesel generator. The 2A-2B breaker was racked out of position and normal power sources were available for bus 2B (Fig. 4.4). During a loss of offsite power, bus 2B is automatically connected to the emergency diesel generator. The 2B bus is the only bus automatically loaded on to the emergency diesel generator. Current plant system operating procedures require the operator to strip most loads from buses 1A and 2A before connecting these buses to the EDG.[43]

The technical specifications require monthly testing of the EDG on the 2B bus with a minimum load of at least the electric fire pump. This test consists of interrupting power to the 2B bus causing the EDG to automatically start and energize the bus. During this test on August 5, 1977, the automatic transfer of power to the 2B bus failed to operate.[35] A manual transfer of power also failed to close the generator output breaker. The normal power source was transferred to the 2B bus. The auxiliary switch designed to maintain the generator output breaker operable with the 2A-2B breaker racked out was not wired properly by contract personnel. The circuit continuity testing associated with the design change (in 1976), done in lieu of a complete functional test, was inadequate.[44]

Table 4.8. Diesel generator failures at Big Rock Point

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	FAILURE MODE	DESCRIPTION
68-6	-	113068	failed to start	Emergency diesel generator (EDG) linkage pin designed wrong.
69-2	-	022069	failed to run	EDG overheated due to fish lodged in cooling water pump suction pipe.
69-3	-	060069	failed to run	EDG tripped on overspeed due to improper overspeed trip point setting.
70-2	57230	080670	under voltage	Diode failure caused EDG to fail to develop proper voltage.
70-4	-	100170	failed to start	EDG failed to start due to lack of lube oil supply to governor.
71-4	65547	071571	failed to run	EDG failed to run due to high cooling water temperature.
72-4	73801	052572	failed to start	EDG failed to start due to low pressure set point.
79-2	-	091472	under voltage	Shorted exciter armature caused EDG to fail to develop proper voltage.
A07313	80732	041973	failed to run	EDG shutdown due to high coolant temperature.
A07402	89319	030774	failed to start	EDG failed to start due to failed relay contacts.
A07407	90577	041174	failed to start	EDG starting motor mechanism failed.
A07415	92611	053174	failed to run	EDG transfer pump failed due to key on pump shaft corroding.
A07425	97742	111474	failed to start	EDG did not start due to corroded battery terminals.
A07509	102299	041075	failed to start	EDG failed to start, cause unknown.
B07604	113200	032476	failed to run	EDG tripped due to high cooling water temperature.
B07608	115042	051676	failed to run	EDG tripped while supplying load due to high cooling water temperature.
B07609	115066	051676		EDG breaker interlock did not function automatically due to wrong fuse.
B07611	-	060576		EDG control circuit completed without review, wrong fuse size used.
R07618	116786	072276	starting time too long	Starting time of EDG exceeded limit by 10 sec, cause unknown.
R07621	117676	080576	starting time too long	EDG failed to start within time limit, cause unknown.
B07623	117677	080576		EDG returned to operable status without retesting.
B07622	-	08[illegible]276	failed to start	EDG failed to start due to battery cable faults.
B07625	119154	090276	starting time too long	EDG failed starting test by 20 sec due to fuel system problems.
B07631	119751	102876	starting time too long	EDG failed to start within time limit, cause unknown.

Table 4.8. (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	FAILURE MODE	DESCRIPTION
RO7632	120270	110476	starting time too long	EDG failed starting test by 2.2 sec due to fuel governor problems.
RO7636	120680	111876	failed to start	EDG failed to start due to failed starter.
RO7638	120677	120276	starting time too long	EDG failed starting test by 5 sec, cause unknown.
RO7644	121052	122076	starting time too long	EDG failed starting test by 4 sec. Fuel governor lube oil supply problems.
RO7645	121523	122776	starting time too long	EDG failed starting test by 3 sec. Fuel governor lube oil supply modified.
RO7646	121524	122876	failed to start	EDG failed to start; the starter failed.
RO7701	121525	010377	failed to start	EDG failed to auto-start. Probable cause was lube oil supply system.
RO7705	122186	010777		EDG out of service 8 hrs to modify fuel oil lube governor.
RO7710	124901	032477	starting time too long	EDG failed starting test by 0.8 sec, cause unknown.
RO7718	125549	051877	starting time too long	EDG failed starting test by 12 sec, could be due to ambient temperature.
RO7719	125550	052677	starting time too long	EDG failed starting test by 2.6 sec, fuel control valve was modified.
RO7727	128946	080577		Transfer of EDG power to 2B bus failed.
RO7741	130997	102077	starting time too long	EDG failed starting test by 7.9 sec, cause unknown.
RO7807	136470	020978	failed to run	EDG triped after 25 min due to high cooling water temperature.
RO7804	136475	022078	starting time too long	EDG failed starting test by 14.6 sec,cause unknown.
LER7908	148201	022279	starting time too long	EDG failed starting test by 1.9 sec due to air in fuel line.
LER7914	149434	031279	under voltage	EDG output voltage zero, cause unknown.
LER8036	161980	111880	under voltage	EDG failed to reach rated voltage due to two failed diodes.
LER8037	161982	111880	failed to run	EDG failed to run due to overheated bearing seal.
LER8044	170072	121080	over voltage	EDG voltage regulator circuit failed due to aging or vibration.
LER8047	162577	121780	under voltage	EDG output voltage was too low due to broken pins in a relay socket.
LER8105	165396	032181	starting time too long	EDG failed starting test by 7.9 sec, cause unknown.
LER8107	166068	041481	starting time too long	EDG failed starting test by 0.7 sec, cause unknown.
LER8108	166064	042081	starting time too long	EDG failed starting test by 29 sec due to failed fuel injectors.

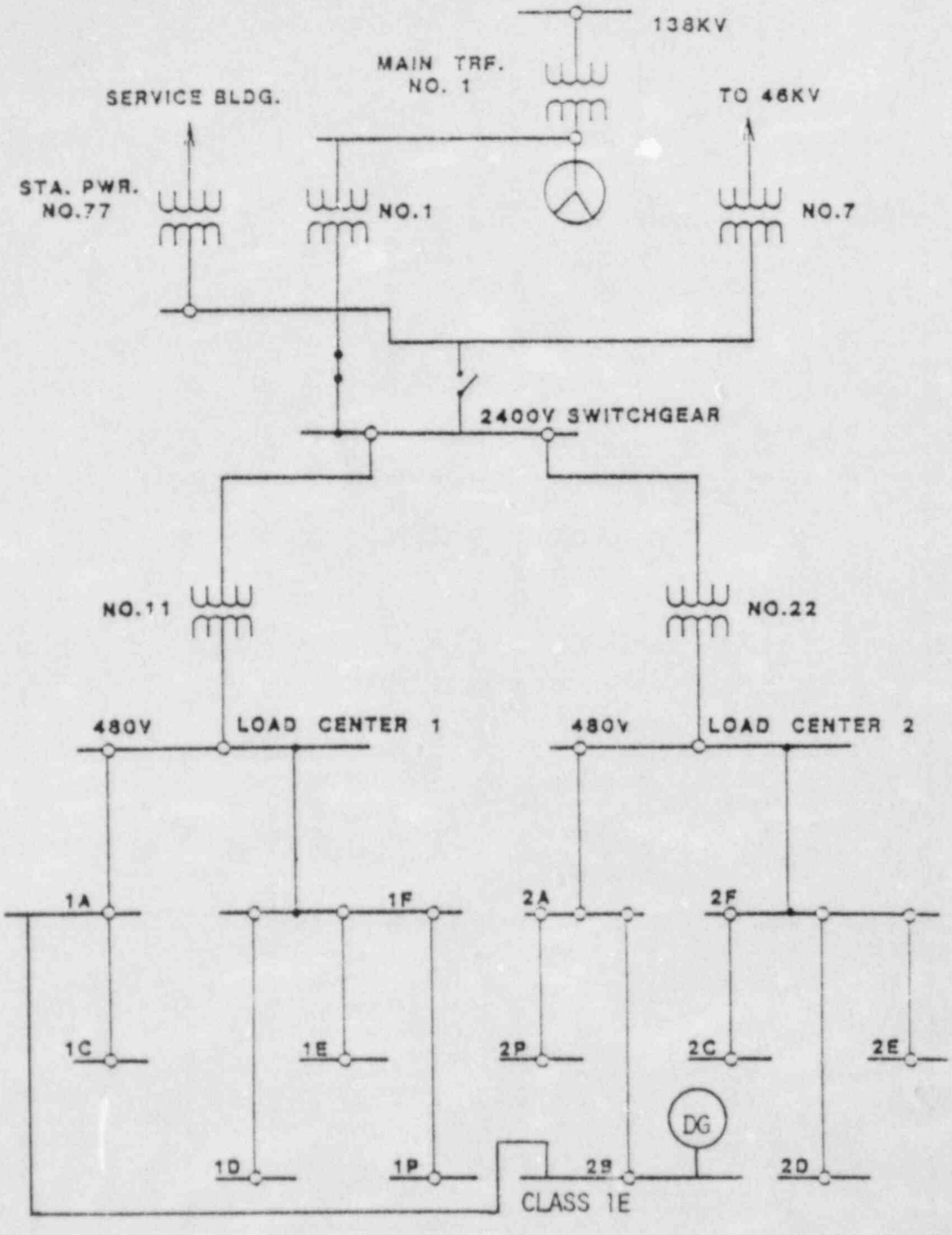

Fig. 4.4. Single line diagram of the Big Rock Point Power station.

In May 1976, Big Rock Point was granted a lifetime exemption from the single failure requirement as applied to a LOCA caused by a break in a core spray line and a concurrent single failure in the remaining core spray system. In addition, Big Rock Point was granted a lifetime exemption from the requirement that the ECCS short-term and long-term cooling functions be invulnerable to a single failure which disables onsite power assuming off-site power is unavailable. This was allowed in view of the high availability of offsite power (3 LOOP's identified), and the improved reliability of the onsite diesel and availability of a backup diesel for long term cooling.[43]

4.5.1.2.5 Containment isolation. The containment isolation system accounted for 47 (12.8%) of the reportable events. Valve failures contributed to 21 of the occurrences for this system, while 15 of these failures resulted in leaks. Of all the system failures, 22 were inherent failures and 9 resulted from administrative errors. The only significant event involving this system also resulted from an administrative error. Containment integrity was jeopardized for approximately three months when a test fixture was left installed on an emergency escape lock. See Sect. 4.5.2.6 for further details.

4.5.1.2.6 Instrumentation and controls. Instrumentation and controls accounted for thirty (8.2%) of the reportable events. The majority of these events involved engineered safety feature instrumentation (nineteen events). Only two of the events involved equipment failures: an equalizing valve was left open and nonqualified cables and connectors were replaced. All remaining failures were attributable to instrument errors. Of these, failure of level sensors dominated. Most of the events involving level sensors were due to set point drift. Overall, setpoint drift accounted for fifteen of the reportable events.

One event involving this system was categorized as significant. On April 7, 1978, two reactor protection channels failed to operate during a loss of offsite power (LOOP).[38] The level sensors switch/pointer mechanism was binding on a scale plate inside the cover. After the new covers were installed, they were not adequately tested. All four sensors were repaired and retested prior to plant startup. Further details of this event are discussed in Sect. 4.5.2.

Two noteworthy events also occurred in this system. The first event occurred on January 16, 1975 when a design review of the existing core spray switches revealed that eight reactor pressure switches and eight reactor water level switches did not meet the high temperature specifications for the design basis LOCA.[30] Due to these deficiencies, it was not known whether the core spray or backup core spray systems would automatically operate under all postulated accident conditions. However, manual actuation of the core spray system was available.

Another noteworthy event occurred on September 11, 1978.[39] A control rod was removed and the reactor mode switch was not placed in the shutdown position required by technical specifications. This condition existed for several hours until the drive was reinstalled.

4.5.1.2.7 Radioactive waste management. Radioactive waste management accounted for nineteen (5.2%) of the reportable events. A majority of the events occurred in the gaseous radioactive waste management system (eight events). Four of these events involved the off-gas isolation valve leaking (once), being left open (once), or failing the seat (twice). Four incidents involving the radioactive waste management system resulted in personnel exposures or radioactive releases. These events are discussed in Sect. 4.5.1.4. None of the reportable events for this system threatened plant safety.

4.5.1.3 Causes of reportable events. Each reportable event was categorized by the cause codes listed in Table 1.4. The number of reports attributed to each cause is found by year in Table 4.9 and is graphically depicted in Fig. 4.5.

These cause codes can be divided into two groups, non-human causes and human causes. The non-human category includes inherent failure, lightning, and weather. The human failure category includes all the remaining codes. Human failure can be further subdivided into two groups: out-of-plant personnel error and in-plant personnel error. Out-of-plant personnel errors involve administrative, design and fabrication errors which generally concern the reactor or component vendor, the A/E, or the utility management. In-plant personnel errors concern hands on human involvement such as installation, maintenance or operator errors and in most cases pertains to the plant operating staff itself.

The number of reports were evenly divided between non-human and human causes with each group contributing 199 and 171 reports respectively. Out-of-plant human errors contributed 107 reports while in-plant human error resulted in only sixty-four reports. Thus about 2/3 of the human errors were caused by people removed from the plant.

4.5.1.4 Events of environmental importance. A summary of radioactivity releases from Big Rock Point is shown in Table 4.10. The table gives the airborne and liquid releases and the solid waste shipped for the years 1966 through 1979.

Nine events at Big Rock Point involved or could have involved radioactivity releases and personnel exposure. These events are listed in Table 4.11. Eight involved actual releases beyond the plant boundary or possible personnel exposure. The ninth involved a high iodine level in the demineralized water storage tank.

Five of the radiation releases or personnel exposures were caused by human errors (four administrative, one operator). The most significant environmental release was classified as an administrative error. On August 21, 1978, personnel pinpointed the cause of radiation in the demineralized water.[45] A failed check valve allowed water from the fuel pool system to backflow into the demineralized water system. A survey of all employees revealed that 25 gal of unmonitored demineralized water was removed from the plant. Fifteen gal were retrieved and it was determined that no human consumption occurred. The 25 gal contained an activity of 0.074 Ci.

Table 4.9. Cause of reportable events at Big Rock Point by year

Cause		1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Administrative error	(A)			1					4	8	13	7	7	2	2	4		48
Design error	(B)	2		2		1		3	2	5	7	6	5	6	6		3	48
Fabrication error	(C)	1						2		3	2	1				2		11
Inherent error	(D)	2	5	4	2	3	4	4	9	11	7	21	30	28	17	29	20	196
Installation error	(E)	1								3	2		5	2	2	1		16
Lightning	(F)	1																1
Maintenance error	(G)		1		1				3	4	3	8		3	1	5	1	30
Operator error	(H)							1		3	2	2	2	5			3	18
Weather	(I)	1						1										2
Unknown or no code													2	2	1	1		6
TOTAL		8	6	7	3	4	4	11	18	37	36	45	51	48	29	42	27	376

Table 4.10. Summary of radioactivity released from Big Rock Point

Effluent	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Airborne:															
Total noble gas	6.8E+05[c]	ND	ND	ND	2.80E+05	2.84E+05	2.58E+05	2.30E+05	1.88E+05	5.06E+04	1.52E+04	1.34E+04	1.89E+04	6.67E+03	2.02E+04
Total I-131		ND	ND	ND	IH	IH	IH	4.60E+00	9.01E-02	2.19E-02	IH	1.40E-03	2.87E-03	2.99E-04	1.07E-03
Total halogens (including I-131)		ND	ND	ND	1.3E-01[a]	6.1E-01[a]	1.5E-01[a]	4.70E+00	3.55E-01	2.67E-01	[illegible].0E-02[b]	2.01E-01	1.46E-01	7.86E-03	2.37E-02
Total particulates ($T_{1/2}$ > 8d)		ND	ND	ND	IH	IH	IH	3.70E-01	9.20E-02	9.80E-02	IH	8.62E-03	6.04E-03	1.60E-03	1.40E-02
Total tritium		ND	ND	ND	ND	ND	ND	7.71E+01	3.87E+01	7.39E+00	2.41E+00	1.08E+01	8.32E+00	3.15E+00	1.26E+01
Liquid:															
Total mixed fission and activation products	6.8[d]	ND	ND	ND	4.70E+00	3.50E+00	1.10E+00	2.70E+00	1.07E+00	2.62E+00	7.70E-01	3.92E-01	2.74E-01	9.03E-01	7.81E-01
Total tritium		ND	ND	ND	5.40E+01	1.03E+01	1.04E+01	1.97E+01	5.07E+01	5.73E+00	2.41E+00	8.83E+00	4.05E+00	5.45E+00	6.18E+00
Dissolved noble gases		ND	ND	ND	ND	ND	ND	1.70E-02	0.00E+00	7.24E-03	ND	0.00E+00	0.00E+00	5.45E-04	0.00E+00
Solid:	f122	ND	ND	ND	ND	ND	1.05E+00	1.20E+04	1.99E+02	1.57E+05	3.69E+00	9.68E+02	2.56E+01	2.77E+02	3.10E+01

[a]Halogens and particulates including I-131

[b]Reported as I-131 and particulates

[c]Total airborne

[d]Total liquid

IH = Included in Halogens

ND = No data

Table 4.11 Events of Environmental Significance

NSIC Accession Number	Number	Event Date	Cause	Comment
19247	67-3	09/12/67	D	A worker was exposed while fixing a leaky diaphram.
31307	68-3	06/24/68	A	Personnel were overexposed while repairing a recirculation pump.
60903	70-3	11/13/70	D	Condenser tube leaked and noncondensible gas drawn into cooling water - 1.04 Ci released to canal.
77861	72-10	12/16/72	D	Leaks into the emergency condenser caused a radiation release.
74354		05/00/73	A	Radiation levels at the fence were high.
93506	UE7502	01/22/75	A	Radioactive waste water was poured into a floor drain.
130883	R07744	10/31/77	H	Reactor coolant backed up into the plant heating system.
140350	R07832	08/19/78	A	A failed check valve allowed water from the fuel pool system to backflow into the demineralized water system. 25 gal of unmonitored water removed from the plant.
177025	LER 81-027	12/30/81	D	High iodine level in the demineralized water storage tank.

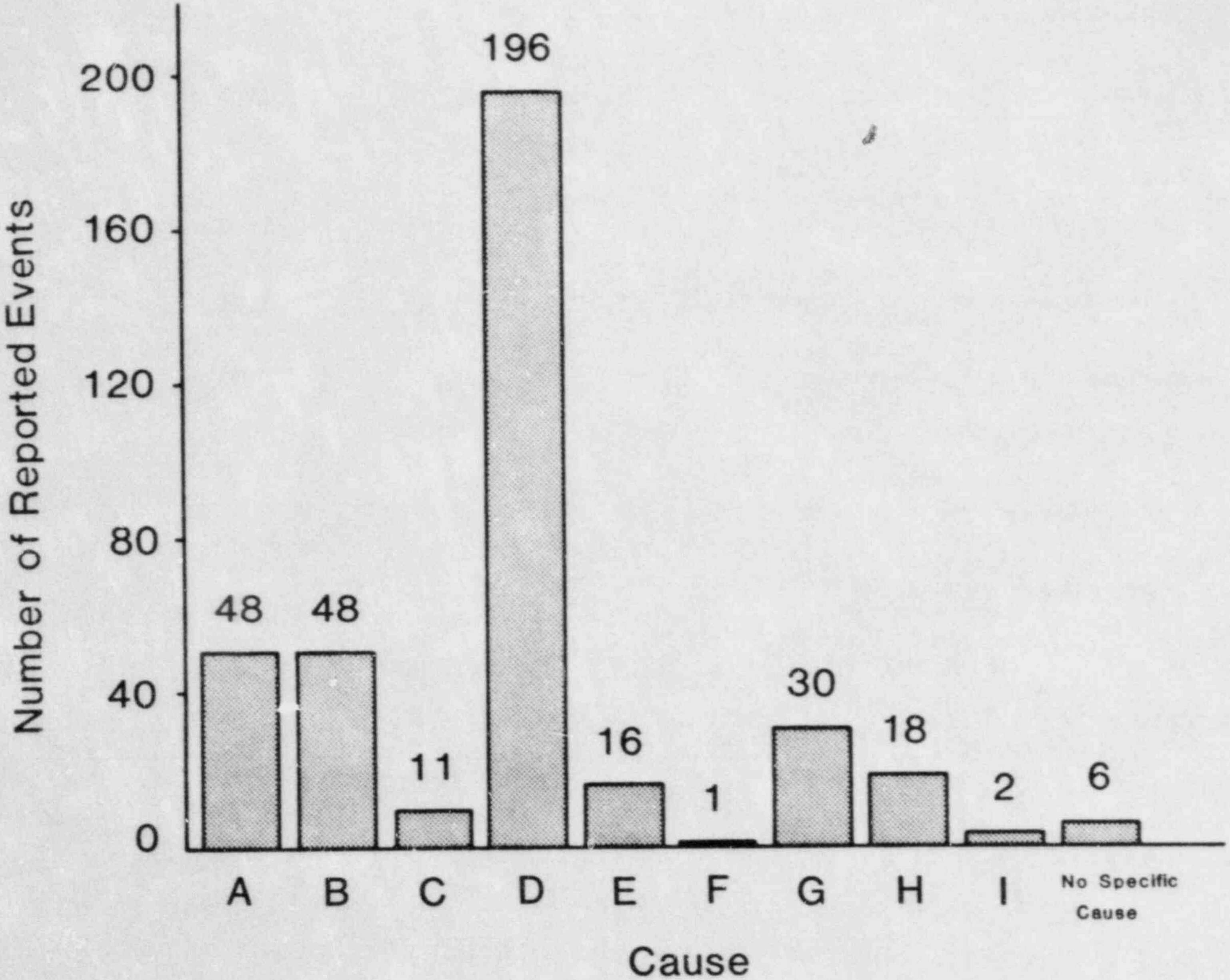

Fig. 4.5. Causes of reportable events at Big Rock Point.

4.5.2 Review of significant events.

A tabulation of each type of significant event appears in Table 4.12. Definitions of the event codes are in Table 3.3. Each reportable event considered significant is identified in Table 4.13. The events which degraded a safety function or initiated a D3E are: losses of offsite power (3), failure of the emergency core cooling system (ECCS) to auto-initiate (1), failure of reactor vessel internals (1), and containment integrity violated (1).

4.5.2.1 Loss of offsite power with radioactivity release. On August 8, 1966, a violent storm caused the 138 kV breaker to open. The turbine bypass valve opened too slowly, thus the reactor scrammed on high pressure before the turbine could be run back to supply house loads. The turbine continued to supply station loads until it was manually tripped four minutes later. When station power was lost (i.e., the turbine tripped), the bypass valve opened before the d.c. operated isolation valve closed. The turbine rupture diaphram then ruptured. Steam discharged into the turbine building for approximately a minute (until the MSIV closed). The steam release raised the airborne activity in the turbine and office area to the point where all personnel except the control room operators were evacuated to the screen house. Station power was restored shortly after the diaphragm ruptured. Airborne activity in the turbine room was returned to normal four hours later by the turbine building ventilation system. No indications of contamination could be found outside the plant buildings.[46] Prior to March of 1968 only one offsite line existed. Thus, every load rejection represented a complete loss of offsite power.

4.5.2.2 Loss of offsite power followed by several component failures. On January 25, 1972, a severe winter storm caused the transmission lines to became ice laden.[47] High winds on the following day caused several momentary line faults when the conductors moved relative to one another. Protective circuits operated successfully on twelve occasions to clear these faults. However, on the thirteenth fault, a trip coil burned out in an oil circuit breaker and the circuit breaker failed to open. Protective relays in the substation operated to clear the fault. In doing so, the generator was momentarily isolated from the load and it tripped on overspeed. The reactor subsequently tripped on high flux. Since the fault occurred on the distribution side of the substation, a load rejection signal was not transmitted to the circuit breaker protecting the generator. Thus, a turbine runback was never initiated. The 138 kV line circuit breaker was manually opened because the line became intermittenly de-energized over a twenty minute period. This resulted in an undervoltage signal and an automatic transfer to the 46 kV alternate source. During the transfer however, a stuck contact on an instantaneous overcurrent relay in the 46 kV bus protection relay scheme, coupled with the operation of the undervoltage bus fault detector relay, caused the circuit breaker serving the 46 kV line to trip. This de-energized the 46 kV line back to Big Rock Point. Normally, the bus fault detector would have reopened had the fault cleared within a few cycles, however, the fault lasted sixty-nine cycles. Thus both offsite power sources were lost. The diesel generator started and provided power to essential loads. Within twenty minutes, full potential was provided to the 138 kV line. When attempts were

Table 4.12. Number of significant events at Big Rock Point

Significance category	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	Total number assigned
S_3 Two or more failures due to common cause													1			1
S_4 Component failures that could have easily escaped detection														1		1
S_6 Event that is not enveloped by the plant design bases									1							1
S_7 An event which could have been a greater threat	1						1									2
S_8 Fundamental misunderstanding of plant performance or safety requirements													1			1
TOTAL	1						1		1				2	1		6

Table 4.13. Tabulation of reports categorized as significant at Big Rock Point

Report Number	Event Date	Significance	Event Description	Section
66-3	080866	S7	Loss of offsite power and rupture of condenser rupture diaphragm (14893).	4.5.2.1
72-1	012572	S7	Off-site power lost during storm and switchgear malfunctioned.	4.5.2.2
A07423	091774	S6	Test fixture on containment emergency escape lock left installed on lock.	4.5.2.6
R07808	021578	S8	Both fire pumps unavailable with ADS out for maintenance.	4.5.2.4
R07818	040778	S2	Failure of two RPS channels during LOOP.	4.5.2.3
LER7920	060979	S4	Recirculation diffusers break off.	4.5.2.5

made to reclose the breaker, the audio tone relay equipment generated a false trip signal causing the breaker to immediately retrip. Once the audio tone trip was defeated, the 138 kV line was restored. The tone controls were reconnected and the plant loads were transferred to the 138 kV source.

The two emergency condenser valves, MO-7063 and MO-7053, automatically opened during the transient in order to control reactor pressure. Approximately two and one half hours later, an attempt was made to close the valves to conserve reactor pressure. Valve MO-7063 failed to operate. An investigation revealed an improperly set torque switch caused the valve's motor operator to burn out.

A design error in the spent fuel pool piping configuration and valve alignment was discovered on January 26. At the time of the outage, the fuel pool was valved for recycle through the radwaste system. When normal power was lost, the spent fuel pit, the radwaste and treated waste pumps ceased to operate and the spent fuel pit to radwaste isolation valves automatically closed. Due to the valving and piping arrangement, an 11-1/2 ft head was established between the fuel pool and treated receiver tanks.

Due to the available head, reopening of the isolation valves created a siphoning action from the fuel pool to the clean waste receiver tanks. The situation was discovered when the operator realized the radiation level in the fuel pool area was gradually increasing. Corrective actions taken to eliminate the hydraulic head consisted of closing a radwaste valve in the fuel pit pump room. The fuel pool level was restored via the waste holding tanks.

4.5.2.3. Two reactor protection channels fail during a partial loss of off-site power. An event in which a common mode failure was involved occurred on April 7, 1978.[38] The loss of the 138 kV transmission line resulted in a load rejection and the reactor scrammed on low condenser vacuum. What caused the loss of this line was not discussed. During the transient however, one of two low drum level scram sensors in both reactor protection channels became stuck at the +5 in drum level. An investigation revealed that the switch/pointer mechanism was binding on a scale plate inside the instrument's cover. A new cover and scale plate had been installed a month and a half earlier but the problem was not detected during the test. All four sensors were repaired and tested prior to plant startup. This event represented a degradation of the reactor protection system.

4.5.2.4. Failure of the ECCS to auto-initiate or auto-transfer. On February 15, 1978, both fire pumps were unavailable in the automatic mode due to a maintenance error on the reactor depressurization system control circuitry.[37] The fire pump control switches were inadvertently placed in the inhibit mode with both pumps shutdown. The fire pumps provide initial flow to the ECCS system. Should the pumps have been required, the operator would have had to realize the switch was in inhibit and then manually initiate the pumps. The fire pump control switches on the RDS panel have been marked with specific instructions for use of the inhibit position.

4.5.2.5 Failure of a reactor vessel internal. While shutdown to inspect the control rod drive room for leakage associated with control rod drive housing F-2, a vibration type noise was noticed in the primary system associated with operation of reactor recirculation pump No. 1.[40] In associated activities, on June 9, 1979, fuel and other internals were removed from the reactor for accessibility to the lower areas of the vessel. The main portion of the diffuser over the 20 in. diameter inlet to the No. 1 recirculation pump was found completely loose and lodged in the cavity between the vessel wall, the core support plate and a large flow baffle. A small portion of the diffuser, including one of the two upper attachment ears, was found below the core support plate.

Inspection of the diffuser over the No. 2 recirculation pump 20 in. diameter inlet revealed that the single lower attachment was loose. This would allow that diffuser to move on its upper attachments in a hinge fashion and make contact with the large baffle. This probably was the source of the vibration type noise first noticed on April 20, 1979.

Based on geometry factors and flow data, it was believed that flow blockage did not occur. However, this does represent a possible initiating event of flow blockage to the reactor core.

A total of four failed bolts were missing: three from the No. 1 diffuser and one from the No. 2 diffuser. One well-worn bolt piece was retrieved during the outage. Other pieces were believed to have been retrieved in prior years dating back to 1974.

4.5.2.6 Containment integrity violated. On September 17, 1974, personnel discovered that an emergency lock test fixture had been left installed since June 21.[23] The test fixture was used to pressurize the containment emergency escape lock. The lock with the vent valve was left in the open position. The inner door of the lock was left open for personnel safety requirements. Leak testing procedures did not specify the removal of the test fixture. The inner door was immediately closed to reestablish containment integrity and the test fixture was removed.

4.5.3 Trends and safety implications of reportable events

As an additional step in the overall evaluation process, the events at Big Rock Point were examined to find discernible recurring events that indicate potential safety problems. The three types of recurring events found were:

1. emergency condenser failures,
2. control rod drive problems, and
3. failed fuel elements.

4.5.3.1 Emergency condenser. Failures involving the emergency condenser were reported in eleven LERs. Two of these failures were failures that rendered one of the condensing loops inoperable. Both events (A07303, LER7828) resulted from valve failures. The emergency condenser system utilizes two condensing loops to provide a heat sink during a number of transients. The emergency condenser is designed for a maximum capacity of 4% of 240 Mwt. A single tube bundle is sufficient to remove 2% of 240 Mwt following shutdown. Additionally, the water storage in the emergency condenser is sufficient for four hours operation without makeup.[48]

4.5.3.2 Control rod drive problems. The control rods and the CRDs experienced difficulty in the earlier years at Big Rock Point. Reoccurring problems involved: the control rods drifting out of the core, galling of the control rod index tubes, jamming of the rods, and the withdrawal times less than technical specifications limit.

Trouble with the control rod drives was noted during the rod performance checks on December 18, 1962. One control rod continued to move downward, out of the core after the demand signal was turned off. Examination of this drive indicated that resins in the drive prevented proper operation of the collet fingers. The resins leaked into the primary system when several of the outlet diffusers shifted. Failure of one of the outlet strainers then permitted resins to enter the feedwater system. On February 17, 1963, another control rod drive would not relatch. Inspection of the drive revealed nothing apparently wrong. However, the drive was rebuilt anyway since it was in the core position where the resin was deposited earlier. After the reactor was cleaned, no drive failures due to resin deposits occurred.

On June 22, 1966, after the resin deposits were cleaned up, several rods again drifted out of the core. It was determined that the scram dump tank was being pressurized by leakage of water through line seals from the insert header to the withdrawal header. When the control rod drive pumps were operating, the leakage pressurized the scram dump tank. This pressure buildup was enough to open the collet piston locking device, thereby allowing the rods to drift. Therefore, a vent line was installed between the scram dump tank and the reactor vessel. No occurrence of this type has occurred again since this modification.

The first incident of index tube galling occurred during a scram test on February 20, 1963. Flow measurements indicated high leakage through the drive system. Some resin was still present, but a large number of metal chips were also present in the guide sleeve windows. After a number of such occurrences, nitrided 304 SS index tubes were installed in place of several 17-4 PH SS index tubes. On October 31, 1965, four drive systems stuck due to metal particles. None of the previously modified drives were among the four. Therefore, all remaining drives were modified and no galling of index tubes has been reported since this modifications.

Jamming of control rods due to galling of the index tubes or lodging of loose parts in the drive system accounted for thirteen of the occurrences. The first occurrence of a control rod jamming occurred on December 18, 1962. Several control rod drives jammed when loose bolts lodged on top of the core support plate. The bolts were the same type as those used to bolt together the fuel channels and their support tubes. As a result, all Zircaloy support-tube-and-channel assemblies were modified by staking the cap screws. A drive in the same core position jammed on May 26, 1963. Additional modifications included an additional flow distributor along with welding of "keepers" on the cap screws.

Loose bolts continued to cause the control rods to stick. On December 25, 1967, several drives stuck when bolts from the grid bar assembly became lodged. As a result, sixty-eight of the seventy grid bar assembly bolts were replaced. On April 6, 1968, another loose bolt in the control rod drive mechanism caused a control rod to jam. The bolt remained from the previous year when torque wrenches broke off several of the upper-grid bar assembly bolts prior to replacement.

The control rods became jammed on several other occasions, however, their occurrences were infrequent.

The last major contributor to the reportable events in the control rod drive system involved the withdrawal time being less than the technical specifications limit. The first three occurrences were in 1974, with two occurring in 1975, and the last one occurred in 1978.

4.5.3.3 Failed fuel elements. Failed fuel cladding became a problem in 1965. The off-gas activity rose consistently until it reached 15,000 µc/s, where it leveled off. This level remained esentially constant until 1966. The primary contributors to the high off-gas activity were four developmental fuel bundles that failed. These failures were not expected since the fuel had only reached half of its design life.

No gross fuel failures occurred in 1967. In December, power was reduced after the off-gas activity started to increase. Reducing power preserved fuel integrity. During refueling in February 1968, twenty-nine of thirty-three reload-2 "C" fuel bundles indicated a positive leaking signal after being dry sipped. These bundles were vibratory packed powdered fuel. The off-gas activity again increased in June. During the June refueling, pellet UO_2 rather than powdered UO_2 was loaded into the core. An indication of a clad failure of the new core occurred in October when the off-gas activity again increased. The off-gas activity continued to increase into 1969.

Power was reduced in January and again in February of 1969 in order to reduce off-gas activity. Refueling in April revealed nine failed assemblies. All of the failed assemblies had evidence of significant crud accumulation and crud spalling. Hot cell examinations on two of the fuel rods showed that the accelerated corrosion on the rod surface was driven by local overheating. Since preliminary investigations revealed accelerated corrosion due to high cladding temperatures, the power was temporarily limited to 165 MWt. The reloading of pellet UO_2 and derating the thermal output of the core solved the problem of leaking fuel elements.

4.6 Evaluation of Operating Experience

The major sources of information utilized during this evaluation were (1) forced shutdowns and power reductions and (2) reportable events. Two significant areas were identified in the review of shutdowns and power reductions. These are failed fuel elements and loss of the 138 kV line. Failed fuel was mainly a problem during the 1960's. This problem was solved by replacing powdered fuel with fuel pellets which resulted in derating the core thermal power, changing heat exchanger tube material to reduce corrosion which contributed to crud build-up on the fuel elements, and modifying reactor core flow patterns. The 138 kV line had been lost nine times at what appears to be a constant rate. Three of these events were complete losses of offsite power, a typical number for a plant operating for 19 years. The first two complete LOOPs occurred prior to the installation of the 46 kV line and little is known about these events including their duration. The third LOOP (see Sect. 4.5.2) which was well documented, involved failures in other systems during the transients, however none of these failures impacted the plants' recovery. Offsite power was also restored within 20 minutes, thus minimizing the significance of this event.

There were no significant problems identified through the search of LERs. Events caused by human errors contributed about half of the reports.

The emergency condenser failed on two occasions. Both events involved the failure of a dc operated emergency condenser outlet valve to open, thus rendering one of two emergency condenser loops inoperable. However, one loop is capable of removing decay heat during shutdown.

Overall the operation of Big Rock Point has been satisfactory from a safety point of view. Again, no period was identified where the operation of Big Rock Point posed a threat to the general public.

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Appendix A: Big Rock Point

Part 1. Forced Shutdowns and Power Reduction Tables

Table A1.1 1962 and 1963 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1962) to 1963	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/NSIC(N) Event Category
1)	12/62 to 3/63		<1		Spurious period or flux trip.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
2)	12/62 to 3/63		<1		Spurious period or flux trip.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
3)	12/62 to 3/63		<1		Spurious period or flux trip.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
4)	12/62 to 3/63		<1		Spurious period or flux trip.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
5)	12/62 to 3/63		<1		Spurious period or flux trip.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
6)	12/62 to 3/63		2		Low drum level (control on manual during testing).	B	3	Steam & Power (HA)	Turbine	
7)	12/62 to 3/63		2		Inadvertent simultaneous closure of reactor recirculating pump discharge valves.	G	3	Reactor Coolant (CB)	Valves	N6.0
8)	12/62 to 3/63		29		Low drum level (drum level transient during IPR adjustment).	B	3	Steam & Power (HA)	Instrumentation & Controls	N2.0

Table A1.1 (Continued)

No.	Date (1962 to 1963)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	12/62 to 3/63		50		Low vacuum scram resulting from loss of station power.	A	3	Electric Power (EX)		D2.5
10)	12/62 to 3/63		58		High neutron flux (resulting from pressure transient caused by improper response of bypass valve during genertor trip tests).	B	3	Steam & Power (HE)		N1.2
11)	12/62 to 3/63		58		Main steam bypass system.	A	2	Steam & Power (HE)		N1.1
12)	12/62 to 3/63		6		Main steam bypass system.	A	2	Steam & Power (HE)		N1.1
13)	12/3/62		2		Accidental jarring of steam drum water level control panel.	G	3	Steam & Power (HE)	Instrumentation & Controls	N6.3
14)	2/17/63	2	33		Low steam drum level.		3	Steam & Power (HB)	Vessels	
15)	2/17/63	~20	6		Malfunction of rod drive B-5 due to collet finger assembly.		1	Reactor (RB)	Control Rod Drive Mechanism	D4.3
16)	2/20/63		50		Momentary loss of generator.	B	3	Steam & Power (HA)	Generators	D2.3
17)	4/12/63	4			Failure of a seal ring in the feedwater check valve at the steam drum.	A	1	Reactor Coolant (CH)	Valves	N1.1

Table A1.1 (Continued)

No.	Date (1962) to 1963	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
18)	10.27/63				When resetting a channel scram annunciation, a rod scram occurred.	A	3	Instrumentation & Controls (IA)	Control Rods	N2.0
19)	11/5/63				Electrical short due to a water leak.	A	[illegible]	Instrumentation & Controls (IA)	Control Rods	N2.0

Table A1.2 1964 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1964)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	5/31	750	29		Spurious opening of the bypass valve.	A	3	Steam & Power (HE)	Valves	N1.1
2)	7/1				Spurious trip of channel 2 picoammeter coincided with test of channel 1.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N7.0
3)	9/18		65		Spurious opening of the turbine bypass valve.	A	3	Steam & Power (HE)	Valves	N1.1

Table A1.3 1965 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1965)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	9/17	24	97		Turbine trip and reactor scram due to a loss of 138 Kv load due to a relaying malfunction.	A	3	Electric Power (EA)	Relays	D2.2
2)	9/30	18	97		Steam leak in turbine stage drain line.	A	1	Steam & Power (HA)	Pipes	N1.1
3)	10/30	?	97		Repair minor steam leaks under the turbine.	A	1	Steam & Power (HA)	Pipes	N1.1
4)	10/30	?	97		Modify 22 control rods. (10 others were modified during the shutdown in August.)	A	4	Reactor (RB)	Control Rods	N1.1

Table A1.4 1966 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1966)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/18	120	97		Repair leaking tube in high pressure feedwater heater.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1
2)	2/2		97-26		Power reduction. Tighten packing on valve in vent line from reactor to steam drum and repair recycle valve controls on No. 1 & 2 reactor feed pumps.	A	5	Reactor Coolant (CC) (CH)	Valves Instrumentation & Controls	N3.1 N2.0
3)	2/10		97-83		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
4)	3/22	48	83		Remove valve in vent line from reactor to steam drum.	A	1	Reactor Coolant (CC)	Valves	N3.1
5)	4/1	48	83		Repair 4 leaking tubes in high pressure feedwater heater.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1
6)	5/11	48			Replace cracked tee in control rod drive system.	A	1	Reactor (RB)	Pipes, Fittings	N1.1.1
7)	5/26	48			Repair 4 leaking tubes in high pressure feedwater heater.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1
8)	6/2		97-89		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
9)	6/18	34	89		Repair 4 leaking tubes in high pressure feedwater heater.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1
10)	7/1	~8	75		Repair leaking tubes in high pressure feedwater heater.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1

Table A1.4 (Continued)

No.	Date (1966)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
11)	7/13	~8	75		Repair leaking tubes in high pressure feedwater heater.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1
12)	7/20	~8	75		Repair leaking tubes in high pressure feedwater heater.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1
13)	7/26		75-49		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
14)	8/3	24	49		Blank off high pressure feedwater heater tube sheet to eliminate tube leakage.	A	1	Reactor Coolant (CH)	Heat Exchangers	N3.1
15)	8/8	24	49	LTR 12/20/66	138 Kv breaker opened during a storm. The bypass valve opened but did not prevent pressure buildup and reactor scrammed on high pressure.	H	3	Electrical Power (EA)	Circuit Closures/ Interrupters	D2.2
16)	11/10		~95-55		Power reduction. Seals on No. 2 reactor recirculating pump failed.	A	5	Reactor Coolant (CB)	Pumps	D3.1
17)	11/12	~24	55		Examination and removal of No. 2 reactor recirculating pump.	A	1	Reactor Coolant (CB)	Pumps	N1.1
18)	12/15	72	69		Reinstallation of No. 2 reactor recirculating pump.	A	1	Reactor Coolant (CB)	Pumps	N1.1

Table A1.5 1967 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1967)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/NSIC(N) Event Category
1)	1/20	~12	97		Pressure transient caused by erratic operation of the turbine admission valve caused by the initial pressure regulator.	A	3	Steam & Power (HA)	Instrumentation & Controls	D2.1
2)	1/20	~156	Low		Reactor startup was delayed because rod drive E4 could not be withdrawn. Installed new drive.	A	4	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
3)	1/26	~336	Low		Failure of turbine shaft-driven oil pump which operates the turbine admission valve.	A	1	Steam & Power (HA)	Pumps	N1.1
4)	2/10	26	97		Replaced defective control rod drive D-1.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
5)	2/12		53-0		Power reduction. Repair turbine initial pressure regulator.	A	5	Steam & Power (HA)	Instrumentation & Controls	N1.1
6)	2/13	7	?-0		Power reduction. Repair turbine initial pressure regulator.	A	5	Steam & Power (HA)	Instrumentation & Controls	N1.1
7)	2/14		?-0		Power reduction. Repair turbine initial pressure regulator.	A	5	Steam & Power (HA)	Instrumentation & Controls	N1.1
8)	2/16	7	97-0		Power reduction. Repair turbine initial pressure regulator.	A	5	Steam & Power (HA)	Instrumentation & Controls	N1.1

Table A1.5 (Continued)

No.	Date (1967)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	2/17		?-0		Power reduction. Repair turbine initial pressure regulator.	A	5	Steam & Power (HA)	Instrumentation & Controls	N1.1
10)	3/10	8	96-0		Power reduction. Inspect the generator exciter brushes.	A	5	Steam & Power (HA)	Generators	N1.1
11)	3/10	~6	0		Error during instrument work.	B	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N5.0
12)	3/27	~6	96		Repair steam leaks n packing gland of butterfly valve on discharge of No. 2 recirculating pump.	A	1	Steam & Power (HX)	Pipes, Fittings	N3.1
13)	3/27	~1	0		Short period when attempting to raise reactor pressure.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.0
14)	4/14	21	96		Leaks in packing of the isolation valve for the west steam reference line to the drum level instrumenta-	A	1	Reactor Coolant (CC)	Valves	N3.1
15)	10/26	24	96		Repair steam leak in the bonnet of the high pressure bleeder trip valve.	A	1	Reactor Coolant (CC)	Valves	N3.1
16)	11/25	7	96		Replace offgas filter due to high differential pressure.	A	1	Radioactive Waste Management (MB)	Filters	N1.1.4

Table A1.5 (Continued)

No.	Date (1967)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
17)	12/?		100-78		Power reduction. Offgas activity to pressure fuel integrity.	A	5	Reactor (RC)	Fuel Elements	N4.0
18)	12/?		78-13		Power reduction. Make temporary repairs to stop steam leaks on the turbine trip valve to the high pressure heater.	A	5	Reactor Coolant (CC)	Valves	N3.1
19)	12/?		82-13		Power reduction. Make temporary repairs to stop steam leaks on the turbine trip valve to the high pressure heater.	A	5	Reactor Coolant (CC)	Valves	N3.1

Table A1.6 1968 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1968)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/?		82-?		Power reduction. Repack No. 1 & 2 reactor feed pumps.	A	5	Reactor Coolant (CH)	Pumps	N1.1
2)	1/?		82-?		Power reduction. Repack No. 1 & 2 reactor feed pumps.	A	5	Reactor Coolant (CH)	Pumps	N1.1
3)	1/?		82-?		Power reduction. Repack No. 1 & 2 reactor feed pumps.	A	5	Reactor Coolant (CH)	Pumps	N1.1
4)	4/4	24			Reinstall No. 2 recirculating pump.	A	1	Reactor Coolant (CA)	Pumps	N1.1
5)	4/6		Low		Install new shaft seal cartridge in No. 2 recirculating pump.	A	1	Reactor Coolant (CA)	Pumps	N1.1
6)	4/7	~48	Low		Control rod drive B4 could not be withdrawn from the fully inserted position. It was replaced.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
7)	4/23	6	79		The high-sphere pressure sensors were accidentally bumped.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.3
8)	6/3	~24	83		Repair leaks in unions adjacent to the explosive valves on the reactor poison system.	A	1	Reactor (RB)	Pipes, Fittings	N1.1
9)	6/12		83-75		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0

Table A1.6 (Continued)

No.	Date (1968)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
10)	6/13		75-68		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
11)	9/10	~20	97		Repack No. 2 reactor recirculating pump butterfly valve.	A	1	Reactor Coolant (CB)	Valves	N3.1
12)	9/21	~21	97		High delta P in stack off-gas filter.	B	1	Radioactive Waste Management (MB)	Filters	N1.1.4
13)	10/13	~20	95		Repair 2 steam leaks and replace the high-pressure heater drain valve diaphram.	A	1	Steam & Power (HG)	Pipes, Fittings Valves	N3.1
14)	10/?	~8	Low		While returning to power, control rod B-5 could not be moved from notch 15.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
15)	10/?	~12			Inspect and replace O-rings in control rod flanges.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
16)	10/?	~12			Inspect and replace O-rings in control rod flanges.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
17)	11/6	23	95		Packing leak on the main steam bypass isolation valve.	A	1	Steam & Power (HE)	Valves	N3.1
18)	12/14		95-89		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
19)	12/14	17	95		Packing leak on the steam supply to the condenser air ejectors.	A	1	Steam & Power (HC)	Pipes, Fittings	N3.1

Table A1.7 1969 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/2		89-81		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
2)	1/17	24	81		Steam leak in turbine stage drain heater.	A	1	Steam & Power (HA)	Heat Exchangers	N3.1
3)	2/18		81-70		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
4)	3/1	29	68		Steam leak in valve packing on the air ejection supply line.	A	1	Steam & Power (HA)	Valves	N3.1
5)	3/3	~10	68		Excessive cooling water leakage at the D-3 control rod drive flange.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
6)	3/3	~18			Replace 3 control rod drives. Replace shaft seals on No. 1 reactor recirculating pump.	A	4	Reactor (RB)	Control Rod Drive Mechanisms	N1.1.4
7)	6/7	~24	69		Repack outside gland on the butter-fly valve in the No. 1 reactor recirculating loop.	A	1	Reactor Coolant (CB)	Valves	N3.1
8)	6/21	~24	69		Repair 4 steam leaks in the turbine pipe tunnel area.	A	1	Steam & Power (HB)	Pipes, Fittings	N3.1
9)	7/7	~24	69		Repair leaks in the turbine stage drains and in the B-3 control rod drive cooling water connection.	A	1	Steam & Power (HA) Reactor (RB)	Pipes, Fittings	N3.1 N1.1

Table A1.7 (Continued)

No.	Date (1969)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
10)	8/11	~48	69		Repair steam leaks and inspect for known leakage in the turbine main condenser and core spray heat exchanger.	A	1	Steam & Power (HC) Engineered Safety Features (SF-D)	Heat Exchangers	N3.1 N1.1
11)	10/20	24	69	LTR 2/20/70	High conductivity of the primary coolant caused by previous mal-operation which resulted in over-heating the resin in the cleanup demineralizer.	G	1	Reactor Coolant (CH)	Deminer-alizers	N6.0
12)	11/5	~8	69		Repair steam leak in the turbine stage drain line to the inter-mediate pressure heater.	A	1	Steam & Power (HA)	Pipes, Fittings	N3.1

Table A1.8 1970 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/8	~24	70		Replace off gas filter.	A	1	Radioactive Waste Management (MB)		N1.1
2)	3/30	~8			Turbine problems.	A	1	Steam & Power (HA)	Turbines	N1.1
3)	3/31	~8			Turbine problems.	A	1	Steam & Power (HA)	Turbines	N1.1
4)	4/1	~8	70		Minor adjustments to the turbine initial pressure regulator.	A	1	Steam & Power (HA)	Instrumentation & Controls	N2.0
5)	4/24		70		Leaking core spray heat exchanger tube.	A	1	Engineered Safety Features (SF-D)	Heat Exchangers	N1.1
6)	6/28	72	70		A fault in the 138 Kv transmission line caused a load rejection due to a severe storm. The reactor tripped on high pressure.	H	3	Electric Power (EA)	Circuit Closures/ Interrupters	D2.2
7)	10/5		70-7		Power reduction. Replace solenoid valve assembly on the dirty sump discharge isolation valve.	B	5	Radioactive Waste Management (MA)	Valves	N1.1
8)	10/7	24	70		Repack main steam bypass valve.	A	1	Steam & Power (HC)	Valves	N3.1

Table A1.8 (Continued)

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9)	11/13	24	70	LTR 12/1/70	Plug 3 tubes in the post incident heat exchanger.	A	1	Engineered Safety Features (SB)	Heat Exchangers	N3.1
10)	11/14	4	Low		Erratic operation of the period amplifier in the channel 4. Log N neutron monitoring equipment caused a short period scram.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
11)	12/3	10	70		A fault in the 138 Kv transmission line caused a load rejection due to a severe storm. The reactor tripped on high pressure.	H	3	Electric Power (EA)	Circuit Closures/ Interrupters	D2.2

Table A1.9 1971 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/23	40	70		Repair turbine condenser tube leaks and a steam leak in the intermediate - pressure heater line.	A	1	Steam & Power (HC)	Heat Exchangers (Condensers)	N3.1
2)	2/2	216	70-63		High seal temperature on the No. 2 recirculating pump.	A	5	Reactor Coolant (CB)	Pumps	N1.1
3)	4/20	24	70		Repair steam leak from the packing of the butterfly valve located on the discharge of the No. 1 reactor recirculating pump.	A	1	Reactor Coolant (CB)	Valves	N3.1
4)	4/2[illegible]	24	70		Make adjustments to the turbine initial regulator.	A	1	Steam & Power (HA)	Instrumentation & Controls	N1.1
5)	5/12	21	70		Load rejection due to a fault in the 138 Kv transmission line caused by a corner strain pole which had been cut half way through and a guy wire which had been cut.	H	3	Electric Power (EA)	Circuit Closures/ Interrupters	D2.2
6)	6/2	25	70		Steam leak in the turbine stage drain piping to the high pressure heater.	A	1	Steam & Power (HA)	Pipes, Fittings	N3.1
7)	9/22	18	70		Loss of all major rotating equipment due to accidental tripping of the 2400 volt station power relays.	G	3	Electric Power (EB)	Circuit Closures/ Interrupters	D2.3
8)	9/28	14	70		High flux scram following loss of the 138 Kv transmission line attributed to a local storm.	H	3	Electric Power (EA)	Circuit Closures/ Interrupters	D2.2

Table A1.9 (Continued)

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NS[illegible](N) Event Category
9)	10/18		70-53		Power reduction. Failure of No. 2 reactor recirculating pump seals necessitated pump shutdown.	A	5	Reactor Coolant (CB)	Pumps	N1.1
10)	10/23	33	57		Shutdown to replace the No. 2 recirculating pump seal cartridge.	A	1	Reactor Coolant (CB)	Pumps	N1.1
11)	11/26	11	57		Failure of the linkage arm of the turbine trip solenoid caused a turbine and generator trip.	A	1	Steam & Power (HA)	Instrumentation & Controls	D2.3

Table A1.10 972 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/25	80	55	LTR 3/3/72	Turbine trip on overspeed due to no load. This was caused by the Big Rock Point relaying scheme not clearing when a system line fault occurred.	A	3	Electric Power (EX)	Relays	D2.2
2)	2/11	8	53		Adjust the initial-pressure regulator which would not regulate the turbine control valves effectively at low power.	A	1	Steam & Power (HB)	Instrumentation & Controls	N2.0
3)	5/15	60	70		Primary coolant leakage at the B 5 control rod drive flange. During maintenance the teflon O-ring had been replaced with a new type silver plated inconel O-ring.	A	1	Reactor (RB)	Pipes, Fittings	N1.1.3
4)	5/18-5/19		70-?		Several power reductions to isolate a leak into the component cooling water system. The leak was traced to the No. 1 reactor recirculating water pump seal cooling water heat exchanger.	A	5	Reactor Coolant (CB)	Heat Exchangers	N3.1
5)	5/19		70-67		Power reduction. Shutdown No. 1 reactor recirculating water pump due to leaking heat exchanger.	A	5	Reactor Coolant (CB)	Heat Exchangers	N3.1
6)	6/10	15	67		Replace No. 1 reactor recirculating pump seal heat exchanger.	A	1	Reactor Coolant (CB)	Heat Exchangers	N1.1
7)	6/17	~20	67		Replace seal cartridge on No. 1 reactor recirculating pump.	A	1	Reactor Coolant (CB)	Pumps	N1.1

Table A1.10 (Continued)

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	6/18	~8	71		Replace leaking offgas rupture diaphram.	A	1	Radioactive Waste Management (MB)	Pipes, Fittings	N1.1
9)	7/6	3	83		Low drum level scram due to inability to maintain an adequate feedwater supply during a load rejection test.	B	3	Reactor Coolant (CH)		D2.7
10)	7/27		83-70		Power reduction. Scram valves were inadvertently opened while working on a scram valve solenoid. This caused rod drive E-1 to fully insert.	B	5	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
11)	7/29	30	83		Repack the turbine main steam bypass valve.	A	1	Steam & Power (HE)	Valves	N3.1
12)	9/30	40	83		Repair steam leak on the turbine high pressure extraction line.	A	1	Steam & Power (HA)	Pipes, Fittings	N3.1
13)	11/6		83-13		Power reduction. Pump bearing failure caused the clean-up system pump to fail.	A	5	Reactor Coolant (CG)	Pumps	N1.1
14)	11/6		83-13		Power reduction. Replace clean-up system pump due to bearing failure.	A	5	Reactor Coolant (CG)	Pumps	N1.1
15)	11/12	~8	Low		Short period scram because of a high notch worth in sequence during withdrawal of control rod B-5.	C	3	Reactor (RB)	Control Rod Drive Mechanisms	D4.3
16)	11/23	33	83		Excessive leakage through the O-ring on control rod drive C-5.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1

Table A1.10 (Continued)

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
17)	12/16	26	83	LTR 3/23/73	Repair a leak in the feedwater line blank/flange.	A	1	Reactor Coolant (CH)	Pipes, Fittings	N3.1
18)	12/30		?-68		High activity in plant off gas. (Fuel cladding failures.)	A	5	Reactor (RC)	Fuel Elements	N4.0

Table A1.11 1973 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/20	25	66		Leak in the packing of the reactor cleanup system discharge valve to the No. 1 reactor recirculating pump discharge piping.	A	1	Reactor Coolant (CG)	Valves	N3.1
2)	5/3		91-39		Power reduction. System substation work.	B	5	Electric Power (EB)	Other (XX)	N9.0
3)	5/12		91-39		Power reduction. System substation work.	B	5	Electric Power (EB)	Other (XX)	N9.0
4)	5/21		91-83		Power reduction. Flux tilting test to determine location of leaking fuel bundles.	B	5	Reactor (RC)	Fuel Elements	N4.0
5)	6/29		91-87		Power reduction. In-core detectors No. 12 and No. 14 were alarming. Later tests indicated that no thermal limits had been exceeded and these were recalibrated.	A	5	Instrumentation & Controls (IB)	Instrumentation & Controls	N2.3
6)	7/20		92-3		Power reduction. Leak in component coolant line to the motor thrust bearing of No. 2 recirculating pump.	A	5	Auxiliary Water (WB)	Pipes, Fittings	N3.1
7)	8/16		92-13		Power reduction. Leak in flex line from heat exchanger on the recirculating pump.	A	5	Auxiliary Water (WB)	Pipes, Fittings	N3.1

Table A1.11 (Continued)

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	9/19		92-13		Power reduction. Cleanup pump stopped and could not be re-started. Reduced power to enter the recirculating pump room to isolate the cleanup system.	A	5	Reactor Coolant (CG)	Pumps	N1.1
9)	9/22		92-13		Power reduction. Enter recirculating pump room to valve the cleanup system into service after having replaced cleanup pump.	A	5	Reactor Coolant (CG)	Pumps	N1.1
10)	12/3		92-76		Power reduction. High offgas release rate.	A	5	Reactor (RC)	Fuel Elements	N4.0
11)	12/6		76-70		Power reduction. High offgas release rate.	A	5	Reactor (RC)	Fuel Elements	N4.0
12)	12/8	72	70		Packing failure on the level instrumentation lower root valve at east end of reactor steam drum.	A	1	Reactor Coolant (CH)	Instrumenta-tion & Controls	N2.0
13)	12/8				Leaking tubes on the emergency condenser and modify baffle plater.	A	4	Engineered Safety Features (SB)	Heat Exchangers	N1.1

Table A1.12 1974 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
	(continuation)									
	12/8/73	253			Repair emergency condenser. Modify baffles in inlet water box.	A	4	Engineered Safety Features (SB)	Heat Exchangers	N1.1
1)	5/5		98-93		Power reduction. Flooding of intermediate pressure feedwater heater and condenser vacuum upset.	A	5	Reactor Coolant (CH)	Heat Exchangers	N1.1
2)	5/17		95-83		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
3)	5/20		83-70		Power reduction. Fuel cladding failure.	A	5	Reactor (RC)	Fuel Elements	N4.0
4)	6/2	48	70		Steam leak on 3 in. drain line from HP section of turbine to HP feedwater heater.	A	1	Steam & Power (HH)	Pipes, Fittings	N3.1
5)	6/5	744		UE74-07 UE74-08	Control rod drives stuck. Other maintenance performed.	A	4	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
6)	9/28	12	83-64		Power reduction. Remove No. 1 condensate pump for replacement of two upper motor thrust bearings.	A	5	Steam & Power (HC)	Pumps	N1.1
7)	10/6		83-?		Power reduction. Failure of another in-core detector. This reduced the number of operational detectors to 10. Plant was placed in coastdown mode.	A	5	Instrumentation & Controls (ID)	Instrumentation & Controls	N1.1

Table A1.12 (Continued)

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	11/21	7	83-13		Power reduction. Repair turbine intermediate pressure extraction line to intermediate pressure feedwater heater.	A	5	Steam & Power (HC)	Pipes, Fittings	N3.1
9)	11/23	11	88-13		Power reduction. Repair turbine intermediate pressure extraction line to intermediate pressure feedwater heater.	A	5	Steam & Power (HC)	Pipes, Fittings	N3.1

Table A1.13 1975 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1975)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/7		83-80		Power reduction. Encroachment of the 90% MAPLHGR limit on "F" type fuel.	F	5	Reactor (RB)	Fuel Elements	N8.0
2)	1/16	3421	80	AO-1-75 (1-27-75)	Unit was shut down when it was found that design and QA deficiencies existed in instrumentation for the post incident cooling system.	D	1	Engineered Safety Features (SB)	Instrumentation & Controls	N8.3
3)	9/25	48	80-70		Power reduction. Repair a ground in a wiring junction box to No. 2 condensate pump motor.	A	5	Steam & Power (HC)	Electrical Conductors	N1.1
4)	10/19		80-42		Power reduction. Modifications to the Livingston substation.	H	5	Electric Power (EA)	Transformers	N9.0
5)	10/19		42-11		Power reduction. The turbine bypass valve opened partially due to failure of the initial pressure regulator. Turbine governor control was also unresponsive.	A	5	Steam & Power (HE)	Instrumentation & Controls	N1.1
6)	10/30	6	80-7		Power reduction. Leak in HP stage drain line from HP turbine to HP heater. IPR failed during power reduction.	A	5	Steam & Power (HE) (HA)	Pipes, Fittings	N3.1 N1.1
7)	11/13	45	83		Plug leaking tubes in main condenser.	A	1	Steam & Power (HC)	Heat Exchangers	N3.1

Table A1.13 (Continued)

No.	Date (1975)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8)	12/3		72-?		Power reduction. Attempt to repair leak in high pressure turbine casing reducer.	A	5	Steam & Power (HA)	Pipes, Fittings	N3.1
9)	12/6	50	74	AO-75-27	Repair leak in high pressure turbine casing reducer and perform control rod drive testing.	A	1	Steam & Power (HA)	Pipes, Fittings	N3.1

Table A1.14 1976 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1976)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/31	3215	~70		Installation of the Reactor Depressurization system and minor modification to the ECCS.	D	1	Engineered Safety Features (SF)	Pipes, Fittings	N8.0
2)	7/28	18	Low		Pinhole leak in valve on air ejector system.	A	1	Radioactive Waste Management (MB)	Valves	N3.1
3)	8/11	66	88		The TG Initial Pressure regulator failed resulting in high flux and a reactor trip.	A	3	Steam & Power (HA)	Circuit Closures/ Interrupters	D2.1
4)	11/22	24	88-69		Power reduction. Repack No. 1 reactor feed pump inboard shaft seal.	A	5	Reactor Coolant (CH)	Pumps	N1.1

Table A1.15 1977 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1977)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	2/6	7	85-42		Power reduction. Repair steam leak on the turbine extraction line of the IP heater.	A	5	Steam & Power (HA)	Pipes, Fittings	N3.1
2)	4/4	24	85-?		Power reduction. Investigate abnormal noise in No. 2 reactor feed pump.	H	5	Reactor Coolant (CH)	Pumps	N1.1
3)	10/29	88	80		Turbine control problems.	A	1	Steam & Power (HA)	Turbines	N2.0

Table A1.16 1978 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1978)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	1/13	484			Repairs to control rod drive B4.	A	1	Reactor (RB)	Control Rod Drive Mechanisms	N1.1
2)	3/20		90-?	RO 78-16	Power reduction. Investigate source of water leakage. Visual inspection indicated that it was from CRD cooling flange O-rings.	A	5	Reactor (RB)	Pipes, Fittings	N1.1
3)	4/7	43	90	RO 78-18	Faulty tone relaying equipment resulted in the opening of the 199 OCB even though the 138 KV power line remained energized. Reactor scrammed on low condenser vacuum.	A	3	Electric Power (EB)	Circuit Closures/ Interrupters	D2.2
4)	4/15		~90-~50	RO 78-21	Power reduction. Modification to the Emmett Substation.	H	5	Electric Power (EA)		N9.0
5)	4/25		90-51		Power reduction. Loss of tone relaying equipment due to a brush fire off site.	H	5	Other (XX)		N9.0
6)	5/31	22	90		Wiring error during modification to an offsite substation resulted in tripping breaker to 138 KV line.	H	3	Electric Power (EA)	Circuit Closures/ Interrupters	D2.2
7)	9/4	111	Low	RO 78-035	Unacceptable test results for containment supply ventilation valve leak rate test. Valves were repaired.	A	1	Engineered Safety Features (SB)	Valves	N1.1
8)	9/9	12[illegible]1	Low	LER 78-038	Control rod drive problems - high temperature encountered.	A	2	Reactor (RB)	Control Rod Drive Mechanisms	N1.1

Table A1.17 1979 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	2/2	18	87	LER 79-001	Replace valve disc with modified design, after unacceptable leak rate test on containment ventilation valve.	A	2	Engineered Safety Features (SA)	Valves	N1.2
2)	4/17	315	Low	LER 79-018	High pressure reactor trip caused by the turbine bypass valve failing to open.	A	3	Steam & Power (HE)	Valves	N1.1
3)	4/17	4847		LER 79-020	Correct inlet diffuser vibration problem in reactor vessel and repair leak in CRD housing.	A	4	Reactor (RA)	Diffusers	N1.1
4)	11/6	54	Low		Replace recirculating pump seal.	A	1	Reactor Coolant (CB)	Pumps	N1.1
5)	11/6	3			Repair leaks in turbine bypass drain line.	A	4	Steam & Power (HE)	Pipes, Fittings	N3.1
6)	12/31	2			Regulatory shutdown for checking relief valve position. Manual reset of containment isolation and radiation monitors.	D	1	Instrumentation & Controls (IB)	Instrumentation & Controls	N8.0

Table A1.18 1980 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1980)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
	(continuation)									
	12/31/79	296			Regulatory shutdown to implement requirements of NUREG-0578.	D	4	Instrumentation & Controls (IB)	Instrumentation & Controls	N8.0
1)	1/13	4	Low		Failure of intermediate power range monitor.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.0
2)	1/13	5	Low		Failure of intermediate power range monitor.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.0
3)	1/13	15	Low		Intermediate power range trip on period due to prompt effect.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.0
4)	1/15	15			Failure of intermediate pressure regulator.	A	3	Steam & Power (HA)	Instrumentation & Controls	D2.1
5)	1/18				Power reduction. Intermediate pressure regulator test.	A	5	Steam & Power (HA)	Instrumentation & Controls	N1.1
6)	4/17	27	88-?		Power reduction. Repair piping in high pressure turbine drain line.	A	5	Steam & Power (HA)	Pipes, Fittings	N3.1

Table A1.19 1981 Forced Shutdowns and Power Reductions at Big Rock Point

No.	Date (1981)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1)	2/2	52	0		Remained off-line due to generator exciter problems (forced).	A	9	HA	Turbines	N1.2
2)	4/20	42	100-?		Power reduced to replace clean-up pump.	A	5	WX	Pumps	N1.1
3)	5/5	12/6	100-?		Power reduction to valve out clean up pump for maintenance.	B	5	WX	Pumps	N1.1
4)	6/25	21.9	100-?		Power reduction for control rod drive performance testing (on-line).	B	5	RB	Control Rod Drive Mechanisms	N1.1

Appendix A: Big Rock Point

Part 2. Reportable Event Coding Sheets

Table A2. 1 Coding Sheet for Reportable Events at Big Rock Point - 1966

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
66-1	14892	050166	122066	C	RB	Z,J	-	B	AI,AG	B,C	C4	Cracking in CRD hyrraulic system and two CRs fail to withdraw (24646).
66-2	10568	062266	070466	D	RB	I,J	-	B	AU	B	N	Leak into CRD would unlock collet allowing CR to drift out.
66-3	11038	080866	122066	B	ED,HE	F	-	B	BJ,OD	I,F	S7	Loss of offsite power and rupture of condenser rupture diaphragm (14893).
66-4	16521	120066	120066	-	CB	DD	-	A	AK	E	N	New approach to recirculation pump maintenance.
66-5	-	120066	061781	-	CG	Z	-	A	BO,AV	D	N	Parts of clean-up system piping replaced due to cracks.
66-6	23393	120066	122066	B	CH	MM	-	B	AU	D	N	Feedwater heater tube failures.

Table A2. 2 Coding Sheet for Reportable Events at Big Rock Point - 1967

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
67-1	16522	012067	010067	B	RB	J	-	B	BR,AG	D,G	N	Reactor scram due to pressure transient, restart was inhibited by jammed CRD.
67-2	27476	050067	050067	C	RC	R	-	C	AQ	D	C7	Fuel element leaking due to crud (27477).
67-3	19274	091267	110667	-	MB	OC	-	-	AW,OD	D	C3	Off gas system had leaky diaphram, exposure to worker fixing it.
67-4	22828	122567	010868	B	RB	I,J	-	B	AG	D	C7	CRD rod F-5 would not withdraw but would insert.
67-5	24201	122567	030568	B	RB	I,J	-	B	AG	D	C7	Rod F-5 jammed by piece of steel.

Table A2. 3 Coding Sheet for Reportable Events at Big Rock Point - 1968

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
68-1	30032	040068	043068	B	RC	R	-	B	AU	D	C7	Two fuel bundles leaked.
68-2	25305	040668	042368	D	RB	I,J	-	B	AG	D	C7	Rod B-4 would not withdraw
68-3	31307	062468	071168	D	CB	DD,OO	-	A	AW,OD	A	C3	Personnel overexposed during repair of recirculation pump.
68-4	33048	073068	070068	-	CB	BB	-	B	BU	D	N	High steam drum conductivity.
68-5	61319	110068	121671	B	RC	R	-	B	AQ,BL	B	N	Crud buildup causes fuel failure.
68-6	-	113068	020469	-	EE	N	-	C	BD,CA	B	N	DG linkage pin designed wrong.
68-7	31010	120068	122768	B	RC	R	-	B	AU	D	C7	Fuel elements leak and power reduced due to off-gas.

Table A2. 4 Coding Sheet for Reportable Events at Big Rock Point - 1969

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
69-1	-	022069	033169	-	EE	N	-	C	EC	G	C7	EDG tripped on overspeed due to improper overspeed trip seet point.
69-2	-	060069	122269	-	EE	N	-	C	BE,BL	D	C7	EDG overheated due to fish lodged in cooling water pump suction pipe.
69-3	-	102069	022070	B	CX	-	A,O	B	EG	D	N	Alarm circuit on recorder failed to warn RO of high coolant temperature.

Table A2. 5 Coding Sheet for Reportable Events at Big Rock Point - 1970

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
70-1	42001	020070	022470	-	IA	-	I	-	BC	B	N	Moved water level sensors to area of lower radiation for accessibility.
70-2	57230	080670	100870	B	EE	N,T	C	C	EG	D	C1	Diode failure caused DG to fail to develop proper voltage.
70-3	-	100170	100870	-	EE	N	-	C	BD	D	C7	EDG failed to start due to lack of lube oil supply to governor.
70-4	60903	111370	120170	D	HC	H,MM	-	D	AU,OH	D	C3	Condenser tube leaked and noncondensible gas drawn into cooling water. 1.04 Ci released to canal.

Table A2. 6 Coding Sheet for Reportable Events at Big Rock Point - 1971

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
71-1	64240	020071	061771	C	CG	Z	-	A	BO,AY	D	N	Section of cleanup system piping replaced due to cracks (65548).
71-2	74353	030271	032671	D	RB	I,J	-	C	HD,AG	D	N	CRD stuck in inserted position due to roller being stuck in drive.
71-3	63790	052671	060771	B	RB	I	-	B	AG	D	E	Control rod C-3 would not withdraw but would insert.
71-4	65547	071571	081171	B	EE	N	-	C	BE,BL	D	C1	DG fails to run due to high cooling water temperature.

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

Table A2. 7 Coding Sheet for Reportable Events at Big Rock Point - 1972

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
72-1	39024	012572	030372	B	EA	00	-	B	EF	I	S7	Off-site power lost during storm and switchgear malfunctioned.
72-2	71399	032872	051172	C	RB	00	-	C	AM	B	C4	Liquid poison system explosive valve fails to fire.
72-3	70037	040072	041972	C	RC	-	F	A	AR	B	N	Outer encapsulation of neutron sources fail.
72-4	73801	052572	062372	B	EE	N	-	C	BD,BC	H	C1	Diesel generator fails to start due to low pressure set point.
72-5	72453	061072	062672	B	MB	00	-	C	OA	D	N	Off gas isolation valve fails to seal.
72-6	75136	072972	091372	D	RB	G	-	-	BL	B	N	Failure of startup channels due to faulty cable.
72-7	74355	082872	090172	B	MC	Z	-	C	BU	D	N	Off gas system holdup time shorter than expected (75077).
72-8	75973	083172	092672	B	SD	00	-	-	BB	C	N	Containment isolation valve fails to open due to faulty solenoid.
72-9	-	091472	022873	B	EE	N	-	C	BC	D	C7	EDG failed to achieve rated voltage due to a shorted exciter armature.
72-10	77446	112372	122072	B	SD	00	-	B	BB	C	N	Containment isolation valve fails to open due to solenoid failure.
72-11	77861	121672	032373	B	CE	H	-	B	AI	D	C3	Leak into emergency condenser secondary yields radiation release.

Table A2. 8 Coding Sheet for Reportable Events at Big Rock Point - 1973

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
-	79595	030073	032673	C	RC	F	-	-	AL	B	N	Cobalt target rods become loose.
-	80131	030373	040573	D	CD	00	-	-	BB	D	N	MSIV packing was binding the valve stem.
A07303	74830	040573	050873	C	CE	00	-	-	BA	G	C8	Emergency condenser outlet valve fails to open.
A07308	74830	040573	050873	C	-	-	T	-	EH	D	N	Time delay relay switch set point drift.
A07307	74830	040573	050873	C	HC	-	T	-	EH	D	N	High condensor pressure switch set point drift.
A07304	74830	040573	050873	C	SD	-	T	-	EH	D	N	Reactor enclosure high pressure switch set point drift.
A07306	74830	040573	050873	C	SD	-	T	-	EH	D	N	Reactor building vacuum relief pressure switch set point drift.
A07305	74830	040573	050873	C	SFC	-	T	-	EH	D	N	High reactor pressure scram switch set point drift.
A07313	80732	041973	051873	B	EE	N	-	C	BL,AW	D	C1	DG shutdown due to high coolant temp.
-	74354	050073	050273	-	MC	-	-	B	OD	A	C3	Radiation level at control fence is high.
-	87052	101773	112773	B	SD	00	-	C	AU	D	N	Sphere vent valve operator reserve nitrogen supply leaked.
-	85568	102373	112073	B	FA	R	-	-	OK	A	N	Spent fuel rod found on spent fuel pool floor (91119).
A07311	85590	110173	110273	D	MB	00	-	-	BC	A	N	Stack off-gas isolation valve left open.

Table A2. 8 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A07312	85590	110273	111473	D	HH	-	T	B	EI	G	N	Calibration errors.
A07314	85573	110273	111473	D	ID	-	L	C	EI,OC	A	N	Instrument calibration errors on neutron-monitoring system.
A07313	85590	110373	111373	D	ID	-	L	B	EF	G	N	Calibration errors.
A07316	87053	111173	112673	B	SF	H	-	-	AU,AE	D	N	Leak in emergency condenser tubes, divider plate warped (87091).
-	88106	113073	012174	D	MB	OO	-	B	OA,AW	B	N	Off-gas isolation valve still leaking.

Table A2. 9 Coding Sheet for Reportable Events at Big Rock Point - 1974

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
-	88330	010874	021174	D	BB	P	N	B	BC	E	N	Stack gas effluent monitor installed wrong.
A07401	89266	030174	031274	B	ID	-	L	B	EG	D	N	Neutron flux level instrumentation malfunctions.
A07402	89319	030774	031874	B	EE	N	-	C	BD	G	C1	Diesel generator fails to start.
A07403	89745	032374	040374	D	RB	J	-	C	EI	B	N	CRD withdrawal time less than limit.
A07404	89747	033174	040474	D	IB	-	-	C	OC	A	N	Reactor protection logic system test performed 5 days late.
UE7402	90650	033174	043074	D	RB	I,J	-	B	HD,AG	D	N	Control rod blade lower roller came loose and CRD stuck.
A07405	-	040474	040574	C	CE	U	-	-	OK	H	N	Failed to check core spray heat exchanger as required.
UE7404	91120	040674	050774	D	RC	-	F	B	BO	C	N	Anomalies in cobalt distribution in target rods.
A07406	90374	040774	041774	C	SFD	-	T	B	AW	D	N	Backup core spray system pressure switch leaks water.
-	90576	041074	041874	C	RB	I	-	-	AC	C	N	Fabrication error on several control rods.
A07407	90577	041174	042374	C	EE	N	-	C	CA	G	C1	Diesel generator starting motor mechanism fails.
A07408	-	041174	041674	-	MB	OO	-	B	BC	E	N	Off-gas drain valve improperly adjusted.
A07409	91000	042374	050374	C	MB	OO	-	C	OA	B	N	Off-gas isolation valve fails to seat properly.

Table A2. 9 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A07404	91121	042674	050674	C	SD	OO	-	C	AX,AL	E	N	Vent valve leaks due to improper installation.
A07410	-	050074	050674	D	SD	OO	-	C	AX,BC	G	N	Containment vent valve flange bolt not tightened and leaks.
A07411	91150	050174	051374	C	SD	-	T	C	EH	B	N	Containment vacuum pressure switch set point drifts.
A07412	91151	050374	051374	D	-	-	-	-	OK	A	N	Startup checklist not completed just prior to critical approach.
A07413	91147	050474	051674	D	RB	J	-	C	EI	D	N	CRD withdrawal time less than limit.
A07414	91667	050774	052374	B	ID	-	F	A	OJ	H	N	During irradiation of flux wires, reactor power increased.
A07415	92611	053174	061074	B	EE	N,DD	-	C	BE,AR	D	N	DG transfer pump fails due to key on pump shaft corroding.
UE7406	92438	060074	061074	-	SD	E	-	C	HA	B	N	High flow on plant exhaust fan.
A07416	92612	060374	061374	D	RB	J	-	C	EI	D	N	CRD withdrawal time still less than limit.
A07417	92613	060474	061474	D	IB	-	T	C	AR	D	N	Scram dump tank level switch fails.
UE7407	94371	060474	070574	D	RB	J	-	C	AG	D	N	CRDs stick due to wedged rollers and bolts (UE7408).
UE7410	94750	060774	072674	C	RA	O	-	A	AD	G	N	Reactor baffle plate latching bolts shear.
A07419	94393	060874	072674	D	RB	J,DD	-	B	AT	D	N	Water to CRD pump exceeded drain capacity resulting in flooding.

Table A2. 9 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
UE7409	90651	060874	070374	C	RC	R	-	A	AR	D	N	Neutron source material in vessel accelerated fuel degradation (94372).
AO7418	-	061274	061374	C	MX	R	-	C	OK	H	N	Dry sipped wrong fuel bundle.
AO7421	-	070774	072374	C	-	-	-	-	OK	A	N	Failed to report UE7410 within 30 days.
AO7422	94751	071274	072674	C	SD	OO	-	A	OK,OC	A	N	Solenoid valves replaced but not tested for integrity.
AO7420	94752	071574	072574	C	SHB	OO	-	A	OK	A	C8	Post-incident system supply root valves tagged out during refueling.
UE7411	94915	071874	081674	C	IC	-	P	B	BY	D	N	Relay burned causing coil to overheat closing isolation valves.
AO7423	95542	091774	092774	B	SD	OO	-	C	OK	A	S6	Test fixture on containment emergency escape lock left installed on lock.
UE7412	97138	101574	111474	-	MC	-	O	B	OK	B	C4	Off-gas flow recorder to be rescaled to conform with correct specifications.
UE7413	97513	102274	112174	-	FD	R	-	C	OK	A	N	Higher enriched fuel than expected inserted in a fuel rod.
AO7424	97496	110774	111874	B	EE	C	R	C	EA	C	C1	Defective diode causes battery charger to fail.
AO7425	97742	111474	112674	B	EE	N	-	C	BD	A	C1	DG did not start due to corroded battery terminals.

Table A2.10 Coding Sheet for Reportable Events at Big Rock Point - 1975

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A07501	93277	011675	012775	B	IB	-	I,M	B	OA	B	C4	Reactor water level sensors and pressure sensors design deficient.
UE7501	99662	011775	021175	D	RB	J	-	A	AG	G	N	CRD jammed in fully inserted position.
A07503	93505	011875	013175	D	RB	J	-	C	EI	D	N	CRD withdrawal time less than limit.
UE7502	93506	012275	013175	D	SD	Z	-	A	OD,OH	A	C3	Radioactive water poured down floor drain.
AC7502	100044	012375	022175	D	RA	O	-	A	AL	B,E	C4	Bar beam clamplock bolt missing on locking device for lower grid bars.
A07504	93504	012475	020375	-	FD	E	-	-	OK	A	N	Safety evaluation of dry sipping technique to be reperformed.
A07505	-	013075	021075	D	CC	Z	-	C	AV	E	N	Weld defect in main steam line.
A07507	100043	020675	022475	D	CE	Z	-	B	AC	C	C4	Emergency condenser outlet pipe cracked.
A07508	101151	031875	033175	D	SD	OO	-	C	AU,BC	G	N	Containment vent valve leaks during test.
A07509	102299	041075	042175	D	EE	N	-	C	BD	D	C1	DG fails to start.
B07603	112729	051675	040576	C	SFD	Z	-	-	AO	G	N	Defective weld in core spray piping.
A07511	103070	052075	053075	D	HC	-	T	C	EH	B	C4	Condenser pressure switch cannot be set low enough.
A07512	103186	052175	060275	D	SFD	OO	-	C	AL	B	C4	Core spray valve operator lock nuts loose.

Table A2.10 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
A07513	103187	052375	060275	D	CE	OO	-	C	AL	B	C4	Emergency condenser outlet valve operator lock nut loose.
A07514	103206	052675	060575	D	SHA	OO	-	C	AU,AI	D	N	Containment vent supply valve leaks.
A07515	103482	053075	061075	D	SD	OO	-	C	AU	A,C	N	Containment isolation valve leaks.
A07516	104210	053075	071775	D	SI	OO	-	-	OK	A	N	Valve inspections and repair procedures being reviewed.
UE7503	103702	060675	063075	D	SHB	DD	-	-	OK	B	C4	Procedures for post-incident system conflict with core spray system.
A07522	106452	070075	092275	B	EB	F	-	A	OK	A	N	During construction power moved from one panel to another.
A07517	104809	071875	073175	B	MA	-	-	-	OC	H	N	Discharge canal water not analyzed due to no sample taken.
UE7504	105553	072575	082575	B	RB	J	-	C	AG	D	N	CRD would not withdraw further.
A07518	105842	082575	090475	B	RB	I	-	-	OK	A	N	Control rod worth calculations contain errors.
UE7505	106453	083075	092375	B	MC	C	-	C	EG	D	N	Off-gas monitor failed to trip on signal.
A07519	106299	090075	091875	B	CG	OO	-	B	OK	B	C4	Valves rated lower than design limits require.
A07521	106298	090975	091975	B	SD	OO	-	-	OK	A	C8	Containment isolation valves not tested properly due to plant drawing errors.

Table A2.10 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
AO7520	106297	090975	091975	B	EF	AA	-	B	OK	A	N	Load added to light panel due to unapproved circuit change.
AO7523	106986	092575	100975	B	FX	R	-	-	OK	A	N	Unlicensed reactor fuel received.
AO7526	108251	102475	112475	B	AB	Z	-	A	OK	A	N	Changes to fire system without authorization.
AO7524	100082	110075	111775	-	EX	F	-	-	OK	A	N	No analysis performed on additional load to breaker.
AO7525	108250	111375	112475	D	HC,RB	H,A	-	A	OK	H	C8	Reactor pressure reduced for work on condenser and accumulator to CRD removed in violation.
AO7527	108805	120675	121675	D	RB	J	-	C	OK	H	N	CRD scram tests performed without use of written procedures.
AO7529	108807	120675	121675	D	RB	Z	-	C	AU,AI	D	N	CRD pump discharge piping leaks.
AO7528	108806	120775	121675	D	RB	J	-	C	EI	D	N	CRD withdrawal time less than limit.
AO7530	109196	121875	122675	B	-	-	-	-	OK	A	N	Construction crew began digging without a work package.

Table A2.11 Coding Sheet for Reportable Events at Big Rock Point - 1976

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
T7601	110357	011976	020276	B	SD	-	M,T	C	OA	B	C1	Pressue sensors have too low design pressure rating.
LER7602	111650	020276	030176	C	ED	F,OO	-	A	OK,BG	H	N	Power supply to core spray valves not tagged out as required.
RO7604	113200	032476	041576	C	EE	N	-	C	BE	D	C1	DG tripped due to high cooling water temperature.
RO7605	113277	032776	040976	C	CB	OO,Y	-	C	AV,AR	C	N	Surface cracks on steam drum relief valve nozzles (116898).
RO7606	113550	041776	050376	C	SHA	OO	-	C	AU,BC	D	N	Containment vent supply valves leak.
RO7607	113982	042876	051276	C	SD	OO	-	C	BB	D	N	Resin sluice line isolation valve failed to close.
RO7608	115042	051676	060976	D	EE	N	-	B	BE	D	C1	Emergency DG tripped while supplying load due to high cooling water temperature.
RO7609	115066	051676	060976	D	EE	N,F	-	B	EA	B	N	DG breaker interlock did not function automatically due to wrong fuse.
RO7610	115453	052876	062576	D	RB	-	T	C	EH	D	N	Set point drift on CRD accumulator pressure switch.
RO7611	-	060576	070276	D	EE	N	-	-	OK	A,B	N	DG control circuit completed without review, wrong fuse size used.
RO7612	115737	061976	070276	D	SHA	OO	-	C	AU,AQ	D	N	Containment vent supply valves leak during test.

Table A2.11 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
B07613	115880	062076	071976	D	IB	00	I	C	OK	G	N	Reactor water level instruments in error due to equalizing valve left open.
B07614	115881	062176	071976	D	SFA	00	-	C	AW	D	N	Reactor depressurizing system valves leak.
B07615	116535	063076	073076	D	BC	C	-	B	EC	D	N	Battery charger fails and battery voltage reduced.
B07616	116880	070476	080476	D	RB	J	-	C	AG	G	N	CRD fails to withdraw.
B07617	116881	071876	080476	D	SFA	C	-	C	BU	G	C7	Specific gravity of station battery acid low due to addition of water.
B07618	116786	072276	081976	D	EE	N	-	C	BI	D	C7	Starting time of DG exceeds limit.
B07619	116787	072276	081976	D	SFA	C	-	C	BU	G	C7	Water added to RDS battery and lowers its specific gravity.
B07620	116798	072976	081976	B	SFA	C	-	C	BU	G	C7	Water added to RDS battery and lowers its specific gravity.
B07621	117676	080576	090376	B	EE	N	-	C	BI	D	C7	DG failed to start within time limit.
B07623	117677	080576	090376	B	EE	N	-	B	OK,OC	H	C8	DG returned to operable status without retesting.
B07622	-	081276	090776	D	EE	N	-	C	BD	D	N	DG failed to start due to battery cable faults.
B07624	-	081376	090776	D	IB	-	S	B	EG	G	N	Power range neutron monitor had wrong polarization.

Table A2.11 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
RO7625	119154	090276	100176	B	EE	N	-	C	BI	D	C7	DG failed to start within time limit.
RO7626	119162	090776	100676	B	SFA	DD	-	C	OK,OC	A	C8	Fire pump actuation test associated with RDS not performed.
RO7627	119465	092776	102676	B	SA	Z	-	B	OK,OC	A	N	Expansi[illegible] joints at contain[illegible]ent penetrations not inspected as per tech specs.
RO7628	119464	100476	1026[illegible]	B	SFA	C	-	C	BU	G	C7	Water added to RDS battery and lowers its specific gravity.
RO76[illegible]9	119516	101476	102876	B	SF	Z	-	B	OK	D	N	Errors found in allowable leak rate limit calculations.
RO7630	119749	102176	112276	B	SFA	C	-	C	BU	G	C7	Water added to RDS battery and lowers its specific gravity.
RO7634	119750	102776	112376	B	SFA	-	C	C	OA	D	N	RDS system channel removed from service for maintenance.
RO7631	119751	102876	112376	B	EE	N	-	C	BI	D	C7	DG failed to start within time limit.
RO7632	120270	110476	120176	B	EE	N	-	C	BI	D	C7	DG failed to start within time limit.
RO7633	120271	110476	120176	B	SFA	C	-	C	BU	D	C7	RDS battery has low specific gravity.
RO7636	120680	111876	121776	B	EE	N	-	C	BI	D	C7	DG fails to start within time limit.
RO7637	120676	113076	123076	B	RB	-	C	C	OC	A	N	Liquid poison circuit test not performed.

Table A2.11 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
RO7638	120677	120276	123076	B	EE	N	-	C	BI	D	C7	DG fails to start within time limit.
RO7639	120679	120276	123076	B	SFA	C	-	C	BU	D	C7	RDS battery has low specific gravity.
RO7640	120678	120376	123076	B	HH	-	N	C	OK	A	N	Condensate radiation monitor flow inadequate due to surveillance procedures.
RO7642	120675	120976	122276	B	SFA	-	C	C	OK	A	C8	Insufficient knowledge of RDS actuation system violated tech specs.
RO7641	120674	120976	122276	B	SFA	-	-	-	OK	A	C8	RDS test procedures inadequate to cover tech specs.
RO7643	121053	120976	010777	B	SFA	C	-	C	BU	D	N	Low specific gravity in RDS battery "B."
RO7644	121052	122076	012077	B	EE	N	-	C	BI	B	N	DG fails timing test by 4 sec.
RO7645	121523	122776	012677	B	EE	N	-	C	BI	B	N	DG fails timing test. Modifications made to fuel governor lub oil supply.
RO7646	121524	122876	012677	B	EE	N	-	C	BD	D	C1	DG fails to start; the starter failed.

Table A2.12 Coding Sheet for Reportable Events at Big Rock Point - 1977

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
BC7701	121525	010377	012677	B	EE	N	-	C	BD	B	C1	DG fails to auto-start.
BC7702	122184	010477	020777	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS batteries.
BC7705	122186	010777	020877	B	EE	N	-	A	OE	-	N	DG out of service 8 hrs to modify fuel oil lub governor.
BC7703	122201	011877	021677	B	SD	FF	-	B	AA	D	N	Damper lock broken on stock fan. Air supply to damper worn through.
BC7706	122202	011977	021677	B	SFA	-	C	C	OE	-	N	RDS out twice for 24 hour period for maintenance.
BC7704	122187	012777	020877	B	SFA	-	T	B	OF	B	N	RDS switches not environmentally qualified.
BC7707	123020	021777	031777	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS battery cells. Tech specs change submitted.
BC7708	123798	022477	032377	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS battery cell.
BC7709	124103	031777	041477	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS battery cell.
BC7710	124901	032477	042177	B	EE	N	-	C	BI	D	N	Diesel fails start test by 0.8 sec.
BC7711	125210	033077	042877	B	SFA	G	-	B	AL	E	N	Loose connectors on uninterupted power supply.
BC7712	125339	042177	051677	B	SFA	C	-	C	BU	D	C7	Specific gravity of RDS low.

Table A2.12 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
RO7714	125032	042177	051777	B	-	-	-	C	OC	A	C8	Several tests missed due to poor 10 yr plan.
RO7713	125340	042177	051677	B	BB	-	N	B	BT	B	N	Operation of both air ejector radiation monitors degraded.
RO7717	125342	050377	051677	B	SFA	-	C	B	EG	D	N	One RDS channel power supply fails.
RO7715	125341	050377	051677	B	SFA	-	C	C	OC	A	N	RDS channels not tested after one failed.
RO7716	125180	050577	060377	B	CF	U,Z	-	B	OJ	A,E	N	Defective hose installed in post incident systems heat exchanger.
RO7718	125549	051877	061777	B	EE	N	-	C	BI	D	N	DG fails starting test by 1.3 sec.
RO7719	125550	052677	061777	B	EE	N	-	C	BI	D	N	DG fails starting test by 1.9 sec.
RO7720	125312	052777	060877	B	RC	R	-	B	OK	B	N	MAPLHGR limits nonconservative for single loop operators.
RO7721	126492	061677	071577	B	SFA	C	-	C	BU	D	C7	Specific gravity low on RDS battery cells.
RO7722	128318	072077	081977	B	EA	LL	-	C	AC	D	N	Bushing insulator on power transformer fails.
RO7723	128317	072877	081977	C	SFA	-	I	C	EH	D	N	Set point drift in steam drum level sensor.
RO7724	127981	080277	081677	C	CE	Z	-	C	AO	E	N	Poor weld in emergency condenser pipe.
RO7726	128945	080477	090277	C	IA	-	M	A	EH	D	N	Set point drift in RDS primary system pressure sensor (134062).

Table A2.12 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
RO7727	128946	080577	090277	C	EE	F	-	C	BB	E	C8	Transfer of DG power to "2B" bus fails (134063).
RO7733	128947	080677	090277	C	CF	U,Z	-	B	OJ	A	N	Defective hose installed in post accident heat exchanger (132710).
RO7734	128948	081077	090277	C	CG	Z	-	C	AO	E	N	Two Bid welds in demineralizer piping fail.
RO7735	129548	081277	090977	C	SB	-	E	A	EG	D	N	Containment spray flow transmitters fail.
RO7728	128222	081277	082577	C	SD	OO	-	C	AX	D	N	Cleanup sluice system valve leaks excessively.
RO7729	128221	081277	082577	C	SD	PP	-	C	AX	D	N	Rod drive check valves leak.
RO7730	128220	081377	082577	C	SD	Z,PP	-	C	OK	A	N	Design deficiency in CRD system could compromise containment.
RO7731	128223	081477	082577	C	CG	PP	-	C	AQ	D	N	Demineralized water line check valve leaks.
RO7738	130024	081677	092977	C	CH	PP	-	C	AQ,AT	D	N	Crud buildup results in feedwater check valve leakage.
RO7736	129829	082377	092377	C	RB	J	-	C	BW	D	N	3 CRDs withdraw too quickly.
RO7737	130025	082977	092977	C	SFD,AB	N,G	-	C	BD	D	C1	Diesel fire pump fails to start due to loose cables.
RO7725	129827	090477	091677	C	SD	OO	-	B	BB	D	N	Containment isolation valve fails to close (130907).

Table A2.12 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
BO7732	129828	090977	092377	C	SFD	-	-	-	HI	B	N	Study indicates some uncertainty in core spray distribution.
BO7739	130913	092977	102777	D	SFA	C	-	C	BU	D	C7	Specific gravity low on RDS battery cell.
BO7740	130908	100477	110177	D	SFD	-	N,T	C	EH	D	N	Six of eight core spray pressure switches set points drift.
BO7741	130997	102077	111877	D	EE	N	-	C	BI	D	C7	Diesel generator fails starting test.
BO7742	130998	102077	111877	D	SFA	C	-	C	BU	D	C7	Specific gravity low on RDS battery cell.
BO7743	131705	103077	112977	D	RB	-	T	B	OJ	H	N	CRD removed with reactor mode switch in run.
BO7744	130883	103177	110977	C	CX	OO	X	B	AY	H	C3	Reactor coolant backs up into plant heating system (2 uCi released to discharge cannal).
BO7745	131706	103177	112977	D	RB	OO	-	C	BI	D	N	CR withdrawal speed excessive.
BO7746	131791	111177	120977	B	RB	J	-	C	BD	D	N	CRD malfunctions.
BO7747	132949	111777	120977	B	SFD	LL	-	-	OK	A	C7	Defective procedure capable of reducing ECCS capability.
BO7751	133612	121577	011378	B	-	OO,F	-	C	OC	A	N	Surveillance schedule skipped.
BO7749	133610	121677	011378	B	RB	Z	-	B	AP	D	N	One drop/sec leak in weld between valve and pipe weld.
BO7750	133611	122277	011378	B	SFA	C	-	C	BU	D	C7	Specific gravity low on RDS battery cell.

Table A2.13 Coding Sheet for Reportable Events at Big Rock Point - 1978

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
RO7806	136471	010878	030778	B	SFA	-	C	B	EG	D	N	One of four RDS channels defective.
RO7801	134504	010978	020878	B	SFD,AB	N,G	-	C	BI	D	C1	Diesel fire pump fails to start within 20 sec.
RO7809	136472	011478	030778	B	SFA	-	C	B	EG	D	N	One of four RDS channels made inoperable for troubleshooting.
RO7812	136474	011778	030778	B	MA	HH	-	B	AM	B	N	Solenoid in rad waste system not qualified.
RO7802	134981	011978	021778	D	EC	C	-	C	BU	D	C7	Low specific gravity in RDS battery.
RO7803	134273	012078	020178	D	SD	OO	-	C	BC	D	N	Containment isolation valve leaks excessively.
RO7805	136476	020378	030178	B	MB	-	E	B	HB	G	N	Low flow in off-gas system.
RO7807	136470	020978	030778	B	EE	N	-	C	BF	D,B	N	Diesel generator trips after 25 min.
RO7808	135891	021578	021578	B	AB,SFA	-	T	A	OJ	H	S8	Both fire pumps unavailable with RDS out for maintenance.
RO7810	136477	021778	030178	B	CC	-	I	B	AM	B	N	Nonqualified flow switches.
RO7811	136473	021778	030778	B	RB	HH	-	B	AM	E	N	One scram pilot valve unfit for conditions.
RO7804	136475	022078	030178	B	EE	N	-	C	BI	D	C7	Diesel generator exceeds starting time by 15 seconds.
RO7813	137025	022378	032378	B	SD	-	I	B	AM	E	N	Marginal electrical circuitry for Big Rock.

Table A2.13 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
RO7815	136980	030978	032878	B	SFA	-	C	B	EG	D	N	One of four RDS channels out of service for troubleshooting.
RO7814	136981	031178	032878	B	SFA	-	C	B	EG	D	N	One of four RDS channels fails.
RO7817	137503	032078	041978	B	RB	-	T	A	BC	G	N	Control switch on CRD pilot valve incorrectly set.
RO7816	137502	032078	041978	B	SD	FF	-	B	AW	D	N	Containment leak rate exceeds limits.
RO7819	138237	040778	050278	D	IA	-	M	B	EH	D	N	One RPS vacuum sensor drifts slightly.
RO7818	138236	040778	050278	B	IA	-	I	B	EG	D	S2	Failure of two RPS channels during LOOP.
RO7820	138238	041178	050278	B	BB	OO	-	B	AQ	D	N	Crud causes off-gas flow to be low.
RO7821	138295	041578	051578	B	EA	LL	-	B	OE	-	N	Modification to substation.
RO7822	138296	041778	051578	B	EA	LL	-	B	-	H	C8	138 kv line deenergized, plant supplied load while 46 kv line was available.
RO7823	138821	050478	060178	B	AB	C	-	C	BU	D	C7	Low specific gravity in diesel fire pump starting batteries.
RO7824	139646	051278	061278	B	RB	-	M	C	EH	D	N	Drift in CRD accumulator level switch.
RO7825	139645	052578	061678	B	AB	C	-	C	BU	D	C7	Low specific gravity in diesel-fire pump starting batteries.
RO7826	141046	053178	063078	D	HH	JJ	-	B	BT	H	C6	Condensate storage tank level drops below tech specs limit after scram.

Table A2.13 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
RO7827	141048	053178	063078	D	RB	J	-	B	AG	H	N	Failure of a CR to withdraw beyond position 20.
LER7828	141049	060578	063078	B	CE	PP	-	B	AG	G	C8	Emergency condenser outlet valve inoperable.
LER7829	141050	060678	063078	B	CI	PP	-	B	AC	D	N	Excessive leakage of primary coolant.
RO7830	139900	071278	080778	B	SFA	-	C	B	EG	D	N	An RDS channel failed.
RO7831	140383	081078	082278	B	CG	Z	-	B	AO	B	N	Minor defect in reactor cleanup system piping.
RO7832	140350	081978	091578	B	HH	PP	-	B	AW	A	C3	Failed check valve allowed water from the fuel pool system to backflow into the demineralized water system.
RO7833	140701	082978	092778	B	FI	OO	-	C	AO	D	N	Reactor and fuel pit drain line valve leaks.
RO7834	140704	083178	092778	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS batteries.
RO7835	140211	090478	091278	B	SD	OO	-	C	AW	D	N	Containment valve leaks.
RO7836	140735	090578	100578	D	HH	JJ	-	B	BT	H	N	Condensate storage tank level drops below tech specs limit.
RO7837	140213	090678	091278	D	CD	OO	-	C	AC	D	N	An MSIV failed to close.
LER7838	141519	090978	100978	B	RB	J	-	B	BL	B	N	Reactor scrammed due to high CRD temperature.
LER7840	141524	091078	100978	D	EC	AA	-	B	AC	D	N	Containment relief valve invertor fuse blows.
LER7839	141522	091178	100978	D	IE	-	T	B	OJ	H	C8	CR removed with reactor not in shutdown mode.

Table A2.13 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER7841	141192	092278	100678	C	FD	L	-	B	AB	D	N	Refueling cask trip line fails.
RO7842	141844	092878	102678	D	RB	J	-	C	OK	A	N	CRD coupling test may be deficient.
LER7844	141453	101878	103178	B	CG	Z	-	B	AI	D	C8	Crack in nonisolatable 3" pipe (148063).
RO7845	141485	102078	110278	D	IB	G	-	B	AM	B	N	Nonlock qualified cables and connectors.
LER7840	141703	102578	111078	D	RB	J	-	C	BI	D	N	One CR exceeds scram limit.
LER7847	142288	103178	112978	B	RB	J	-	C	BL	D	N	One CRD temperature exceeds limit. See 153975.
RO7848	142209	110878	120678	B	CE	U	-	B	BL	A	N	Emergency condenser shell side temperature exceeds limit (153836).

Table A2.14 Coding Sheet for Reportable Events at Big Rock Point - 1979

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER7901	147305	020179	022679	B	SD	OO	-	B	BC	D	N	Containment ventilation valves out of adjustment.
LER7902	147304	020379	030279	C	HC	OO	-	B	AA	D	N	Condenser hotwell valve fails.
LER7903	147303	020479	030279	C	SD	PP	-	C	AW	D	N	Containment isolation valves leak excessively.
LER7904	147302	021979	030579	C	CE	Z	-	C	AV	E	N	Bad welds in emergency condenser inlet line.
LER7905	147301	022179	030579	C	RB	-	T	C	EE	D	C8	Seven of 32 CRD accumulator level switches fail.
LER7906	147300	022179	030579	C	CG	Z	-	C	AV	B	N	Cracks in reactor cleanup system piping (153974).
LER7910	148200	022179	032179	C	SHB	Z	-	C	AM	A	N	Backup hose for post incident heat exchanger to short.
LER7908	148201	022279	032179	C	EE	N	-	C	BI	D	C7	Diesel generator exceeds starting time.
LER7907	147299	022279	030579	C	CE	Z	-	C	AO	-	N	Weld does not meet present requirements.
LER7909	148199	022379	032179	C	CH	PP	-	C	AU	D	N	Feedwater check valve leaks.
LER7911	148337	030179	032179	C	RB	PP	-	C	AC	D	N	CRD pump check valve leaks.
LER7913	148339	030279	032779	C	CG	OO	-	C	AV	D	N	Reactor cleanup system sluice valves leak excessively.
LER7912	148338	030279	032779	C	SD	PP	-	C	AW	D	N	Containment isolation check valve leaks.

Table A2.14 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER7914	149434	031279	041179	C	EE	N	-	C	EC	D	C7	DG output voltage zero.
LER7916	149432	031379	041979	C	SFD	F	-	A	BC	G	N	Fire pump broken, damaged during maintenance.
LER7915	149433	031979	041979	C	SD	S	-	B	EE	B	N	Fuse blown on an inverter (also see LER79021).
LER7917	149977	041079	051079	C	SH	GG	-	C	AM	B	N	Inadequate snubbers.
LER7918	149976	041779	050279	C	CA	Q	-	C	AO	E	N	Leak between CRD housing and reactor vessel (153935).
LER7919	149731	041879	050279	B	RB	FF	-	C	AW	D	N	CRD flanges leak.
LER7920	150275	060979	062279	C	CB	Y	-	B	AD	D	S4	Recirculation diffusers break off.
LER7921	151824	061679	071379	C	SD	S	-	B	EE	B	N	Fuse blows on an inverter (also see LERs 7840 and 7915).
LER7922	151825	082279	090579	C	IA	-	I	B	EG	B	C4	Common mode problem with RPS and ECCS (153973).
LER7923	152017	091179	101079	C	SD	OO	-	C	AW	D	N	Reactor and fuel pit drain line valve leaks.
LER7924	152016	091379	101079	C	IB	-	T	C	EH	D	N	Minor drift in RDS switches.
LER7925	154266	103079	110979	D	SD	OO	-	B		D	N	Power supply to containment vent valves fails.
LER7926	154265	110179	120379	D	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS batteries.
LER7927	154264	111579	121179	B	CE	OO	-	B	AU	D	N	Emergency condenser outlet valve leaks (154558).
LER7928	154263	121379	122679	B	SD	OO	-	B	-	B	N	Containment isolation valve might not close given worst LOCA.

Table A2.14 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER7929	153498	121579	011580	B	SD	DD	-	A	OI	A	N	Both plant vent fans unavailable.

Table A2.15 Coding Sheet for Reportable Events at Big Rock Point - 1980

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER8001	154457	011480	021280	B	CE	OO	-	B	AW	C	N	Emergency condenser outlet valves leak through seal.
LER8003	154906	012380	022180	B	SFA	-	C	B	EG	D	N	One channel of RDS removed from service.
LER8002	154904	012480	022180	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS batteries.
LER8004	154459	020180	021280	B	CF	Z	-	B	AD	G	N	Control air tubing to auxiliary system cooling valve broken.
LER8007	155473	022480	031980	B	RB	DD	-	B	AP	D	N	A CRD pump failed.
LER8005	155482	030180	040280	B	IB	-	I	B	EH	D	N	RDS level sensor drifts.
LER8006	157053	040380	050180	B	IB	-	C	B	EH	D	N	RDS channel set point drift.
LER8009	156984	041580	051980	B	SD	FF	-	C	OC	A	N	Leak test not performed.
LER8010	157074	042380	052380	B	IB	-	I	B	EH	D	N	RDS level channel drift.
LER8011	158574	050180	053080	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS batteries.
LER8012	157076	050780	052380	B	IB	-	I	B	EH	D	N	Reactor level indicator drifts.
LER8013	156954	050980	052380	B	SD	OO	-	B	-	A	N	NRC dictated failure.
LER8014	158226	051280	061180	B	IB	-	I	B	EH	D	N	RDS channel drifts.
LER8015	158267	051580	061180	B	IB	-	I	B	EH	D	N	RDS channel drifts.
LER8016	158268	052780	061180	B	IB		I	B	EH	D	N	RDS channel drifts.
LER8017	158777	070380	080180	B	IB	-	I	B	EH	D	N	RDS test channel drifts.
LER8018	159088	071080	080480	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS batteries.

Table A2.15 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER8019	160291	071380	081280	B	SD	-	N	B	EE	D	N	Containment pressure sensor fails.
LER8021	159288	072980	082580	B	IB	-	I	B	EH	D	N	Set point drift in level transmitter.
LER8022	159256	080780	090580	B	SFA	C	-	C	BU	D	C7	Low specific gravity in RDS batteries.
LER8023	159293	081280	082680	B	SD	-	-	-	-	-	N	Procedures revised for small LOCA.
LER8024	159257	081480	091280	B	IB	-	I	B	EH	D	N	Set point drift in level transmitter.
LER8028	160071	090980	101080	B	IB	-	I	B	EH	D	N	Sensor channel D of RDS fails.
LER8030	160043	091980	101780	B	SD	OO	-	C	AW	D	N	Containment leak rate excessive.
LER8029	160072	091980	101080	B	SFA	C	-	B	BU	D	N	RDS battery fails to hold a charge.
LER8031	160171	092380	102080	B	IB	-	I	A	EH	G	N	RDS level switch set below limit.
LER8035	161469	102480	111980	B	CF	JJ	-	B	AO	A,D	N	Anion resin tank leaks.
LER8034	161674	110180	111980	B	CD	OO	-	B	AC	D	N	An MSIV failed to close on first attempt.
LER8036	161980	111880	121280	D	EE	N	-	C	BD	G	C1	DG fails to reach rated voltage.
LER8037	161982	111880	121280	D	EE	N	-	C	BE	D	C1	DG fails to run.
LER8038	161983	111880	121280	D	CH	PP	-	C	AU	D	N	Feedwater check valve leaks.
LER8039	162017	112780	122280	D	SD	OO	-	C	AW	D	N	Containment isolation valve leaks.

Table A2.15 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER8042	161911	120680	121880	D	RB	Z	-	C	AO	E	N	Crack in weld.
LER8044	170072	121080	021781	D	EE	N	-	C	AA,AP	D	N	A diesel generator voltage regulator circuit failed.
LER8045	163387	121080	010681	D	SD	PP	-	C	AI	C	N	A containment isolation check valve leak rate exceeded limits.
LER8046	162020	121180	020781	D	SFA	C	-	C	AQ	G	N	RDS battery inoperable due to corroded battery terminals.
LTB8043	161913	121280	122380	D	CG	Z	-	C	AB	D	N	Crack in reactor cleanup system pipe.
LER8047	162577	121780	011481	D	EE	N	-	C	EC	D	N	A diesel generators output voltage was too low.
LER8050	162425	122380	012081	D	EC	C	-	C	OC	A,G	N	Test interval for batteries exceeded time limit.
LER8049	163601	123080	012881	D	SF	-	I	C	EH	D	C8	A containment water level sensor read low (unconservative).

Table A2.16 Coding Sheet for Reportable Events at Big Rock Point - 1981

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER8101	166574	010281	012881	C	EFA	C	-	C	BU	D	C7	RDS battery cell specific gravity below limits.
LER8102	-	011281	012681	D	RB	OO	-	B	OA	B	N	A review discovered the possibility of over pressurizing the control rod drive water system.
LER8103	164372	012081	022681	D	SH	OO	-	B	AD	D	C7	Nitrogen bottle supply system depressurized due to broken valve.
LER8104	165219	031581	041381	B	MA	I	-	B	AE,AW	D	N	A chemical waste tank discharge piping leaked.
LER8105	165396	032181	041681	B	EE	N	-	C	BBD	D	N	Diesel generator failed to start within the time limit.
LER8106	166119	040781	050581	B	SD	-	R	B	BG	D	N	Containment vacuum relief control inoperable due to maintenance work.
LER8107	166068	041481	051281	B	EE	N	-	C	BD	D	N	A diesel generator failed to start within the time limit.
LER8108	166064	042081	051281	B	EE	N	-	C	BD	D	N	A diesel generator failed to start within the time limit.
LER8109	166547	050781	060581	B	SF	-	U	B	BL	D	N	The reactor vessel level sensing chamber had a high temperature.
LER8110	166842	051681	061181	B	SD	RH,OO	-	C	BI	D	N	Containment isolation closure time was too long.
LER8111	166851	061281	070981	B	SD	OO	-	C	OA	G	N	Vacuum relief for the containment building exhaust loop inoperable.

Table A2.16 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER8112	167004	061581	070981	B	SD	HH,OO	-	C	BI	B	N	Containment isolation valve response time exceeds limit.
LER8113	167175	061781	071681	B	SFA	-	C	B	OA	D	N	RDS inoperable due to failed power supply inverter.
LER8114	168499	072881	082681	B	BA	G	-	A	OE	D	N	Both emergency radiation monitors inoperable due to maintenance repair required.
LER8115	168924	081381	091181	B	AB	OO	-	C	BC	H	C1	A diesel fire pump auto start pressure sensor was valved out.
LER8116	168490	081381	082681	B	SA	OO	-	A	OA	B	N	Potential for containment pressurization existed due to leaking instrument air.
LER8117	168922	081581	091181	B	SFA	C	-	B	BS	H	C7	Battery cell for RDS overfilled, specific gravity within limits.
LER8118	174701	082281	091881	B	MB	HH,OO	-	A	AA	D	N	Off gas system inoperable for sampling system repair.
LER8119	174660	083181	092581	B	EC	C	-	C	BU	D	C7	A battery cell leaked and had a low specific gravity.
LER8120	169217	090681	100581	B	MA	Z	-	B	AR,AW	D	N	A liquid radwaste system piping leaked.
LER8121	170006	091581	101381	B	SFA	C	-	C	BU	D	C7	The RDS specific battery had a low specific gravity.
LER8122	169229	091781	093081	B	SFA	F	-	B	OK	H	C8	Two RDS loops became inoperable when the wrong circuit breaker was opened.

Table A2.16 (continued)

NUMBER	NSIC ACCESSION NUMBER	EVENT DATE	REPORT DATE	PLANT STATUS	SYSTEM	EQUIPMENT	INSTRUMENT	COMPONENT STATUS	ABNORMAL CONDITION	CAUSE	SIGNIFICANCE CATEGORY	COMMENT
LER8123	169230	091981	100181	B	SD	OO	-	C	AA	D	N	Two containment isolation valves leaked.
LER8124	170002	093081	101381	B	WB	U	-	C	AR,AW	D	N	A containment pipeway air cooler leaked.
LER8125	170[illegible]34	101481	111081	B	MA	Z	-	B	AR,AW	D	N	A condensate demineralizer system drain line leaked.
LER8126	171583	120781	010682	B	MA	DD	-	B	AR,AW	D	C7	Pump casing spills radioactive water.
LER8127	172025	123081	012982	B	WC	-	-	-	OD	D	C3	Demineralized water storage found contaminated with iodine.

APPENDIX G

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D. Vreeland	Lawrence Livermore National Laboratory	VI-2.D	December 1981
		VI-3	December 1981
D. Wesley	Lawrence Livermore National Laboratory	III-6	December 1980
B. Atefi	Scientific Applications, Inc.	PRA	March 1983
J. McDonald	Texas Tech University	II-2.A	May 1980
J. Scherrer	Westec	II-3.A	April 1982
		II-3.B	April 1982
		II-3.B.1	April 1982
		II-3.C	April 1982

APPENDIX H

LICENSEE'S LETTER ON EXPANDED SEP

Consumers Power Company

General Offices: 1945 West Parnall Road, Jackson, MI 49201 • (517) 788-0550

June 1, 1983

Dennis M Crutchfield, Chief
Operating Reactors Branch No 5
Nuclear Reactor Regulation
US Nuclear Regulatory Commission
Washington, DC 20555

DOCKET 50-155 - LICENSE DPR-6 - BIG ROCK POINT PLANT - INTEGRATED ASSESSMENT OF OPEN ISSUES AND SCHEDULE FOR ISSUE RESOLUTION (INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND GENERIC LETTER 82-33 ISSUES)

Consumers Power Company committed in a letter dated March 18, 1983 to conduct a comprehensive integrated assessment of all open issues (both regulatory and non-regulatory) for the Big Rock Point Plant and to develop a living schedule for resolution of the important issues. In the opinion of Consumers Power Company, the integrated assessment and scheduling approach to the resolution of issues is essential for safe and economical future operation of the plant. Such an approach provides an effective use of finite resources to resolve the most significant issues as expeditiously as possible.

The purpose of this letter is to describe the integrated assessment and scheduling approach taken by Consumers Power Company and to submit the resulting schedule for issue resolution. In addition, this letter serves to document Consumers Power Company response to the recent 10CFR50.49(g) rulemaking regarding environmental equipment qualification and to Generic Letter No. 82-33 entitled "Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability".

INTEGRATED ASSESSMENT OF ISSUES

Purpose

In an effort to ensure safe and economical future operation of Big Rock Point Plant, finite company resources must be directed first towards those issues for which resolution offers the greatest return on the investment. The purpose for the Integrated Assessment (IA) was to rank the issues relative to one another based on perceived magnitudes of reduction in risk or increase in plant availability attributable to their resolutions. Plant-specific probabilistic risk assessment (PRA) cost/benefit data, in terms of dollars per

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man-Rem eliminated, was used for many of the issues to aid in the evaluation of return associated with their proposed resolutions. In general, the living schedule for issue resolution was constructed by assigning resources first to those resolutions featuring the greatest return. As a result, issues featuring resolutions which offer little return were scheduled to be performed at a later date. Please note that many of the issue resolutions consist of performing evaluations to determine the necessity for implementing future plant modifications. The TRG will assess the results of such evaluations and may re-rank the issue accordingly.

Sources of Issues

The issues evaluated and incorporated into the living schedule were derived from a list of outstanding regulatory issues and from the plant-initated projects list. Those issues for which resolutions are to be completed prior to the end of the current refueling outage were precluded from the living schedule.

TECHNICAL REVIEW GROUP COMPOSITION AND STRATEGY

A Technical Review Group (TRG) was formed to assess the issues and their resolutions. In order to adequately assess the safety and/or availability implications associated with each of the issues and their resolutions, the TRG was comprised of individuals who are most familiar with plant design, operation, margins of safety and licensing. Members of the TRG consisted of the plant Operations and Maintenance Superintendent, the plant Technical Superintendent, the plant Technical Engineer, the Continuing Risk Management Program Manager, an engineer representing the corporate Radiological Services Department and an engineer representing the corporate Nuclear Licensing Department. The TRG performed the IA by implementing the following strategy: 1.) developing its own issue assessment criteria and methodology, 2.) evaluating each issue resolution against such criteria utilizing the developed methodology and 3.) developing the ranked list of issue resolutions which was used as the input to the scheduling process.

INTEGRATED ASSESSMENT CRITERIA AND METHODOLOGY

The IA criteria and methodology is presented as Attachment 1 to this letter. The TRG utilized sound engineering judgment, as supplemented by PRA cost/benefit data where applicable, to assess each issue resolution against each of the four assessment criteria. It should be noted that a proposal for resolution has not yet been developed for approximately ten percent of the open issues. It is for such issues that the TRG evaluated the safety and/or availability implications associated with the issue initiator's concern instead of the resolution of that concern.

During the assessment of each issue, the TRG identified: 1.) the issue initiator (eg, the plant or the NRC), 2.) the issue initiator's concern and 3.) the proposed resolution of the concern. The TRG then utilized the assessment criteria to evaluate either the return associated with issue's

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proposed resolution or, in the case of approximately ten percent of the issues, the safety and/or availability implications associated with the issue initiator's concern. Each TRG member's evaluation of each issue was then documented on a tally sheet. As shown in Attachment 1, four categories of significance (ie; high, medium, low or none) were assigned to each criterion.

The resulting ranked list of issues is shown in Attachment 2. The list has been subdivided into categories which represent the level of significance assigned to each issue by the TRG as a result of evaluating the issue against the assessment criteria (ie; safe shutdown, radionuclide release, plant availability or personnel safety). A set of scope statements is provided in Attachment 3 which serves to document TRG discussion during the IA meetings and to provide justification for the relative ranking of each issue. Specifically, the scope statements serve to: 1.) identify the issue initiator, 2.) describe the initiator's concern, 3.) identify the proposed resolution of that concern, 4.) identify alternate means of resolution and, 5.) provide the basis for the selection of the preferred alternative.

ELIMINATION OF RANKED ISSUES FROM THE SCHEDULE

Although the final ranked list includes all of the issues evaluated, many of the resolutions were not scheduled. Issues that were eliminated from the scheduling process were those ranked number 46 through 64, for which no safety or availability implications exist. In addition, four issues in the low significance category were eliminated (ie; issues ranked as numbers 34, 36, 37 and 41). Many of these issues are NRC-initiated and, as a result, Consumers Power Company requests relief from such issues. Attachment 4 identifies the NRC-initiated issues that are not scheduled and provides reference to either docketed submittals or to future submittals which will provide justification for relief. It is the opinion of Consumers Power Company that the referenced justificaton, along with the level of safety significance assigned to these issues by the TRG, fully substantitates our position that relief should be provided.

SCHEDULE FOR ISSUE RESOLUTION

Development and Maintenance

The input for Consumers Power Company's living schedule for issue resolution was the list of issues as ranked by the TRG. The resolutions for the ranked issues were then formally scoped, planned, estimated, and then scheduled. To achieve scope, schedule and cost integration, a top-down then bottom-up scoping-subscoping process was used. In this process the total scope was represented as the top element (issue) of the work breakdown structure with discrete sub-issues and activities represented as sub-elements. After identifying the total scope of work currently known for the living schedule, each performing organization was assigned responsibility for determining resolution work scope and individuals were specifically designated to provide estimates of required resources as input to the detailed scoping, planning, estimating and scheduling effort. Each performing organization broke down the workscope to a level that was manageable and reconcilable between departments assigned not only to work on a single issue but also to work between issues.

Following the breakdown of the workscope, all issues were broken up into work tasks by the responsible department and were then sequenced based on their logical inter-relationships. The work tasks were then integrated within issues and between issues and the necessary logic adjustments were made to yield an integrated living schedule.

Once the final logic network was established, critical resources were levelled (manpower, money) and durations/logic changes were reviewed to create a feasible schedule. Based on completing high priority (ie, low rank number) issues first, lower priority issues were scheduled based on remaining resource availability.

It is important to note that the schedule for completing the remaining work for each issue contained in the living schedule has been established through assessment of the scope of work associated with each issue. Changes to the scope of any issue or changes in the number of issues remaining may modify the living schedule.

Attachment 5 provides the Consumers Power Company living schedule for issue resolution. Attachment 6 provides a milestone summary table illustrating the key events and interfaces. Where anticipated completion dates for milestone activities were identifiable at the time of this submittal, they are so noted on the living schedule (see legend on living schedule for symbol definition). For those milestone activities for which we could not determine a completion date, we have shown a date by which a completion date will be determined. Milestones for which anticipated completion dates of dates for determination of anticipated completion dates are not known at the time of this submittal, are so designated in the schedule.

Several general assumptions apply to the development of the living schedule and are described as follows:

1. The issues were scheduled based upon their rank position and their inter-relationships with other issues. If the rank position of the issue changes, the schedule commitments that are illustrated on Attachment 5 may change.

2. Future definitive schedule commitments for those issues whose scope and/or findings are not yet known, cannot be submitted at this time. However, a date by which a commitment date will be determined has been supplied.

3. The Consumers Power Company living schedule is based on specific work scopes for each issue. Any changes to issue work scope may result in changes to the living schedule. Work scope and resulting plans determine what resources and durations the schedule illustrates. Should a change occur in work scope for these issues, either during negotiation with the

NRC or during the implementation of issue resolution, the potential exists for a change to occur in the living schedule.

4. The living schedule includes good faith efforts by the company that are either in progress or complete to meet issue requirements. As the NRC is aware, Consumers Power Company has initiated work on many of the issues identified in the ranked list and in the living schedule.

5. Stated schedule and future company commitment dates downstream of NRC activities are predicated on the NRC supporting the living schedule.

6. Development of the schedule assumed as an annual constraint that portion of the total Big Rock Point Plant operating budget which can be assigned to the resolution of non-repetitive type projects. The schedule was also influenced by a critical manpower resource constraint. Many of the scheduled resolutions will be performed by a limited number of experienced personnel. This is a realistic constraint since the company cannot acquire, over the short run, additional resources with necessary expertise without contracting the very costly service of organizations outside of the company.

ON-GOING EFFORT TO MAINTAIN THE LIVING SCHEDULE

It is Consumers Power Company intention to maintain a living schedule for the resolution of non-repetitive type issues. In doing so, Consumers Power Company plans to update the living schedule on at least a monthly basis and to revise the schedule to maintain it as current as reasonably achievable. It is currently envisioned that monthly status reporting by the assigned responsible issue managers to our Nuclear Planning and Administration Department will be the vehicle by which the schedule is periodically updated to reflect the current status of issue resolution.

Regarding the scheduling of new issues (both regulatory and non-regulatory) it is expected that such issues will undergo an assessment and scheduling effort similar to that employed for the issues as described in this letter. It is currently envisioned that the TRG will convene on a quarterly basis to evaluate the safety and/or availability significance of the proposed resolutions to new issues and to rank the issues appropriately alongside other issues of similar significance. The issue resolutions would then be scoped and broken down as described above so that required resources can be determined and effectively utilized.

Consumers Power Company will continue monitoring the progress of the living schedule and provide the NRC with semi-annual status updates commencing six months following receipt of the NRC's draft Integrated Plant Safety Assessment Report.

It is our opinion that such an on-going effort will provide both Consumers Power Company and the NRC with a flexible and reliable means to help manage and control the issues that confront Big Rock Point.

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ENVIRONMENTAL EQUIPMENT QUALIFICATION

The NRC, in a letter dated April 26, 1983, transmitted the Safety Evaluation Report (SER) and the Technical Evaluation Report (TER) for the Environmental Qualification of Safety-Related Electrical Equipment for the Big Rock Point Plant. The NRC requested in the SER that Consumers Power Company provide by June 1, 1983 our plans for qualification or replacement of the equipment in NRC Categories I.B, II.A and IV, in addition to the justification for continued operation (JCO) required in the near term, and the schedule for accomplishing the proposed corrective actions in accordance with the Equipment Qualification rule (10CFR50.49(g)). The NRC's April 26, 1983 letter also requested reaffirmation of the JCO and within thirty (30) days of receipt of the letter, submittal of information for items in NRC Categories I.B, II.A and IV for which JCO was not previously submitted. Consumers Power Company responded to the latter request in our submittal dated May 31, 1983. This section responds to the remaining NRC requests.

The Big Rock Point Environmental Equipment Qualification (EEQ) program plan consists of three distinct activities: 1.) Failure Modes and Effects Analysis (FMEA), 2.) dispositon of equipment qualification deficiencies as noted in the TER regarding parameters other than aging (ie; pressure, temperature, radiation, etc) and 3.) disposition of equipment qualification deficiences as noted in the TER regarding aging. The FMEA will be performed for certain electrical equipment to assess the need for further qualification. The FMEA will consist of an evaluation to determine: 1.) if the safety function is performed prior to environmental conditions becoming so harsh that equipment failure may result and 2.) if after the equipment has performed its initial safety-related function, subsequent failure of the equipment will not: negate its initial safety function, affect other equipment or functions or mislead the operator. If the evaluation shows that the above conditions are true, no additional qualification efforts are necessary. It is currently expected that the results of the FMEA will be submitted to the NRC by September 30, 1983.

Regarding equipment qualification deficiencies involving parameters other than aging, existing qualification argument and JCOs will be reviewed for adequacy and will be supplemented with additional supporting information if available. For equipment noted as being deficient, qualification argument will be reviewed and strengthened in an effort to substantiate our opinion that the equipment will not fail and will operate as intended during and after the accident. Should such argument not be available, JCO will be to reviewed and modified as necessary to provide a systems level evaluation of the ability of the plant to mitigate the effects of an accident and safely shut down even if such equipment fails. Consumers Power Company currently expects to submit to the NRC by February 28, 1984 revised qualification argument or JCO for each piece of equipment noted in the TER as being deficient in qualification for parameters other than aging. Regarding the modification of safety-related equipment during the current refueling outage, Consumers Power Company plans to submit to the NRC by September 30, 1983 the results of a review of the existing qualification argument and JCO applicable to such equipment.

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Regarding equipment qualification deficiencies involving aging, it should be noted that Consumers Power Company has outlined an extensive aging program in our April 30, 1982 submittal. The aging program is currently being developed; however, due to the significant amount of time required for data collection from vendors, performance of activation energy analysis and receipt of manufacturer recommendations regarding component replacement, development of the program is not yet complete. When completed, the aging program will include as a minimum: 1.) the identification of age-sensitive components, 2.) the determination of the qualified life for such components and 3.) the timely replacement of such components. Consumers Power Company plans to complete program development and implement the replacement program by June 30, 1984.

The recent 10CFR50.49 rulemaking also requires that Consumers Power Company submit a list of electrical equipment important to safety. In response to the request, Consumers Power Company informs the NRC that since we have not made any modifications to the plant affecting the EEQ list since our March 15, 1982 submittal, no new equipment has been added to the original Equipment Qualification Report submitted on October 31, 1980 as updated by our submittals dated January 30, 1981, September 3, 1981 and March 15, 1982. Consumers Power Company will continue to update our equipment list as a result of the reviews described above and future modifications and will accordingly submit revised enclosures to the Big Rock Point Equipment Qualification Report when appropriate.

It is the opinion of Consumers Power Company that the above description of our plans to address the EEQ issue with the accompanying scheduled commitment dates represent a complete response to the NRC's April 26, 1983 SER. The above described plan meets the intent of 10CFR50.49 requirements and replaces all previous EEQ commitments.

SUPPLEMENT 1 TO NUREG-0737 ISSUES

Generic Letter 82-33 "Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability" transmits as guidance the fundamental requirements concerning the: 1.) installation of a Safety Parameter Display System (SPDS), 2.) Performance of a Detailed Control Room Design Review (DCRDR), 3.) the application of Regulatory Guide 1.97 to Emergency Response Facilities (ERFs), 4.) the upgrade of Emergency Operating Procedures (EOPs), and 5.) the establishment of ERFs. In addition to transmitting the above fundamental requirements, the letter requests that Consumers Power Company submit a proposed schedule for completing the aforementioned activities. The letter recommends that plant-specific schedules be established which take into account the unique status of the plant and that such schedules be submitted to the NRC.

As shown in Attachment 5 (the living schedule) the performance of the DCRDR and the EOPs upgrade have both been scheduled. Attachment 6 provides milestone dates for these two activities. It should be noted that the results of the DCRDR will be used to substantiate whether or not the installation of a

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SPDS is justified for Big Rock Point Plant. It is Consumers Power Company opinion that due to the very small size of the plant control room and the fact that existing safety indications and controls are located within close proximity to each other, utilization of an effective DCRDR to determine the necessity of a SPDS is a prudent course of action.

The application of Regulatory Guide 1.97 to ERFs was not ranked or scheduled. The basis for excluding this activity from the living schedule is provided in two documents. The NRC revised safety evaluation report regarding SEP Topic VII.3 "Systems Required for Safe Shutdown", which was transmitted to Consumers Power Company on December 17, 1982 states: "the staff has concluded that the present design is an acceptable alternative to current licensing guidelines until Regulatory Guide 1.97 Revision 3 backfit decisions are made". In addition, Consumers Power Company submittal dated June 1, 1981 states: 1.) "the PRA indicates that the risk to the public is not affected by the use of the Shift Supervisor's office and hallway adjacent to control room as the TSC or the use of control room instruments by direct observation from the TSC", 2.) "this requirement (of the TSC data system meeting the set of Type A, B, C, D and E variables per Regulatory Guide 1.97, Rev. 2) is not met, however, the control room data available is sufficient information available to the TSC staff to perform the analytical tasks needed in post-accident analysis", and 3.) "the EOF is not provided with data system equipment".

The establishment of ERFs was also neither ranked nor scheduled. The aforementioned Consumers Power Company June 1, 1981 submittal provides the NRC with facility design descriptions for the ERFs and provides our conclusion that the current ERFs for Big Rock Point are adequate for the protection of the public based on results of the PRA.

EXEMPTIONS FROM CURRENT REQUIREMENTS

Consumers Power Company is presently assessing the impact that our living schedule for the resolution of open issues has on our commitments which have been made in response to NRC recommendations and requirements. Upon completion of our review, Consumers Power Company will submit the necessary exemption requests to the NRC to ensure that we can implement and maintain our living schedule for issue resolution without failing to meet our regulatory obligations.

Kerry A Toner (Signed)

Kerry A Toner
Senior Licensing Engineer

CC Administrator, Region III, USNRC
NRC Resident Inspector-Big Rock Point

Attachments

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Consumers Power Company

Big Rock Point Plant

Docket 50-155 - License DPR-6

INTEGRATED ASSESSMENT OF OPEN ISSUES
AND SCHEDULE FOR ISSUE RESOLUTION
(INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND
GENERIC LETTER 82-33 ISSUES)

At the request of the Commission and pursuant to the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974, as amended, and the Commission's Rules and Regulations thereunder, Consumers Power Company submits our response to Generic Letter 82-33 dated December 17, 1982, entitled "Requirements for Emergency Response Capability". Consumers Power Company response is dated June 1, 1983.

CONSUMERS POWER COMPANY

BY R B DeWitt (Signed)

R B DeWitt, Vice President
Nuclear Operations

Sworn and subscribed to before me this 1st day of June 1983.

Sherry L Durfey (Signed)

Sherry L Durfey, Notary Public
Jackson County, Michigan

(SEAL)

My commission expires November 5, 1986.

MI0583-0027A-NL02

Consumers Power Company
Big Rock Point Plant
Docket 50-155

INTEGRATED ASSESSMENT OF OPEN ISSUES AND SCHEDULE FOR ISSUE RESOLUTION (INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND GENERIC LETTER 82-33 ISSUES)

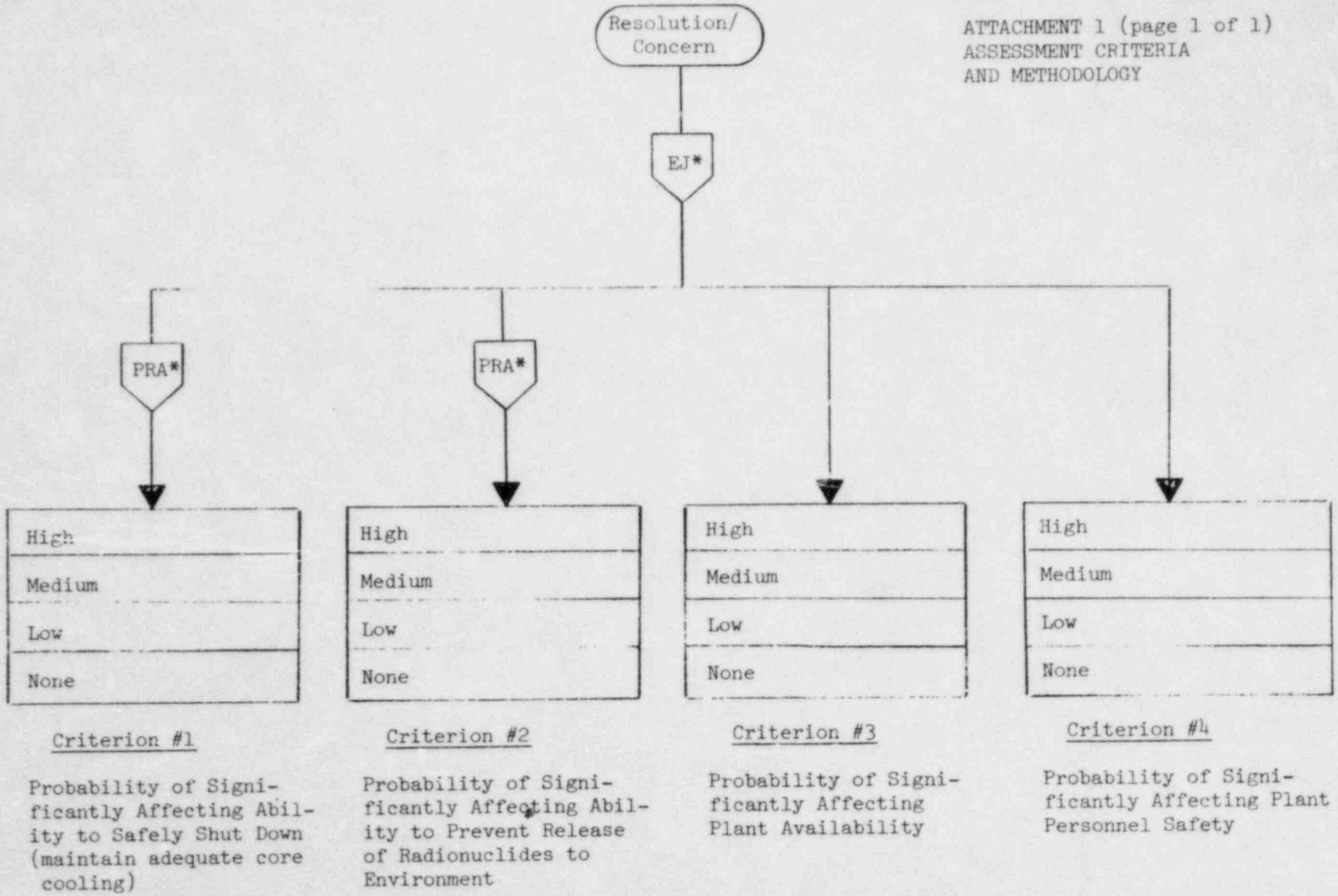
June 1, 1983

Attachment No. 1

Assessment Criteria and Methodology

1 page

ATTACHMENT 1 (page 1 of 1)
ASSESSMENT CRITERIA
AND METHODOLOGY



* EJ = Engineering Judgement

PRA = Probabilistic Risk Assessment Data

Consumers Power Company
Big Rock Point Plant
Docket 50-155

INTEGRATED ASSESSMENT OF OPEN ISSUES AND SCHEDULE FOR ISSUE RESOLUTION (INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND GENERIC LETTER 82-33 ISSUES)

June 1, 1983

Attachment No. 2

Technical Review Group
Ranked List of Issues

3 pages

BIG ROCK POINT PLANT
TECHNICAL REVIEW GROUP
RANKED LIST OF ISSUES

Ranking	Issue Description	Issue #	Significance*
1	RDS Depressurization Valve Pilot Valve Leakage	82	high
2	Alternate Shutdown System (Panel & Procedure) - Appendix R	75A	
3	Turbine Bypass Valve EHC System		
4	Environmental Equipment Qualification	36	
5	Secondary System Instabilities	16	
6	Seismic Design Considerations - SEP Topic III-6	14	
7	Upgrade Emergency Operating Procedures-NUREG 0737	32	
8	Plant Shielding - NUREG 0737	54	
9	High Pressure Recycle	18	
10	Containment Isolation - On Line Testing of MSIV-SEP Topic VI-4	50A2	
11	Control Room Habitability - NUREG 0737	57	
			high / medium
12	Single Channel Reset	8	
13	Containment Overpressurization	85	
14	Organic Materials - SEP Topic VI-1	22A	
15	Clean-up Demin. Pump Replacement Investigation	48	
16	Containment ILRT	64	
17	Stack Gas Monitoring	4	
18	PCS Isolation	17	
19	Scram Dump Tank Valves - Lack of Redundancy	84	
20	Acid Line Extension	2	
21	Facility Modification on Annex & Warehouse	72	
22	Investigate Incore Availability Problem	77	
23	Fire Protection-Associated Circuits-Appendix R	75C	
24	Control Room Design Review - NUREG 0737	5	
25	Acid and Caustic Tank Problems	69	
26	Wind and Tornado Loadings & Tornado Missiles - SEP Topic III-2 & III-4.A	25	
27	Replace Tube Bundle in Htg & Clg Heat Exchanger	1	
			medium / low
28	Ventilation For Panel C-52	10	
29	Verification of BS&B Valve Data	44	
30	Containment Purging/Venting	63	
31	Containment Isolation - Leak Test of Existing Check Valves - SEP Topic VI-4	50B	
32	Bypass of Motor Operated Valve Thermal Overloads - SEP Topic III-10.A	86	

ATTACHMENT 2

Ranking	Issue Description	Issue #	Significance*
33	Containment High Range Monitor - NUREG 0737	76	
34	Recirculation Pump Trip	21	
35	HELB - SEP Topic III-5.A	52	
36	Scram Dump Tank Level Instrumentation Gen Letter 81-18	7	
37	Performance of BWR Safety Valves	80	
38	FHSR Update Study	35B	
39	Full Stroke Testing of RDS Depressurization Valves	83	
40	Containment Isolation - Add Control Circuit to Treated Waste Valve - SEP Topic VI-4	50D	
41	Instrumentation to Detect Inadequate Core Cooling	20	
42	Control of Heavy Loads	73	
43	BOP QA Program	23	
44	Emg DG Panel Ventilation	70	
45	Reactor Cooling Water Pressure Study	9	low
			none
46	Radwaste Monitor Flush Timer	66	
47	Flooding Potential & Capability to Cope - SEP Topics II-3.B & II-3.B.1	37	
48	Safety Related Water Supply - SEP Topic II-3.C	38	
49	Purity of Primary Coolant - SEP Topic V-12	13	
50	Effects of High Water Level - SEP Topic III-3.A	39	
51	Containment Isolation - Isolation Valves in Htg, Clg or Svc Water - SEP Topic VI-4	50C	
52	Definition of Operability	31	
53	Control Room Air Conditioning	34	
54	Containment Isolation - Air Lock Testing - SEP Topic VI-4	50E	
55	Containment Isolation - Hand Iso of Instr Lines SEP Topic VI-4	50F	
56	Revise Drawings	62	
57	Post Accident Chemistry - SEP Topic V-12	22B	
58	Reactor Coolant System High Point Vents - NUREG 0737	74	
59	Radiological Effluent Technical Specifications	30	
60	Hydrogen Monitoring - NUREG 0737	19	
61	Containment Isolation-Pneumatic Test of MSIV - SEP VI-4	50G	
62	Design Codes. Criteria and Load Combinations - SEP Topic III-7.B	51	
63	Position Indication of PORV	81	
64	Fire Protection-of Offsite Power (Radiant Energy Shield) - Appendix R	75B	none

* The issue is considered by the Technical Review Group to be of high, medium, low or no significance when evaluated against the assessment criteria (ie, safe shutdown, radionuclide release, availability or personnel safety).

Consumers Power Company
Big Rock Point Plant
Docket 50-155

INTEGRATED ASSESSMENT OF OPEN ISSUES AND SCHEDULE FOR ISSUE RESOLUTION (INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND GENERIC LETTER 82-33 ISSUES)

June 1, 1983

Attachment No. 3

Issue Scope Statements

69 pages

ATTACHMENT 3
(69 pages)

Issue Scope Statements

Ranked Position	Issue No	Issue Identification	Issue Scope
1	82	RDS Depressurization Valve Pilot Valve Leakage	The plant staff recognizes a need to reduce the incidence of pilot valve leakage in the 3-stage depressurization valves in the Reactor Depressurizing System (RDS). Undetected leakage can lead to primary blowdown through a 1-½ inch bypass line which can be terminated only by remote manual operation of a bypass isolation valve. Operation in an isolation mode following such leakage (one valve for majority of each operating cycle) does not eliminate the potential for inadvertent blowdown since other challenges are imposed during the 90-day tests on other RDS components during power operation. Evaluation to determine reduction of risk was proposed. It was the opinion of the Technical Review Group (TRG) that this issue carries safe shutdown, radionuclide release, personnel safety and plant availability implications. The TRG ranked the aforementioned evaluation. Note: Preliminary PRA data indicate a failure rate causing blowdown of 6.7×10^{-3}/yr.

Ranked Position	Issue No	Issue Identification	Issue Scope
2	75A	Alternate Shutdown System and Procedural Development - Appendix R	This issue, as initiated by the NRC per 10CFR 50, Appendix R, concerns the ability to safely shutdown the reactor and to subsequently prevent radionuclide release during conditions of fire in either the control room, the electrical equipment room, the exterior cable penetration room or the containment electrical penetration area. Such ability is to be attained through the use of an alternate shutdown system, located in areas isolated from those mentioned above, to control Primary Coolant System (PCS) parameters. The present resolution is to install an alternate shutdown control station (panel) and power supply within the immediate vicinity of the core spray room. The station would feature certain PCS instrumentation and controls which are used to valve in the emergency condenser for purposes of reactor cooldown. The resolution also includes the development of suitable operating procedures by which the alternate shutdown station would be used to shut down the reactor. This issue was resolution-ranked by the Technical Review Group.

Ranked Position	Issue No	Issue Identification	Issue Scope
3	11	Turbine Bypass Valve EHC System	The plant staff recognizes a need to improve the reliability of the Turbine Bypass Valve Electro-Hydraulic Control (EHC) System. The system is unreliable in that the valve has on occasion not operated properly during start-up (the valve cycles open and closed) and during power operation (the valve fails to open or inadvertently opens). This issue has safe shutdown, radionuclide release and plant availability implications. During power operation, failure of the valve to open results in a loss of the full-power main heat sink for the Primary Coolant System and necessitates use of the emergency condenser to cool the reactor. Failure to open can also result in a needless plant trip during a load rejection or a loss of offsite power transient. Should the valve inadvertently open during operation, a plant trip may result. During start-up, valve cycling or spurious operation can establish transients which result in plant trip. The recommended resolution is to perform a study to identify the frequency and type of misoperation and possibly attribute the misoperation to some specific portion of the EHC System prior to contacting the manufacturer. The resolution of this issue was ranked by the Technical Review Group.

Ranked Position	Issue No	Issue Identification	Issue Scope
4	36	Electrical Equipment Qualification	This issue, as promulgated by the recent 10CFR 50.49 rulemaking, concerns the ability of electrical equipment important to safety to reliably operate in harsh environments to safely shut down the plant during accident conditions. Presently, the NRC requires that all such equipment be duly qualified and documented as such. Consumers Power Company has submitted to the NRC the list of electrical equipment important to safety and has provided justification for its qualification. The NRC responded to our submittal by indicating that a number of qualification discrepancies exist regarding certain equipment. The Technical Review Group (TRG) evaluated and ranked the proposed resolution to the issue. The resolution proposes to: 1.) perform failure modes and effects analysis (FMEA) on equipment where noted deficiencies exist regarding variables other than aging (ie; pressure, temperature, radiation, etc.), 2.) utilize qualification argument and justifications for continued operation for equipment where FMEA is not successful and 3.) develop an adequate preventive maintenance program for equipment where noted deficiences exist regarding aging. In the opinion of the TRG, the aforementioned proposed resolution is more justifiable from a cost/benefit standpoint (ie, reduction in risk per unit investment) for Big Rock Point than are the alternate resolutions of extensive additional qualification testing and analysis or wholesale replacement of equipment. It is the opinion of the TRG that the proposed resolution can achieve a satisfactory margin of safety for an expenditure orders of magnitude less than that required for the other alternatives.

Ranked Position	Issue No	Issue Identification	Issue Scope
5	16	Secondary System Instabilities	The plant staff recognizes the need to ensure that proper Primary Coolant System (PCS) makeup will occur following a load rejection. Following a load rejection, the PCS will blow down through the turbine bypass valve to the condenser hot well. As a result, the hot well levels will swell causing a signal to open the reject valve. When the reject valve opens, a significant portion of the condensate pump discharge is diverted from the suction of the reactor feed pumps to the condensate storage tank. The loss of feed pump suction results in a feed pump trip and thus the loss of PCS makeup during the blowdown condition. This issue has both safe shutdown and availability implications since a loss of PCS inventory could result in a low reactor water level condition which subsequently results in automatic reactor trip. The proposed resolution is to modify the existing reject valve control circuitry such that valve opening does not occur during the conditions described above. PRA has revealed that the proposed modification reduces the core damage probability from 6.2×10^{-5} to 2.5×10^{-5}/yr. PRA has shown that the cost/benefit ratio of the proposed modification is $960/man-Rem. This issue was resolution-ranked by the Technical Review Group.

Ranked Position	Issue No	Issue Identification	Issue Scope
6	14	Seismic Design Considerations - SEP Topic III-6	This issue concerns the ability of reactor shutdown systems to withstand a seismic disturbance such that they can be depended on to safely shut down the reactor. The NRC is concerned that older plants may not possess the necessary seismic capacity since initial design requirements for such plants were significantly less stringent than today's requirements. Since the conception of the Systematic Evaluation Program, Consumers Power Company has spent approximately $2,500,000 developing deterministic seismic analyses which address the seismic capacity of the plant. Such analyses, however, have been considered unacceptable by the NRC. Recently, Consumers Power Company has performed analysis utilizing the probabilistic risk assessment logic models and fragility estimates of certain equipment necessary to mitigate core damage during a seismic event to determine the seismic weak links. It is at such weak links that additional resources would be directed to seismically upgrade the plant should it be concluded that the seismic issue warrants additional attention. The analysis reveals, in ranked order of seismic capacity, the combinations of shutdown equipment and associated structures most important during an earthquake. As the level of seismic acceleration considered increases, the ordered list reveals which equipment or structures should be seismically upgraded first. As the list now stands, the emergency condenser supports represent the weakest link analyzed to fail at an acceleration of approximately 0.12g.

Ranked Position	Issue No	Issue Identification	Issue Scope
6	14	Seismic Design Considerations - SEP Topic III-6 (Contd)	The ordered list of equipment, however, is not complete due to the seismic capacity of certain equipment not being known (or at least large uncertainties exist in the estimate of such capacity). The analysis, therefore, recommends that certain actions be undertaken to assess that capability. The recommendations are as follows: 1. To ensure an ATWS is unlikely, evaluation identifying the weak links on the reactor internals is required and an evaluation ensuring that the CRDM discharge piping does not crimp is necessary. 2. Complete the cable tray evaluations being performed by the Seismic Qualification Owners Group and ascertain whether seismic dependencies exist between power supplies and electrical components in the routing of cable trays and conduit. 3. Inspect Valves M07050, M07053 and M07063 to ensure that the operators will not impact surrounding structures if motion occurs during an earthquake. 4. Evaluate or restrain the motion of M07070, M07071, M07051 and M07061 to ensure the motors do not impact surrounding structures if motion occurs during an earthquake. 5. Place a mechanical block on the cleanup demineralizer hoist to ensure it cannot travel over the enclosure spray valves. It should be noted that an evaluation of components other than those listed in Items 1 through 5 above is of no benefit until the capacity of these components has been shown to be greater

Ranked Position	Issue No	Issue Identification	Issue Scope
6	14	Seismic Design Considerations - SEP Topic III-6 (Contd)	than 0.12g. At that time, an evaluation of the methods by which the emergency condenser supports can be upgraded may be most beneficial in determining whether or not further seismic upgrading of the plant can be justified. As a partial resolution to this issue, the Technical Review Group (TRG) evaluated and ranked the above recommendations. As part of its evaluation, the TRG considered the following; (1) the estimated probability of earthquake which fails the emergency condenser supports is 8×10^{-5}/yr; 2.) the above recommendations may result in an additional expense of approximately \$250,000 without reducing any risk; and 3.) performing the above recommendations could be useful in ascertaining the actual seismic capacity of the plant.

Ranked Position	Issue No	Issue Identification	Issue Scope
	32	Upgrade Emergency Operating Procedures NUREG-0737	This issue, as initiated by the NRC as part of Supplement 1 to NUREG 0737, concerns the development of plant-specific, system-oriented emergency operating guidelines from generic guidelines which would then be used as the basis for the development of emergency operating procedures. It is expected that the guidelines will address multiple failures which result in certain types of reactor accidents. The Technical Review Group ranked the resolution for this issue because it felt that the development of such guidelines and subsequent procedures would enhance the operators' ability to cope with accidents and thereby be more capable of mitigating core damage and containment failure. It is currently predicted that an effort of 41-man days will be required for the operating staff to develop such procedures.

Ranked Position	Issue No	Issue Identification	Issue Scope
8	54	Plant Shielding - NUREG-0737	This issue, as initiated by the NRC as part of NUREG 0737, concerns the resultant exposure to plant personnel required to mitigate the effects of core damage and to obtain necessary air samples following a reactor accident. Present analysis shows that the resultant exposures received by plant personnel while in occupied areas are below NRC limits. Most operator actions required to mitigate the event will also result in exposures below NRC limits. Some actions, however, result in doses above NRC limits but are below the guidelines established by the National Council on Radiation Protection. The Technical Review Group (TRG) is nontheless concerned about the magnitude of exposure as predicted by the analysis. Therefore, the TRG ranked the concern rather than the resolution for this issue. The analysis predicts exposures of up to 8R (under worst-case conditions) for personnel entering the plant after the accident and less than 3R for control room personnel. Although the TRG felt that such an event has a low probability of occurrence (ie, a 10^{-5}/yr event from PRA), the TRG considered this issue important from a personnel safety standpoint and would recommend further study to address the concern.

Ranked Position	Issue No	Issue Identification	Issue Scope
9	18	RDS Reliability - High Pressure Recycle	This issue, as initiated by the plant staff, addresses the ability to cool down the reactor in the event of failure of both the main and emergency condenser without uncovering the core by activating the Reactor Depressurization System (RDS). In the event of such failure, Primary Coolant System (PCS) pressure will increase to the set point of the PCS safety valves. The valves will then open to vent the PCS and dump reactor coolant water to the containment. The water level at the bottom of containment will begin to rise as the valves cycle open and closed. The PCS pressure will be maintained at or near the safety valve set point. This issue primarily carries radionuclide release implications. On reaching the maximum permissible water level in containment, the operator will be left with the choice of manual RDS actuation to permit use of the Post-Incident System in recycling water back to the PCS or permitting containment water level to exceed design limits. The proposed resolution is to utilize the Post-Incident Cooling System to recirculate the water deposited in containment into the condenser hot well and subsequently back into the PCS via the high pressure feedwater pumps. This solution is preferred over the use of the RDS for PCS blowdown and subsequent uncovering of the core until the Core Spray System is capable of actuation. This issue was resolution-ranked by the Technical Review Group.

Ranked Position	Issue No	Issue Identification	Issue Scope
10	50A2	Containment Isolation - On-Line Testing of MSIV-SEP Topic VI-4	This issue concerns the degree of containment isolation afforded by the single containment isolation valve in the main steam line. The NRC staff presently is of the opinion that additional isolation should be installed. Plant-specific PRA reveals that the main steam line is the single largest contributor to containment isolation failure. The preferred resolution to this issue, as ranked by the Technical Review Group (TRG), is to: (1) perform periodic on-line testing to better assess and to improve main steam isolation valve (MSIV) isolation reliability and (2) install valve position indication for the operator to facilitate such testing. Past failures of the MSIV have occurred at cold or nearly shutdown conditions. The proposed on-line test is intended to demonstrate that the valve is significantly more reliable under hot operating conditions (conditions under which the valve must fulfill its intended safety function). PRA reveals the cost/benefit of the preferred resolution is \$185/man-Rem. The TRG also evaluated other alternatives for resolution such as: 1.) installing a second MSIV and 2.) qualifying the valves downstream of the MSIV. The TRG did not propose such resolutions since PRA data reveal that the cost benefit ratios for the two alternatives is \$4,000/man-Rem and \$11,000/man-Rem, respectively.

Ranked Position	Issue No	Issue Identification	Issue Scope
11	57	Control Room Habitability - NUREG-0737	This issue carries only personnel safety implications. Anlaysis was performed as required by NUREG 0737 to determine the doses to the control room operators as a result of a significant radionuclide release in containment and leakage (taken to be that allowed by plant Technical Specifications) out of containment. According to the analysis, the resulting dose to the operator is less than 1R to the whole body and less than 30R to the thyroid (taking credit for the donning of breathing apparatus). Although the resultant dose to the operator is considered acceptable by the NRC, the Technical Review Group (TRG) in general considered the dose to be more than desirable and concluded that additional analysis should be undertaken to determine a resolution to the issue. Since a resolution to the TRG's concern does not presently exist, the TRG ranked the concern instead of the resolution to this topic.

Ranked Position	Issue No	Issue Identification	Issue Scope
12	8	Single Channel Reset	This issue, as initiated by the plant staff, concerns the potential for LOCA through the scram dump tank during a "slow" scram (ie, when the scram valve pilot air header pressure slowly decays). During the slow header pressure decay, the scram valves open prior to the scram dump tank valves closing. This results in on open drain path from the reactor to the containment sump via the control rod drive system and scram dump tank. A similar draining situation may occur given a slow air header repressurization during Reactor Protection System reset. In this situation, the scram dump tank valves open prior to the scram valves closing. The resolution to the above issue, as evaluated and ranked by the TRG, is to perform a study to understand the coordination problem between the scram and scram dump tank valves. The investigation will result in the proposal of an appropriate modification to ensure that the Primary Coolant System is not partially drained.

Ranked Position	Issue No	Issue Identification	Issue Scope
13	85	Containment Overpressurization	The plant staff recognizes a need to resolve LER 81-016 "Containment Pressurization". Leakage of instrument and/or service air into containment has the potential to cause overpressurization of the containment during isolation conditions. A procedure to isolate the air sources appears to have merit and the proposed resolution was to evaluate accident sequences to determine if other complications must be addressed. It should be noted that in order to revise the procedures a facility change to install a backup compressed gas supply for the Reactor Depressurization System isolation valves must be implemented. It was the opinion of the Technical Review Group that this issue carries safe shutdown and radionuclide release implications. The TRG ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
14	22A	Organic Materials - SEP Topic VI-1	This issue and plans for its resolution are described in a letter to the NRC dated February 28, 1983. The Technical Review Group (TRG) assigned safe shutdown implications to this issue due to the possibility of the coatings within containment peeling off the surfaces under the harsh environmental conditions and plugging the recirculation lines. The TRG concluded that a need exists to evaluate the tenacity of the existing coatings under accident conditions and whether or not coating materials will plug the lines should such materials dislodge from the in-containment surfaces during such conditions. As a result, the TRG ranked as a proposed resolution the completion of such an evaluation and the implementation of an inspection program to periodically assess the condition of in-containment coatings.

Ranked Position	Issue No	Issue Identification	Issue Scope
15	48	Clean-Up Demineralizer Pump Replacement Investigation	This issue has plant availability implications in that the existing pumps frequently trip and require repair due to motor rotor problems and to pump cavitation. Without these pumps in operation, only about four days of plant operation can be sustained due to increasing levels of condensate conductivity which eventually require plant shutdown. This issue also carries safe shutdown and radionuclide release implications in that historical records show that the wearing of the motors' canned rotor has resulted in Primary Coolant System leakage. The Technical Review Group ranked the resolution to this issue. The resolution is to perform a study to determine whether or not a pump bypass line should be installed or the existing motors and pumps be replaced with those that are not susceptible to such problems. This issue is plant-initiated.

Ranked Position	Issue No	Issue Identification	Issue Scope
16	64	Containment ILRT	Recent NRC interpretations of 10 CFR 50, Appendix J, require additional Type A containment leak rate testing following certain Type B and Type C local leak rate test failures. The proposed resolution is to provide an evaluation showing that the interpretation would result in excessive testing which does not improve safety margins. The issue was ranked high for plant availability since the added testing requires plant shutdown and would be a considerable penalty over the projected plant lifetime.

Ranked Position	Issue No	Issue Identification	Issue Scope
17	4	Stack Gas Monitoring	The NRC, via NUREG-0737, Item II.F.1, identified the need for improved stack gas radioactive effluent monitoring. The project is nearly complete. The proposed resolution is to complete the project by obtaining the necessary spare parts from the vendor. The issue resolution was ranked high for plant availability because of regulatory requirements. It was noted that the Technical Review Group could not conclude that this issue carries any safe shutdov on radionuclide release implications.

Ranked Position	Issue No	Issue Identification	Issue Scope
18	17	PCS Isolation	This issue carries both safe shutdown and plant availability implications in that a probability exists for a loss of reactor coolant through Primary Coolant System (PCS) drain and vent lines which are presently only isolated at one point (ie, with one closed valve). The PRA shows that the probability of reactor coolant losses through such valves is 2×10^{-3}/yr and that the core damage probability of such an event is 6.9×10^{-5}/yr. The Technical Review Group ranked the resolution to this issue. The resolution is to review PCS piping and instrument drawings to determine the exact locations of such lines, and then to add additional isolation devices (ie, a second isolation valve or a pipe cap). This issue is plant-initiated.

Ranked Issue Position	No	Issue Identification	Issue Scope
19	84	Scram Dump Tank Valves - Lack of Redundancy	The plant staff recognizes the need to evaluate the potential for LOCA due to single failure in the scram dump tank vent and drain isolation system. Although no valve failures have ever occurred at Big Rock Point, the system is challenged during each scram. A LOCA would be limited to leakage flow through the control rod drives but would not be easily isolated. Evaluation to determine risk and possible solutions was proposed. It was the opinion of the Technical Review Group (TRG) that this issue carries both safe shutdown and radionuclide release implications. The TRG ranked aforementioned evaluation.

Ranked Position	Issue No	Issue Identification	Issue Scope
20	2	Acid Line Extension	This issue carries only personnel safety implications in that burns could occur to personnel while filling the neutralizer tank with acid. Presently, acid is carried by hand to fill the tank. The resolution to this issue is to install a one-inch line that would carry acid from a fill pump to the tank to preclude the necessity to fill by hand. The Technical Review Group ranked the aforementioned resolution to this plant-initiated issue.

Ranked Position	Issue No	Issue Identification	Issue Scope
21	72	Facility Modification on Annex and Warehouse	Modifications are proposed by the plant staff to improve the Q-stock storage area and also improve one office working area. The proposed resolution is to expand the present Q-stock area and relocate the offices presently in that warehouse to an area in the training annex that will require remodeling. The proposed resolution was ranked high for personnel safety since fire exits in the existing warehouse are less than desirable for use as an office area. The Technical Review Group ranked the proposed resolution to this plant-initiated issue.

Ranked Position	Issue No	Issue Identification	Issue Scope
22	77	Investigate Incore Availability Problem	The plant staff recognizes that the use of the existing neutron flux monitoring incore assemblies has proven to be expensive to meet the requirements of Technical Specifications 6.1.5 (f). The proposed resolution is to provide an evaluation which will allow technical specification relief from the present use of the incore monitors. The issue was ranked high for plant availability since incore chamber failures in certain locations could cause a plant derate or shutdown to repair. The Technical Review Group ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
23	75C	Fire Proection - Associated Circuits - Appendix R	10 CFR 50, Appendix R, requires that safe shutdown equipment be isolated from associated circuits such that hot shorts, shorts to ground or open circuits will not prevent operation of the safe shutdown equipment. After extensive analysis and discussion with the NRC over this equipment, we have committed to do the following: (1) Procedures are to be developed for numerous valves and one pump to determine if maloperation has occurred due to the fire. They would then address the repair of the equipment; ie, mainly disconnecting circuitry and operating valves manually. (These are items that have a long-term effect on safe shutdown. None were considered to have an immediate effect on hot shutdown). (2) The emergency condenser inlet valves were the only equipment identified that could prevent hot shutdown due to what the NRC considers a credible combination of shorts/open circuits. In other words, in the present configuration of the inlet valves control circuitry, a single short circuit of two wires in the control cable can close an inlet valve. Since we have run with one inlet valve closed in the past (due to a leaky outlet valve), it would take only one short circuit and one open circuit to prevent operation of the emergency condenser due to closed and disabled inlet valves. Since a fire in the electrical equipment room or penetration area can cause this, we could also disable the RDS/Core Spray and lose offsite power in the same fire, leaving no method to shut down the plant. The NRC considers this a credible event and requires protection of the inlet valve circuitry.

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Ranked Position	Issue No	Issue Identification	Issue Scope
23	75C	Fire Protection - Associated Circuits - Appendix R (Cont'd)	As a result, we committed to reroute one wire (the close coil wire) from each of the two circuits with the rest of the alternate shutdown circuits from the control room to the emergency condenser deck. This prevents the possibility of shorts closing the valves for fires in the electrical equipment room, penetration areas, etc. The Technical Review Group (TRG) believes that this issue is important to assure safe shutdown, and that the cost of the required modification is quite small.

Ranked Position	Issue No	Issue Identification	Issue Scope
24	5	Control Room Design Review - NUREG-0737	This issue, as initiated by the NRC per Supplement 1 to NUREG 0737, concerns the review of the adequacy of the control room design and the existing procedures to utilize the control room in an attempt to verify whether or not an effective man-machine interface will exist during accident conditions so that the reactor can be safely shut down. Experience at Three Mile Island and at other nuclear facilities has shown that existing procedures and controls are in certain cases inadequate and may hinder the operators' efforts to cope with an accident. The resolution to this issue is to perform a detailed control room design review which consists of: (1) performing an inventory of existing control room instrumentation and control equipment to ensure that the equipment called for in the emergency operating procedures is adequately designed for the intended purpose; (2) interviewing the operators to identify control room design deficiencies; and (3) validating the adequacy of the emergency operating procedures and the degree to which the existing controls and indications can be effectively utilized under accident conditions by conducting walk-throughs of design-basis accidents. It is the opinion of the Technical Review Group (TRG) that the control room design review will provide the justification for the necessity (or lack thereof) of a Safety Parameter Display System. The TRG ranked the above resolution to the issue. Although the TRG does not believe that the present size of the control room coupled with the lack of available panel space lends itself to equipment relocation or addition, the TRG does believe that the review will increase the operators' ability to cope with an accident to safely shut down the reactor. The TRG also

Ranked Position	Issue No	Issue Identification	Issue Scope
24	5	Control Room Design Review - NUREG-0737 (Contd)	believes to some degree that a better means of control panel equipment identification could result in decreasing the probability of plant trip due to operator error.

Ranked Position	Issue No	Issue Identification	Issue Scope
25	69	Acid and Caustic Tank Problems	The plant staff recognizes a need to improve the integrity and performance of pipes, pumps and tanks in those portions of the water treatment facility which utilize high caustic and acid solutions. The proposed resolution is to modify the system and replace materials. The issue resolution was ranked high for personnel safety by the Technical Review Group.

Ranked Position	Issue No	Issue Identification	Issue Scope
26	25	Wind and Tornado Loadings and Tornado Missiles - SEP Topics III-2 and III-A	This issue and plans for its resolution are described in a letter to the NRC dated February 28, 1983. The Technical Review Group (TRG) concluded that this issue carries both safe shutdown and radionuclide release implications. In its evaluation of the resolution, the TRG considered the following: (1) the probability of core damage as a result of failure from wind and tornado loadings is 8.2×10^{-6}/yr; (2) a recent Bechtel analysis shows that no damage occurs below 150 mph winds and no containment damage occurs below 250 mph winds; 3.) although the probability of occurrence is low, the effects of such an occurrence are significant; 4.) the cost of backfit would be substantial; and 5,) PRA can be useful in determining what the plant loading withstand capability is and should be.

Ranked Position	Issue No	Issue Identification	Issue Scope
27	1	Replace Tube Bundle in the "A" & "B" Heating and Coolant Heat Exchangers	This issue carries both radionuclide release and availability implications, in that periodic leaking through the heat exchanger tubes results in a breach of containment integrity and could result in a lengthy outage for repair. The resolution to this issue is to replace the existing tube bundle in each exchanger with stainless steel bundles to provide a more reliable containment boundary. Presently, the containment boundary is breached approximately once every five years. When leakage does occur, the entire bundle is valved out of service and the leak is isolated. The leakage condition is readily detectable, however, as the operator inspects for such conditions once per shift as controlled by Operations Department log sheets. The cost to replace the tube bundle is estimated as $12,000. The Technical Review Group ranked the resolution of this plant-initiated issue.

Ranked Position	Issue No	Issue Identification	Issue Scope
28	10	Ventilation for Panel C-52	The plant staff recognizes a need to improve the primary coolant system level instrumentation to maintain operator confidence in the accuracy of the level indications as they relate to emergency core cooling response. The proposed resolution is to improve the ventilation in Panel C-52 (in containment) to enhance power supply performance of the heating units for the constant head level chambers for the level detection elements. This will reduce the spurious alarms from the present system.

Ranked Position	Issue No	Issue Identification	Issue Scope
29	44	Verification of BS&B Valve Data	This plant-initiated issue concerns the air-operated valves in many systems throughout the plant. There is a possibility that the air pressures needed to stroke a valve may be greater than the present pressure setting for the flow conditions in the pipe under which the valve is to operate. Since some of the valves are installed in containment isolation systems and systems used for reactor shutdown, this issue carries radionuclide release and safe shutdown implications. The proposed resolution for this issue is to perform a study to determine the proper pressure setting for each air-operated valve considering the flow conditions in the pipe under which the valve is to operate, to verify the present pressure settings and to perform whatever setting adjustments are necessary. It is estimated that six-man months are required to complete the resolution. The Technical Review Group ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
30	63	Containment Purging/Venting - Install Debris Screens	The concern represented by this NRC-initiated issue is that in the event of a LOCA and subsequent pressurization of the containment, debris from inside the containment could be transmitted into the ventilation ductwork. Such debris could interfere with the closure of the ventilation valves and prohibit containment isolation. The resolution of this issue is to install a debris screen over the ventilation intake for each of the valves. The cost of such a resolution is relatively inexpensive. The Technical Review Group ranked the resolution to this issue. *

*NRC letter dated September 14, 1982.

Ranked Position	Issue No	Issue Identification	Issue Scope
31	50B	Containment Isolation - Leak Testing of Existing Check Valves - SEP Topic VI-4	This issue concerns the ability to isolate the instrument and service air lines that penetrate containment in the event of a break in these lines. These air systems are closed systems inside containment and do not feature valves for the specific purpose of containment isolation. The NRC's position is that Consumers Power Company should demonstrate that certain hand isolation valves, located upstream of the containment penetrations, satisfy the tenable operability requirements of Technical Specification 3.4.2(b). Two alternate resolutions for this issue were evaluated by the Technical Review Group (TRG). The preferable alternative is to periodically leak test the check valve in the service air line and the check valve in the instrument air line; both of which are located immediately inside the containment shell. It is currently believed that such a test program would result in the ability to quantify and reduce the leakage through the air systems. Plant-specific PRA reveals that the cost/benefit ratio of such a program is \$680/man-Rem. A less preferable alternative from the standpoint of cost/benefit is the installation of motor-operated isolation valves in the service and instrument air lines. The PRA reveals the cost/benefit ratio of this alternative to be \$12,600/man-Rem. Given the wide disparity in cost/benefit ratio between the two alternatives, the TRG elected to rank only the leak testing alternative.

Ranked Position	Issue No	Issue Identification	Issue Scope
32	86	Bypass of Motor Operated Valve Thermal Overloads - SEP Topic III-10.A	The Technical Review Group (TRG) evaluated and ranked as a resolution to this issue the commitments made in a letter to the NRC dated February 14, 1983. In the letter, Consumers Power Company committed to installing key switches and administrative controls to ensure that the thermal overload protection for six safety-related motor operated valves (MOV) is bypassed during all phases of plant operation except when the valves are subject to testing or maintenance. Consumers Power Company committed to install the switches and administrative controls for the following valves: Emergency Condenser Inlet Valves MO-7052 and MO-7062, Firewater to Core Spray Heat Exchanger Valve MO-7066, Reactor Building Emergency Spray Backup Valve MO-7068 and Reactor Emergency Cooling Spray Backup Valves MO-7070 and MO-7071. During its evaluation, the TRG considered the following: 1.) recent PRA cost/benefit analysis reveals that the modification of valves MO-7070 and MO-7071 is marginally cost-justified and the modification of the other four valves is not cost-justified, and 2.) plant-specific historical data shows that no MOV failures were the result of faulty thermal overload protection.

Ranked Position	Issue No	Issue Identification	Issue Scope
33	76	Containment High-Range Monitor - NUREG-0737	The NRC, via NUREG-0737, Item II.F.1(3), requires that the containment high-range monitor be calibrated onsite using a radioactive source. The proposed resolution is to obtain a source for calibration. The issue resolution is ranked medium on personnel safety since accurate dose rate assessment external to containment may be important following an accident. The Technical Review Group ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
34	21	Recirc Pump Trip	The NRC proposes in this ATWS-related issue an automatic recirculation pump trip on low steam drum level and high reactor pressure as a means to mitigate an ATWS event. The proposed resolution is to justify not installing the equipment by showing that such a modification is not cost effective. Cost estimates and risk reduction from the PRA study indicate a figure of $93,000/man-Rem saved. The issue resolution was ranked medium by the Technical Review Group on the basis of safe shutdown considerations and potential for uncontrolled radioactive releases.

Ranked Position	Issue No	Issue Identification	Issue Scope
35	52	High Energy Line Break Inside Containment - SEP Topic III-5.A	This issue and its planned resolution are described in a letter to the NRC dated February 28, 1983. The Technical Review Group (TRG) concluded that this issue carries both safe shutdown and radionuclide release implications in that systems required for safe shutdown and release mitigation are susceptible to such breaks. The TRG considered the following facts during the course of its evaluation: (1) a NUTECH analysis revealed that failure of safety-related components could occur due to pipe whip and/or jet impingement at certain locations; (2) plant-specific PRA reveals that the probability of core damage due to such an event is 5×10^{-6}/yr; (3) according to PRA, the cost/benefit ratio of modifications designed to reduce all risk associated with this issue (ie, installation of missile shields, installation of whip restraints and reroute of piping) is $160,000/man-Rem; and (4) PRA, as supplemented by documentation of leakage detection capability, provides a less expensive but adequate means to address the issue. The TRG ranked the PRA (Item 4 above) as the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
36	7	Scram Dump Tank Level Instrumentation - Generic Letter 81-18	This NRC-initiated issue concerns the adequacy of the design of the existing scram dump tank level instrumentation. The NRC is concerned that the present design lends itself to common mode failure and, therefore, to a possible ATWS condition. The NRC cites as design deficiences, the lack of diversity and separation in the existing level switch instrumentation. Presently, four identical level switches are mounted on a common instrument header and serve to provide scram dump tank level signals to the Reactor Protection System. In the past, the NRC has recommended the installation of diverse instrumentation and further evaluation to determine the need for a redundant header. The Technical Review Group (TRG) evaluated and ranked a resolution to the issue which consisted of installing diverse instruments and redundant header piping. In its evaluations, the TRG utilized the following information: (1) plant-specific PRA reveals that the contribution to core damage probability from failure to scram due to all possible common-mode failures (eg, common-mode failures attributable to lack of instrumentation diversity and lack of header redundancy) is only 3×10^{-7}/yr; (2) PRA reveals that the cost/benefit ratio of a modification to eliminate common-mode failures is approximately $15,000/man-Rem; and (3) should ATWS occur, the standby liquid poison system is available to render and maintain the reactor in a subcritical condition.

Ranked Position	Issue No	Issue Identification	Issue Scope
37	80	Performance of BWR Safety Valves	As an outgrowth of NRC regulation (via NUREG-0737, Item II.D.1 regarding performance testing of safety-relief valves), the valve vendor has identified a need to optimize the performance of the six steam drum safety-relief valves. This will provide flow and reset characteristics per the original specifications for operation at the present operating pressure. The proposed resolution is to install spring components as recommended by the vendor. The TRG considered this issue to carry safe shutdown implications. The TRG ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
38	35B	FHSR Update Study	NRC regulation 10 CFR 50.71(e) requires power reactors to maintain an updated Final Hazard Summary Report in the future. This would provide a convenient basis for safety evaluations per 10 CFR 50.59. The proposed resolution is to evaluate a method of indexing existing documents to provide a workable substitute. The proposed resolution was ranked as a safe shutdown item and a radioactive release item. The Technical Review Group ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
39	83	Full Stroke Testing of RDS Depressurization Valves	The plant staff feels that partial stroke testing of the Reactor Depressurizing System Depressurization Valves may not adequately verify operability of the system. The present test, performed during cold shutdown, only provides means of verifying a small fraction of total stroke. Evaluation to determine suitability of the present test or need for improvement was proposed. It was the opinion of the Technical Review Group (TRG) that this issue carries both safe shutdown and radionuclide release implications. The TRG ranked the aforementioned evaluation.

Ranked Position	Issue No	Issue Identification	Issue Scope
40	50D	Containment Isolation - Add Control Circuit to Treated Waste Valve - SEP Topic VI-4	This issue concerns the ability to isolate the treated water line due to a line break during a LOCA. The NRC staff recommends the installation of suitable isolation equipment or controls to afford greater isolation capability. The resolution of this issue, as ranked by the Technical Review Group, is to install automatic actuation to the existing air-operated valve in this line. Plant-specific PRA reveals that the cost/benefit of such an installation is \$17,000/man-Rem.

Ranked Position	Issue No	Issue Identification	Issue Scope
41	20	Instrumentation to Detect Inadequate Core Cooling - NUREG-0737	The NRC, via NUREG-0737, Item II.F.2, proposes wide range level instrumentation for the primary system for use during transients or a LOCA. The proposed resolution is to show that such instrumentation is not cost effective. The cost is estimated at $1,000,000 and the perception is that very little safety benefit can be derived out of such modification. The Technical Review Group (TRG) assigned safe shutdown implications to this issue. The TRG ranked the aforementioned proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
42	73	Control of Heavy Loads	This NRC-initiated issue (NUREG 0612) deals with the ability to safely manage the transfer of heavy loads during the performance of plant operating, maintenance or refueling activity. The issue carries safe shutdown and radionuclide release implications when considering the drop of certain heavy loads in certain circumstances. The resolution for this issue, as evaluated by the Technical Review Group (TRG), is twofold: (1) to revise existing procedures to manage better the control of heavy loads; and (2) to modify the containment crane interlocks to prohibit crane travel over certain areas. Since the procedural revisions are essentially complete, the TRG ranked only the second portion of the resolution (ie, the modification of containment crane interlocks). In performing its evaluation, the TRG considered plant-specific PRA which shows that the approximate core damage attributable to such an event is 1×10^{-5}/yr and the cost/benefit ratio of installing interlocks is $70,000/man-Rem.

Ranked Position	Issue No	Issue Identification	Issue Scope
43	23	BOP QA Program	Plant staff members are considering the potential improvement in plant reliability and availability by application of the Quality Assurance Program to the entire plant. The proposal is perceived to be very expensive for the derived potential benefit. The Technical Review Group (TRG) considers this INPO-initiated issue to carry plant availability issues. The TRG ranked the application of the QA program to the entire plant.

Ranked Position	Issue No	Issue Identification	Issue Scope
44	70	Emergency D-Gen Panel Vent System	The plant staff recognizes a need to improve room temperature control in the emergency diesel generator room. The proposed resolution is to provide an automatic temperature-controlled ventilation damper to reduce the need for operator attention during specific accident conditions. The Technical Review Group (TRG) is of the opinion that this plant-initiated issue carries safe shutdown implications. The TRG ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
45	9	Reactor Cooling Water System Pressure Study	This plant-initiated issue concerns the leakage of Reactor Cooling Water System (RCWS) water into the Radwaste System. During rotation of the RCWS pumps, the RCWS relief valves open and stick open. As a result, RCWS tank level drops. This issue has plant availability implications in that access to repair sticking relief valves is limited to periods when the plant is shut down. The relief valves are located in the regenerative heat exchanger room where significant radiation field exists during power operation. The resolution to this issue, as ranked by the Technical Review Group, is to perform a study to determine why the relief valves are opening and remaining open. Based on the results of the study, an appropriate modification will be recommended.

Ranked Position	Issue No	Issue Identification	Issue Scope
46	66	Radaste Monitor Flush Timer	Members of the plant staff recognize a need to reduce flow into the Radwaste system caused by unattended flushing of the radwaste radiation monitor. The proposed resolution is to add an automatic timer and valve controls to reduce the chance of excessive water going to radwaste for processing. The Technical Review Group (TRG) considers this plant-initiated issue to carry radionuclide release implications. The TRG ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
47	37	Flooding Potential and Capability To Cope With Design Basis Flooding - SEP Topics II-3.B and II-3.B.1	This issue is identified as are its plans for resolution in a letter to the NRC dated February 28, 1983. Preliminary analyses performed by Consumers Power Company indicate that flood levels are not significant and therefore do not jeopardize the proper operation of safety-related equipment. The Technical Review Group concluded that although such analyses should be submitted to the NRC, no further work to resolve this issue is necessary.

Ranked Position	Issue No	Issue Identification	Issue Scope
48	38	Safety-Related Water Supply - SEP Topic II-3.C	This issue is identified as are its plans for resolution in a letter to the NRC dated February 28, 1983. Preliminary Consumers Power Company analyses show that the plant can withdraw emergency cooling water under conditions of probable minimum lake water level. The Technical Review Group concluded that although such analyses should be submitted to the NRC, no further work to resolve this issue is necessary.

Ranked Position	Issue No	Issue Identification	Issue Scope
49	13	Purity of Primary Coolant - SEP Topic V-12	This issue is identified as are its plans for resolution in a letter to the NRC dated February 28, 1983. The Technical Review Group (TRG) evaluated and ranked the plans for resolution as identified in the letter. During the course of its evaluation, the TRG concluded the following: (1) 20 years of operating history substantiates the opinion that existing administrative controls and technical specifications are an adequate means of control for Primary Coolant System water purity and (2) the ongoing ISI Program has shown that stress corrosion cracking is not a major concern at Big Rock Point.

Ranked Position	Issue No	Issue Identification	Issue Scope
50	39	Effects of High Water Level - SEP Topic III-3.A.	The scope is identical to that described for SEP Topics II-3.B and II-3.B.1.

Ranked Position	Issue No	Issue Identification	Issue Scope
51	50C	Containment Isolation - Benefit of Installing Isolation Valves in Heating, Cooling and Service Water Systems - SEP Topic VI-4.	This issue concerns the ability to isolate the Heating, Cooling and Service Water Systems in the event of a leak in these systems during a LOCA. The NRC is of the opinion that the above systems should be modified such that the leakage can be eliminated or controlled. The resolution evaluated and ranked by the Technical Review Group is to install motor-operated valves in each of the above systems. Plant-specific PRA indicates that the cost/benefit of such a modification is $46,000/man-Rem.

Ranked Position	Issue No	Issue Identification	Issue Scope
52	31	Definition of Operability	The NRC has requested that a new definition of operability and a blanket LCO (for items not specifically covered) be incorporated into the Technical Specification based on the BWR Standard Technical Specification. The proposed resolution is to attempt to incorporate workable language into a technical specification proposal. Technical Review Group (TRG) considers this issue the carry safe shutdown implications. The TRG ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
53	34	Control Room Air Conditioning	The plant staff recognizes a need to control the air temperature in the control room for operator comfort. The present service water system is inadequate during hot weather when the service water (Lake Michigan water) is at its maximum temperature. The proposed resolution was to provide refrigeration-type air conditioning. The TRG ranked the proposed resolution. Consumers Power Company is currently exploring other alternatives to resolving this issue. The Technical Review Group (TRG) considers this issue to carry safe shutdown implications.

Ranked Position	Issue No	Issue Identification	Issue Scope
54	50E	Containment Isolation - Air Lock Testing - SEP Topic VI-4	This issue concerns the frequency of air lock leakage testing as it pertains to the ability to detect and to correct significant leakage through the air lock seals. Appendix J to 10 CFR 50 requires that the air locks be leak tested within 72 hours after each use or every 72 hours if the air locks are used daily. Presently, the air locks at Big Rock Point are tested once per six months. Data from past leakage tests indicates that the leakage is consistently quite low. Plant-specific PRA has evaluated the cost/benefit of incorporating a more frequent testing program as recommended in Appendix J. PRA shows that the cost/benefit ratio for such a program is $68,000/man-Rem. The Technical Review Group ranked the resolution to this issue which is to provide the NRC with such PRA evaluation to show that the proposed increase in testing frequency is not cost-justified.

Ranked Position	Issue No	Issue Identification	Issue Scope
55	50F	Containment Isolation - Hand Isolation of Instrument Lines - SEP Topic VI-4	This issue concerns the isolation of instrument lines that penetrate reactor containment. It is currently the opinion of the NRC staff that since these lines do not possess isolation features according to 10 CFR 50 Appendix A, General Design Criterion 55, that at a minimum the licensee should demonstrate that the locations of the existing valves satisfy tenability criteria regarding the hand isolation of such lines. The Technical Review Group (TRG) evaluated and ranked the resolution to this issue. The resolution is to demonstrate that the valves are capable of being manipulated to isolate the affected line. The TRG did not feel that the effort was warranted since leaks in the instrument lines require passive failure; an event on the order of 10^{-9}/ft/yr. In addition, the TRG concluded that a significant portion of the breaks would render the locations uninhabitable due to very high radiation fields.

Ranked Position	Issue No	Issue Identification	Issue Scope
56	62	Revise Drawings	Prior commitments made in response to NRC IE Bulletins 81-15 and 79-08 call for system drawings showing valve lineups to coincide with plant check-off sheets. The proposed resolution is to complete the drawing revision project which is 96% complete. The Technical Review Group (TRG) assigned safe shutdown implications to this issue. Although the plant plans to complete the revision, the TRG ranked the proposed resolution.

Ranked Position	Issue No	Issue Identification	Issue Scope
57	22B	Post-Accident Chemistry - SEP Topic VI-1	This issue is identified as are its plans for resolution in a letter to the NRC dated February 28, 1983. The Technical Review Group (TRG) evaluated and ranked the resolution as proposed in the aforementioned letter. During its evaluation, the TRG considered the following: (1) the chloride content of Lake Michigan is low and (2) existing technical specifications are adequate. Although the TRG concluded that the evaluation described in the aforementioned letter should be submitted to the NRC, the TRG also concluded that no additional work should be done to resolve this issue.

Ranked Position	Issue No	Issue Identification	Issue Scope
58	74	Primary Coolant System Vents - NUREG-0737	This NRC-initiated issue concerns the ability vent the Primary Coolant System (PCS) of hydrogen which can accumulate during a core damage accident and, subsequently, to safely shut down the plant. The resolution to this issue is to install vents in the PCS to provide such an ability. The plant staff has installed such vents on the reactor. However, they are not presently operational. The resolution of this issue is to complete the vent project by: (1) providing test connections; (2) installing seismic supports: and (3) preparing implementing procedures. The Technical Review Group (TRG) ranked this resolution and considered the following information: (1) the PCS does not need additional hydrogen venting capability since the core must uncover to get significant hydrogen generation and the Reactor Depressurization System will have actuated to vent the reactor and PCS under these conditions; (2) plant-specific PRA reveals that approximate core damage probability attributable to such an event is 9.4×10^{-7}/yr; and (3) the cost/benefit ratio for seismically qualifying the existing vents, as determined by PRA, is \$54,000/man-Rem.

Ranked Position	Issue No	Issue Identification	Issue Scope
59	30	Radiological Effluent Technical Specifications	This issue concerns the ability to monitor in specific detail the type and magnitude of radiological effluents released. Currently, the NRC recommends the adoption of standard radiological technical specifications. Such specifications require that the plant be capable of monitoring with greater sensitivity released radionuclides. The Technical Review Group (TRG) evaluated and ranked the above recommedation. The TRG concluded that the adoption of such additional requirements will not result in reducing releases. The TRG also concluded the following; (1) the plant currently meets all of the release guidelines; (2) additional plant staff (perhaps four or five people) will be required to support additional sampling and analysis; and (3) new monitors will have to be procured and installed.

Ranked Position	Issue No	Issue Identification	Issue Scope
60	19	Hydrogen Monitoring - NUREG-0737	The NRC concern is that systems do not presently exist to inform the operator of hydrogen levels within containment such that mitigation equipment (eg, hydrogen recombiners) can be placed into service at the proper time. This issue does not carry safety implications for Big Rock Point since even if the entire core melts, hydrogen detonation levels will not be reached. Such levels will not be reached due to the large volume inside containment relative to the small fuel inventory in the core. The Technical Review Group ranked the NRC concern rather than a resolution to that concern since the concern does not appear to be realistic.

Ranked Position	Issue No	Issue Identification	Issue Scope
61	50G	Containment Isolation - Pneumatic Test of MSIV - SEP Topic VI-4	This issue concerns the manner in which the plant staff currently leak tests the Main Steam Isolation Valve (MSIV). The valve is presently tested at each refueling, utilizing water at 1700 pounds pressure during the hydrostatic test of the Primary Coolant System. Leakage is measured in terms of drops/second. In addition, the MSIV is tested with air as part of the Integrated Leak Rate Test (ILRT) every 40 months. The NRC recommends that the plant staff either: (1) develop an appropriate air or nitrogen test of the MSIV along with other valves in the main steam system, or (2) develop appropriate acceptance criteria for hydrostatic tests of the MSIV in conjunction with trends from the ILRTs. The Technical Review Group (TRG) ranked the NRC recommendation to resolve the issue. The TRG, in its evaluations, considered such facts as: (1) an ILRT at Big Rock Point has never failed as a result of leakage through the penetration employed by the main steam line; (2) water testing is a reliable means to detect leakage; and (3) a leak test program which includes both the ILRT and the water test is sufficient.

Ranked Position	Issue No	Issue Identification	Issue Scope
62	51	Design Codes, Criteria and Load Combinations - SEP Topic III-7.B	This issue is identified as are its plans for resolution in a letter to the NRC dated February 28, 1983. The Technical Review Group ranked the resolution considering that an in-depth review of the latest Franklin Research Center Technical Evaluation Report would require approximately four to five man-months of effort and would, in itself, result in no risk reduction. In addition, the TRG felt that further review would show that no substantial plant upgrade is necessary.

Ranked Position	Issue No	Issue Identification	Issue Scope
63	81	Position Indication of PORV	This NRC-initiated issue concerns the ability to monitor the position of Power-Operated Relief Valves (PORVs) such that a LOCA similar to that at Three Mile Island Unit II can be readily detected and mitigated. Currently, the NRC is requiring direct indication of PORVs and safety-relief valves. Presently, the plant is equipped with non-environmentally qualified safety-relief valve indication. The plant does not feature PORVs. The Technical Review Group evaluated and ranked the proposed resolution to this issue. The resolution evaluated is to install a positive, environmentally qualified means of detecting valve position. The TRG concluded that such a system is unwarranted since the safety-relief valves cannot be positioned. The relief valves are simply spring-loaded valves that open and close at a pre-established Primary Coolant System pressure. The TRG also noted that an open safety relief valve would be detected by area humidity detectors. In addition, open relief valves can be heard by plant staff from outside the containment.

Ranked Position	Issue No	Issue Identification	Issue Scope
64	75B	Fire Protection - Loss of Offsite Power (Radiant Energy Shield) - Appendix R	10 CFR 50, Appendix R, requires that safe shutdown be achieved without use of offsite power for 72 hours following the fire; the basis for this being either that the fire destroys the off-site power source or that turbine trip causes enough disturbance of the electrical grid to trip offsite power breakers. Due to the small size of Big Rock Point, the second reason has a very low probability of occurrence. Consumers Power Company attempted to ask for exemption from the second reason and when discussing such a request with the NRC staff, Consumers Power Company was advised not to do so since the Commission would not approve such a request. We are, therefore, forced to rely on RDS/Core Spray as an alternate means of safe shutdown in the event of any fire that affects the alternate shutdown panel equipment. In other words, for a fire in the core spray pump room or the emergency condenser deck or the south face of the steam drum wall, which would disable the alternate shutdown system, we cannot claim use of the main condenser to safely shut down. Instead, we must rely on RDS/Core Spray. This leads to the fact that we must now consider RDS/Core Spray to be redundant to the alternate shutdown system. This requires us to meet the Appendix R requirements for separation between redundant systems. To meet the separation criteria, the following must be done: (1) Radiant energy shields must be installed between the emergency condenser outlet valve conduits and the RDS conduits and valves (both on the south face of the steam drum enclosure and on the emergency condenser deck;

Ranked Position	Issue No	Issue Identification	Issue Scope
64	75B	Fire Protection - Loss of Offsite Power (Radiant Energy Shield) - Appendix R (Cont'd)	ie, wherever the circuits are within 20 feet of each other). (2) A Radiant energy shield must be installed between one emergency condenser inlet valve and the RDS valves on the emergency condenser deck. NOTE: The inlet valve circuit is in the same conduit as the outlet valve up the wall and across most of the deck. Therefore, only one shield is needed until the wires split on the deck. (3) A three-hour fire barrier must be constructed between the core spray pumps and all alternate shutdown panel equipment and conduits. This will include tearing out and replacing the concrete block wall in the entrance to the core spray pump room and rerouting/ redesigning conduit runs from the battery outside the pump room. (The seismic conduit design, which was already completed, required the conduit to be routed directly into the room and over to the shutdown panel. The conduit must now be redesigned to run underground outside the room and come in the back of the room inside a three-hour shutdown panel enclosure.) The Technical Review Group (TRG) evaluated the above three actions as the proposed resolution. During the course of its evaluation, the TRG considered the following: (1) a fire in a core spray room, along the emergency condenser deck or up the steam drum wall is very unlikely; (2) a fire in the aforementioned areas coincident with a loss of offsite power is incredible; and (3) the cost to complete the proposed resolution is not justified given the likelihood of fire in the areas of concern coincident with the loss of offsite power.

Consumers Power Company
Big Rock Point Plant
Docket 50-155

INTEGRATED ASSESSMENT OF OPEN ISSUES AND SCHEDULE FOR ISSUE RESOLUTION (INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND GENERIC LETTER 82-33 ISSUES)

June 1, 1983

Attachment No. 4

Justification for Relief from
Certain NRC-Initiated Issues
Categorized as Having Either
Low or No Safety Significance

3 pages

ATTACHMENT 4

JUSTIFICATION FOR RELIEF FROM
CERTAIN NRC-INITIATED ISSUES
CATEGORIZED AS HAVING EITHER
LOW OR NO SAFETY SIGNIFICANCE
(Page 1 of 3)

Rank Position	Issue No	Safety Significance Category	Issue Title	Justification For Relief
34	21	low	Recirculation Pump Trip	refer to Consumers Power Company letter dated February 26, 1981
36	7	low	Scram Dump Tank Level Instrumentation	refer to Consumers Power Company letter dated November 2, 1981
37	80	low	Performance of BWR Safety Valves	resolution to be completed during current refueling outage
41	20	low	Instrumentation to Detect Inadequate Core Cooling	refer to Consumers Power Company letter dated July 31, 1981
47	37	none	Flooding Potential & Capability to Cope - SEP Topics II-3.B & II-3.B.1	justification to be docketed by 6/24/83
48	38	none	Safety - Related Water Supply - SEP Topic II-.3.C	justification to be docketed by 6/24/83
49	13	none	Purity of Primary Coolant - SEP Topic V-12	justification to be docketed by 6/24/83
50	39	none	Effects of High Water Level - SEP Topic III-3.A	justification to be docketed by 6/24/83

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ATTACHMENT 4

JUSTIFICATION FOR RELIEF FROM
CERTAIN NRC-INITIATED ISSUES
CATEGORIZED AS HAVING EITHER
LOW OR NO SAFETY SIGNIFICANCE
(Page 2 of 3)

Rank Position	Issue No	Safety Significance Category	Issue Title	Justification For Relief
51	50C	none	Containment Isolation - Valves in Heating, Cooling and Service Water Lines -	justification to be docketed by 6/24/83
52	31	none	Definition of Operability	justification to be docketed by 6/1/83
54	50E	none	Containment Isolation - Air Lock Testing - SEP Topic VI-4	justification to be docketed by 6/24/83
55	50F	none	Containment Isolation - Hand Isolation of Instrument Lines - SEP Topic VI-4	justification to be docketed by 6/24/83
56	62	none	Revise Drawings	drawing revision project is already 96% complete and therefore the project is not scheduled (the remaining 4% will be complete)
57	13	none	Post Accident Chemistry - SEP Topic V-12	justification to be docketed by 6/24/83
84	74	none	Reactor Coolant System High Point Vents - NUREG 0737	refer to Consumers Power Company letter dated April 19, 1983

ATTACHMENT 4

JUSTIFICATION FOR RELIEF FROM
CERTAIN NRC-INITIATED ISSUES
CATEGORIZED AS HAVING EITHER
LOW OR NO SAFETY SIGNIFICANCE

Rank Position	Issue No	Safety Significance Category	Issue Title	Justification For Relief
59	30	none	Radiological Effluent Technical Specifications	refer to Consumers Power Company letter dated November 13, 1978 (The adoption of RETS, as currently proposed by NRC, is not justified for Big Rock Point Plant. An alternate approach may be evaluated and ranked during a future Technical Review Group meeting.)
60	19	none	Hydrogen Monitoring - NUREG 0737	refer to Consumers Power Company letter dated December 19, 1980, enclosure entitled "Consumers Power Company's NUREG 0737 Response - Big Rock Point Nuclear Plant", Item II.E.4.1
61	50G	none	Containment Isolation - Pneumatic Test of MSIV - - SEP Topic VI-4	justification will be docketed by 6/24/83
62	51	none	Design Codes, Criteria and Load Combinations - SEP Topic III-7.B	refer to Issue #51 scope statement (Attachment 4)
63	81	none	Position Indication of PORV	refer to issue #81 scope statement (Attachment 4)
64	75B	none	Fire Protection - Loss of Offsite Power (Radiant Energy Shield) - Appendix R	refer to issue #75B scope statement (Attachment 4)

Consumers Power Company
Big Rock Point Plant
Docket 50-155

INTEGRATED ASSESSMENT OF OPEN ISSUES AND SCHEDULE FOR ISSUE RESOLUTION (INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND GENERIC LETTER 82-33 ISSUES)

June 1, 1983

Attachment No. 5

Big Rock Point Plant
Living Schedule

9 pages

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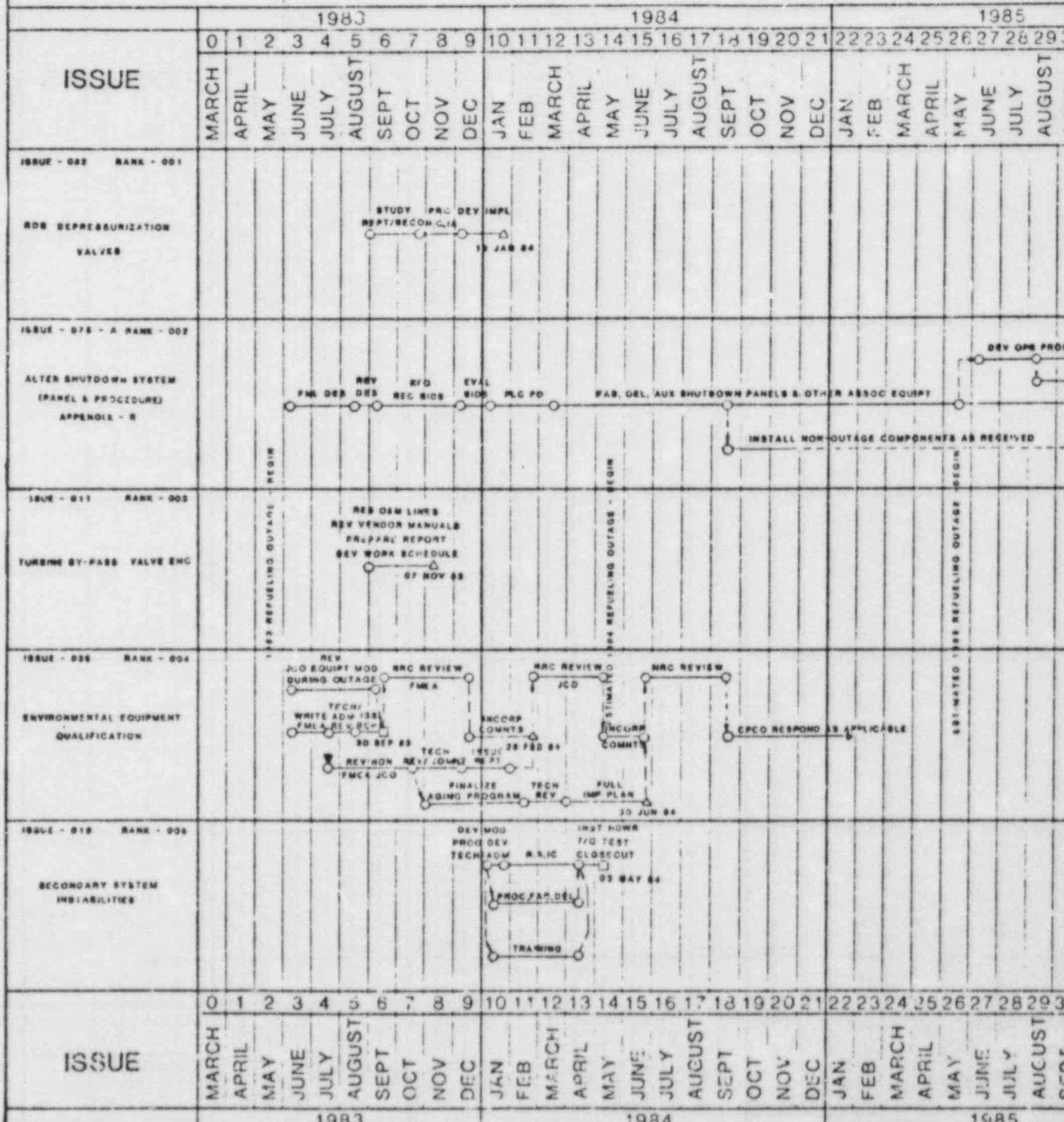

Attachment 5

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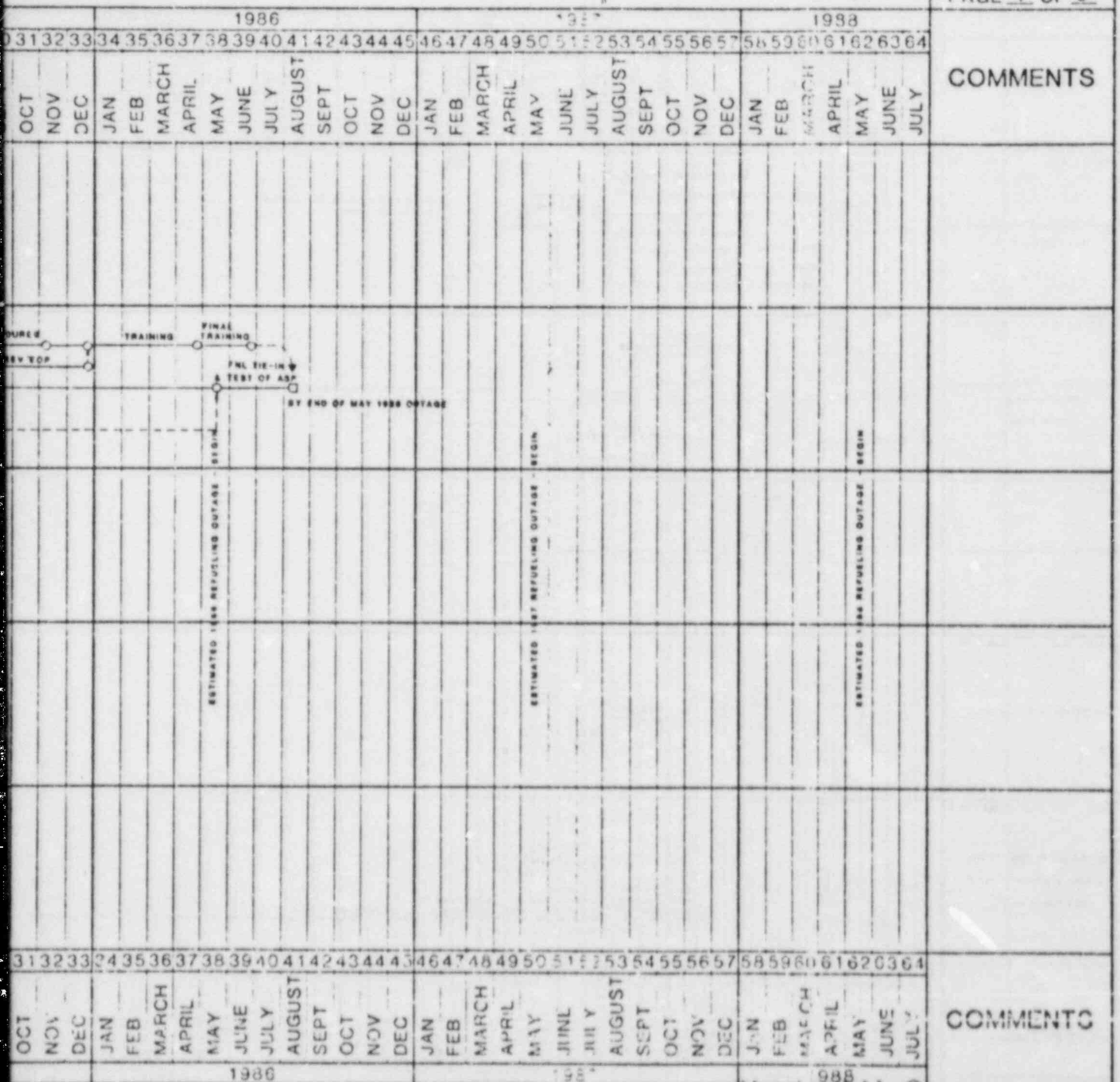

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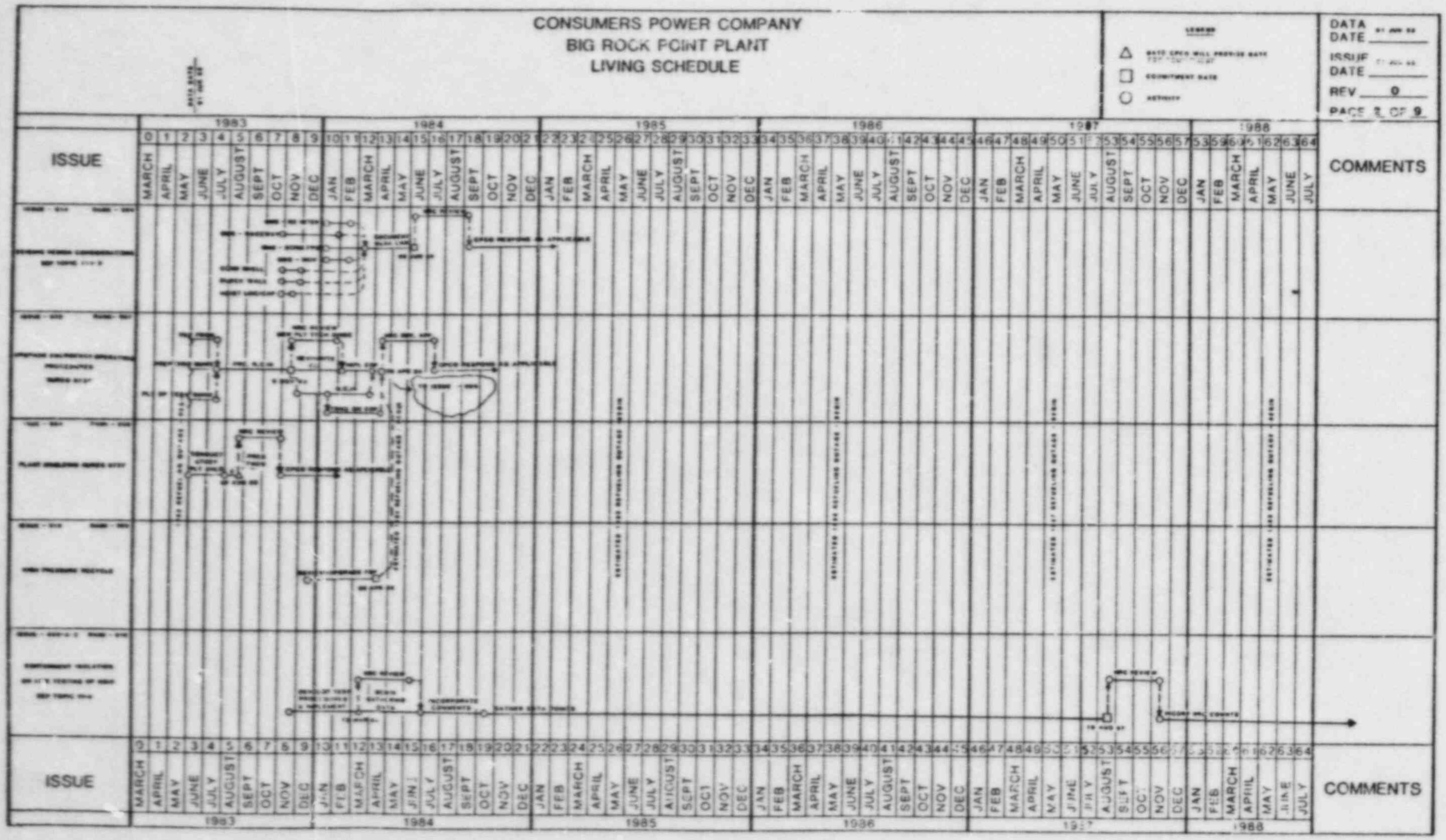

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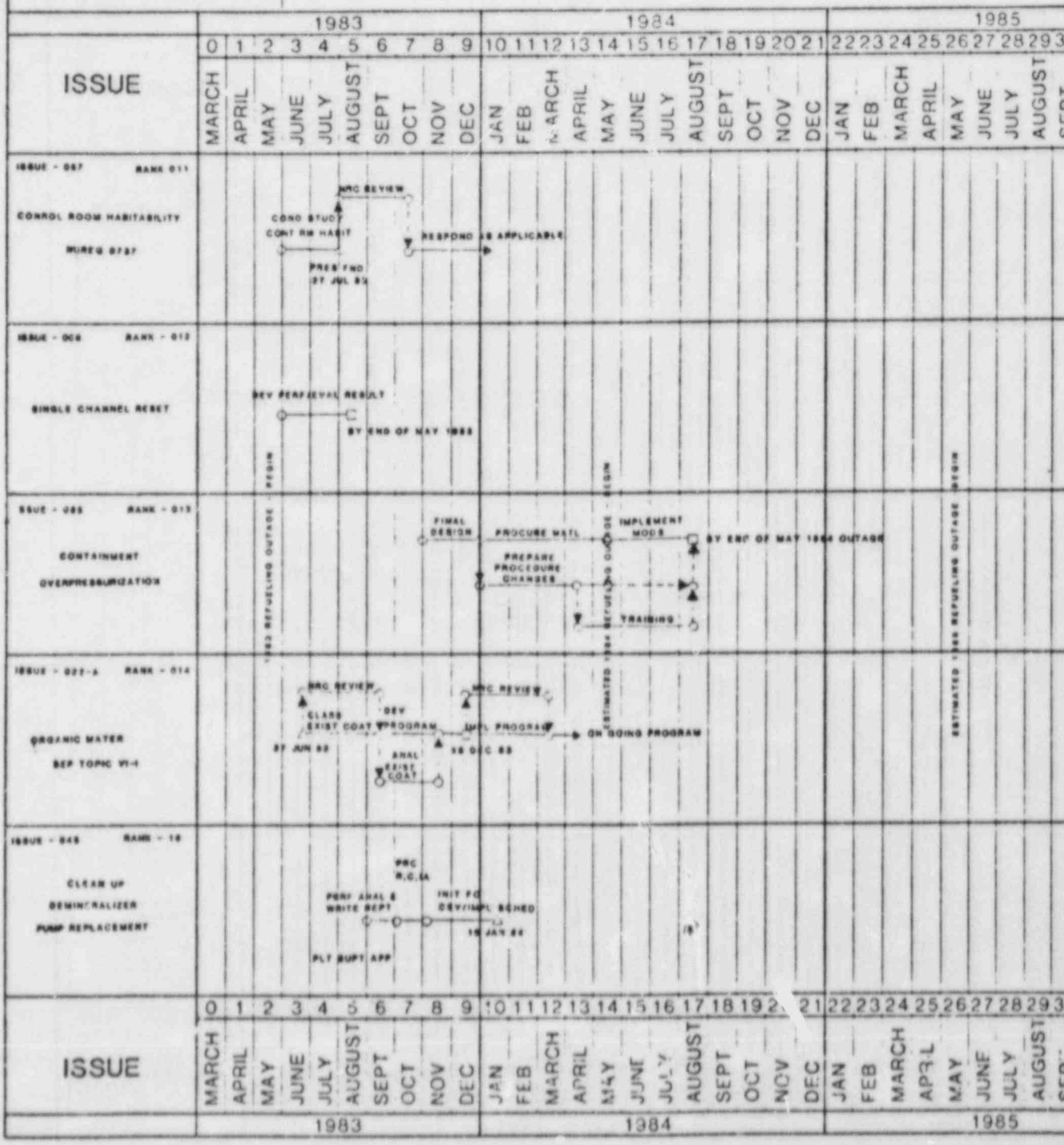

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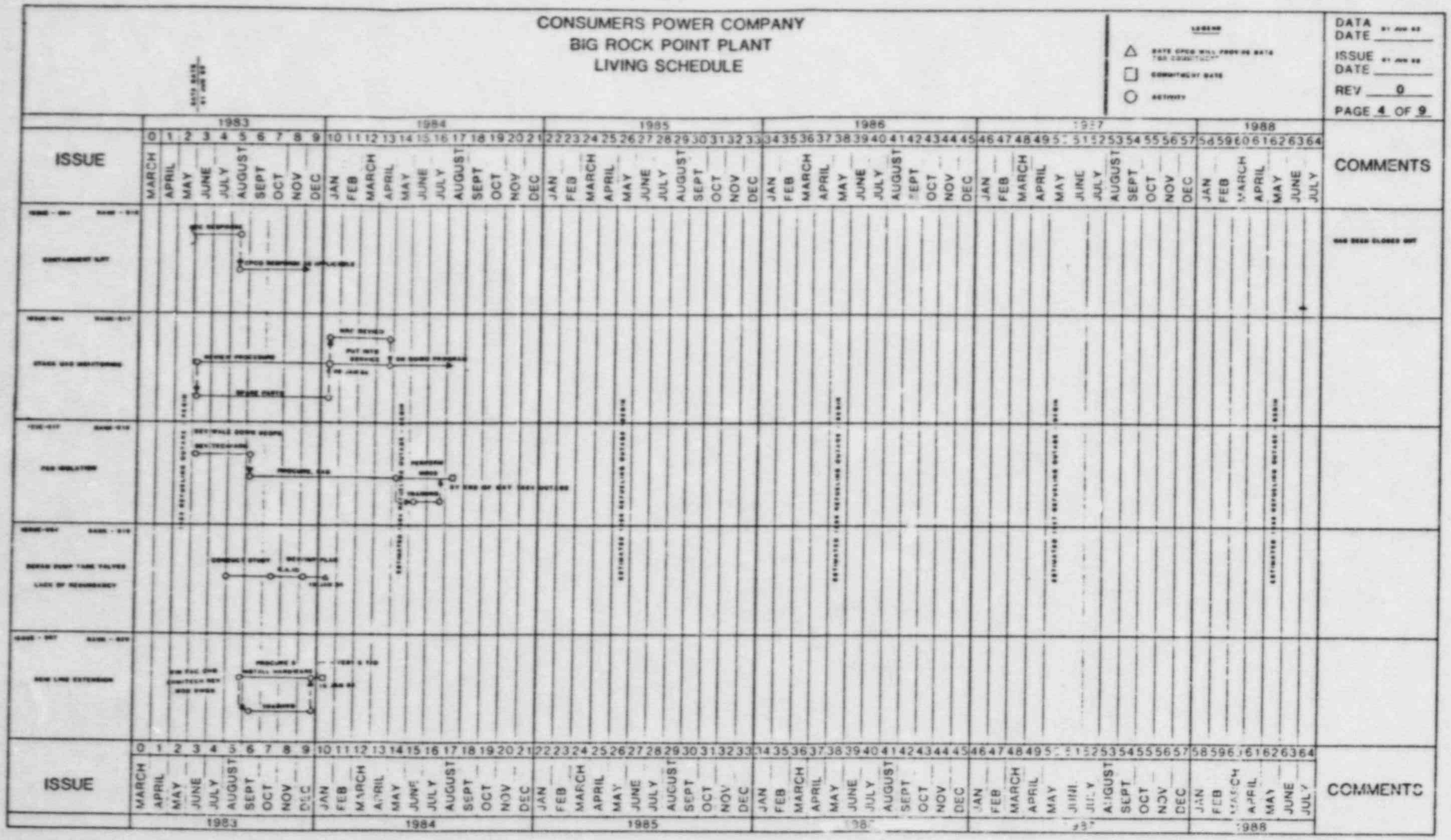

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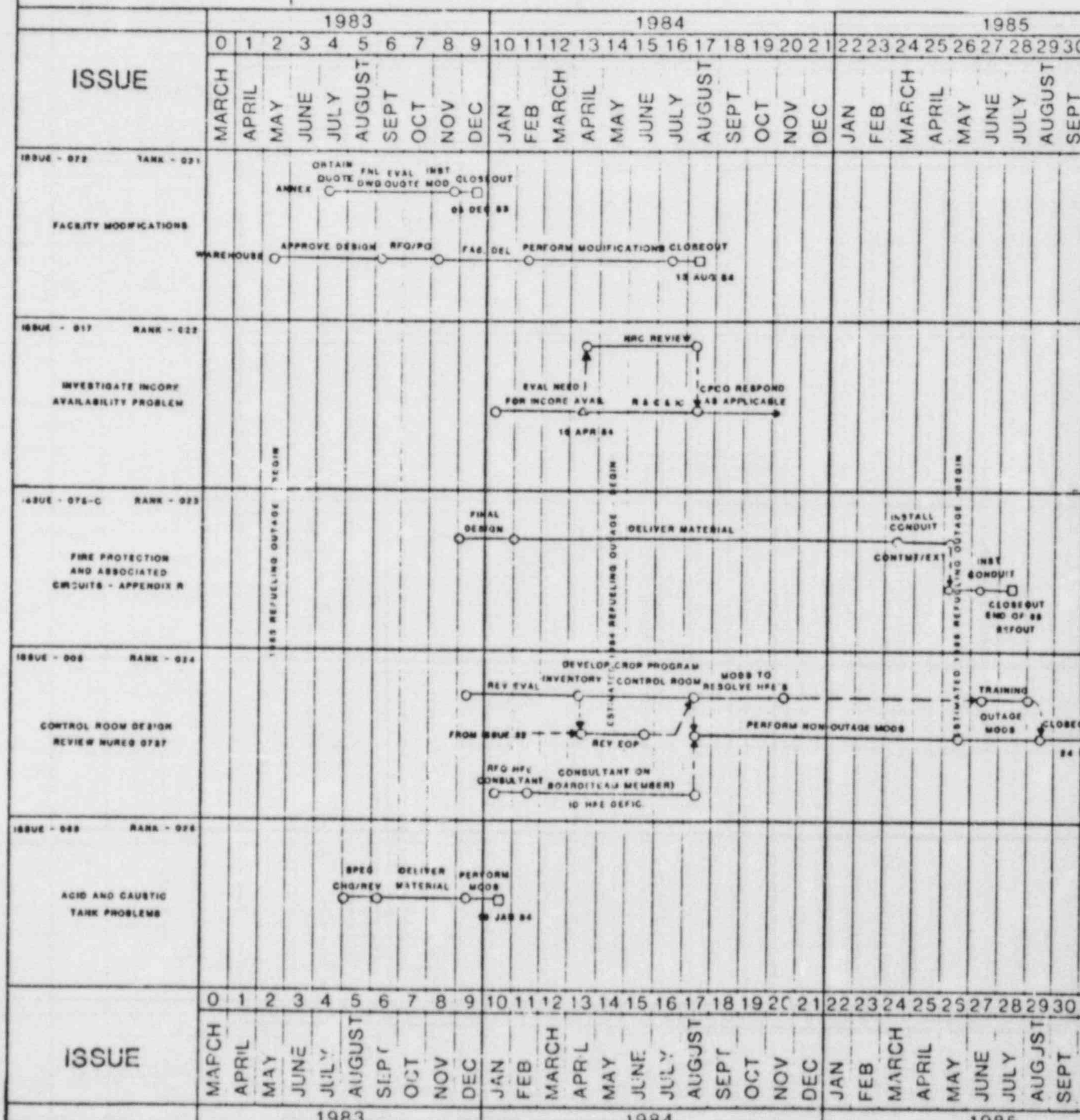

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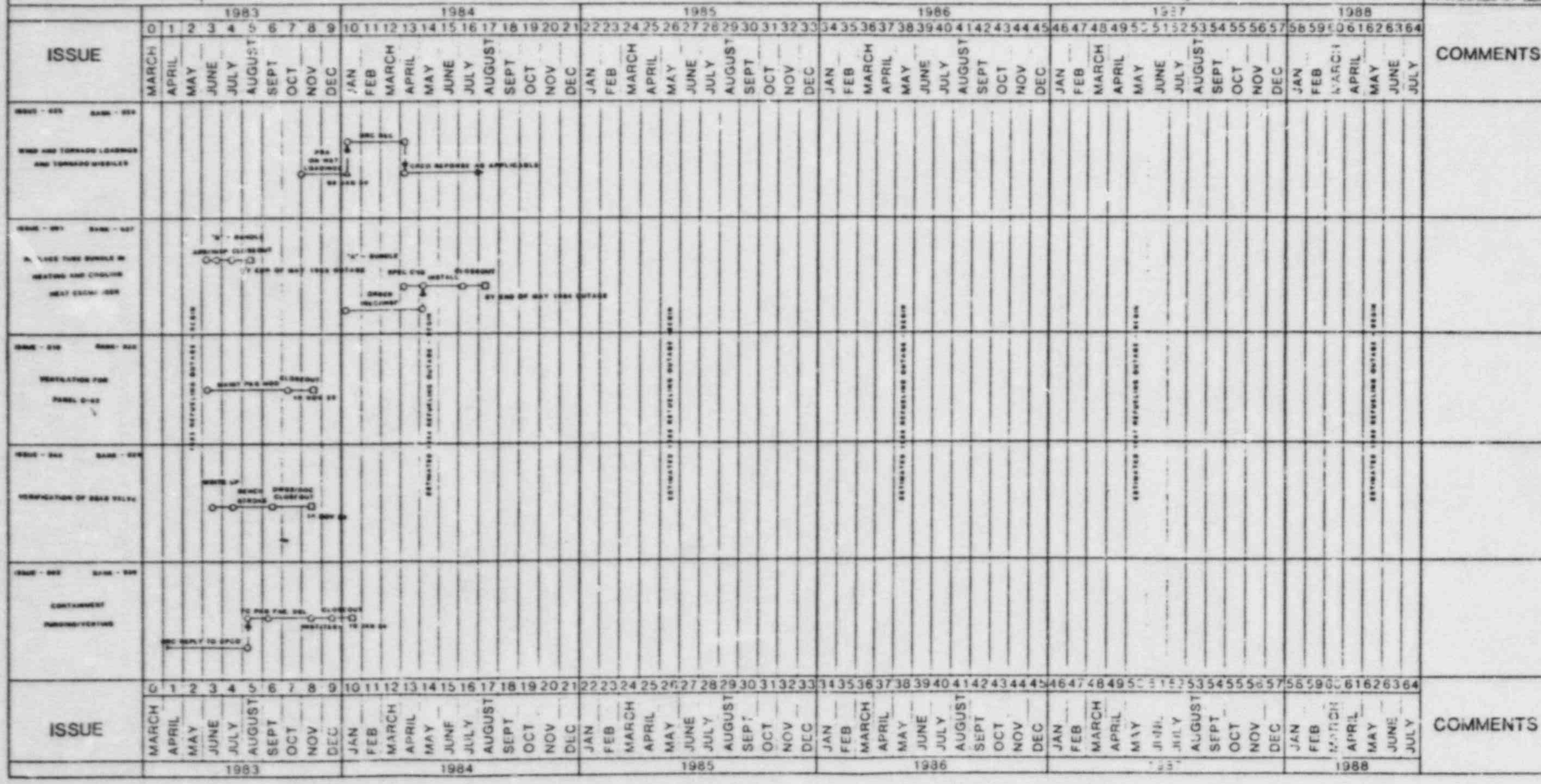

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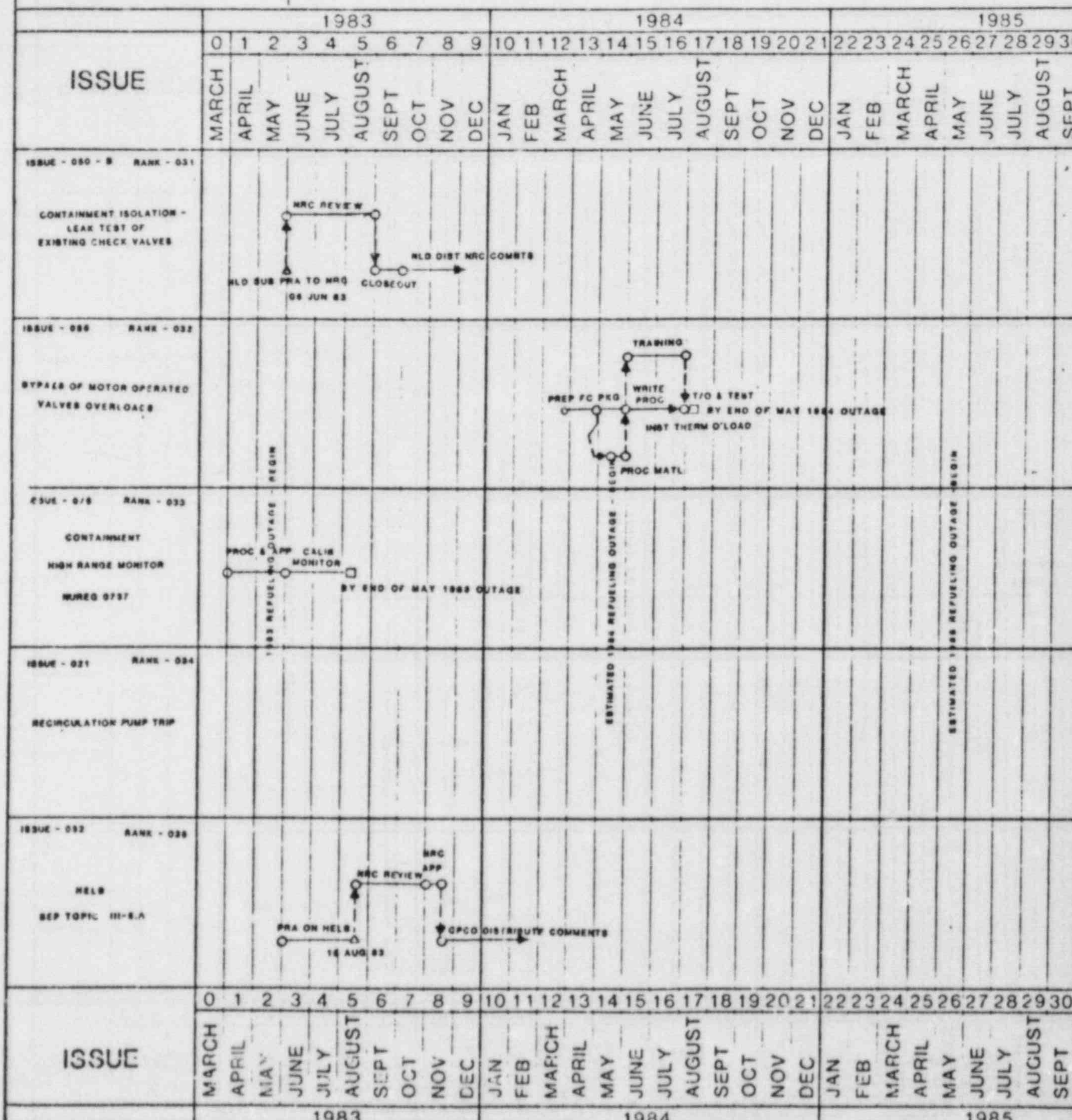

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CONSUMERS POWER COMPANY
BIG ROCK POINT PLANT
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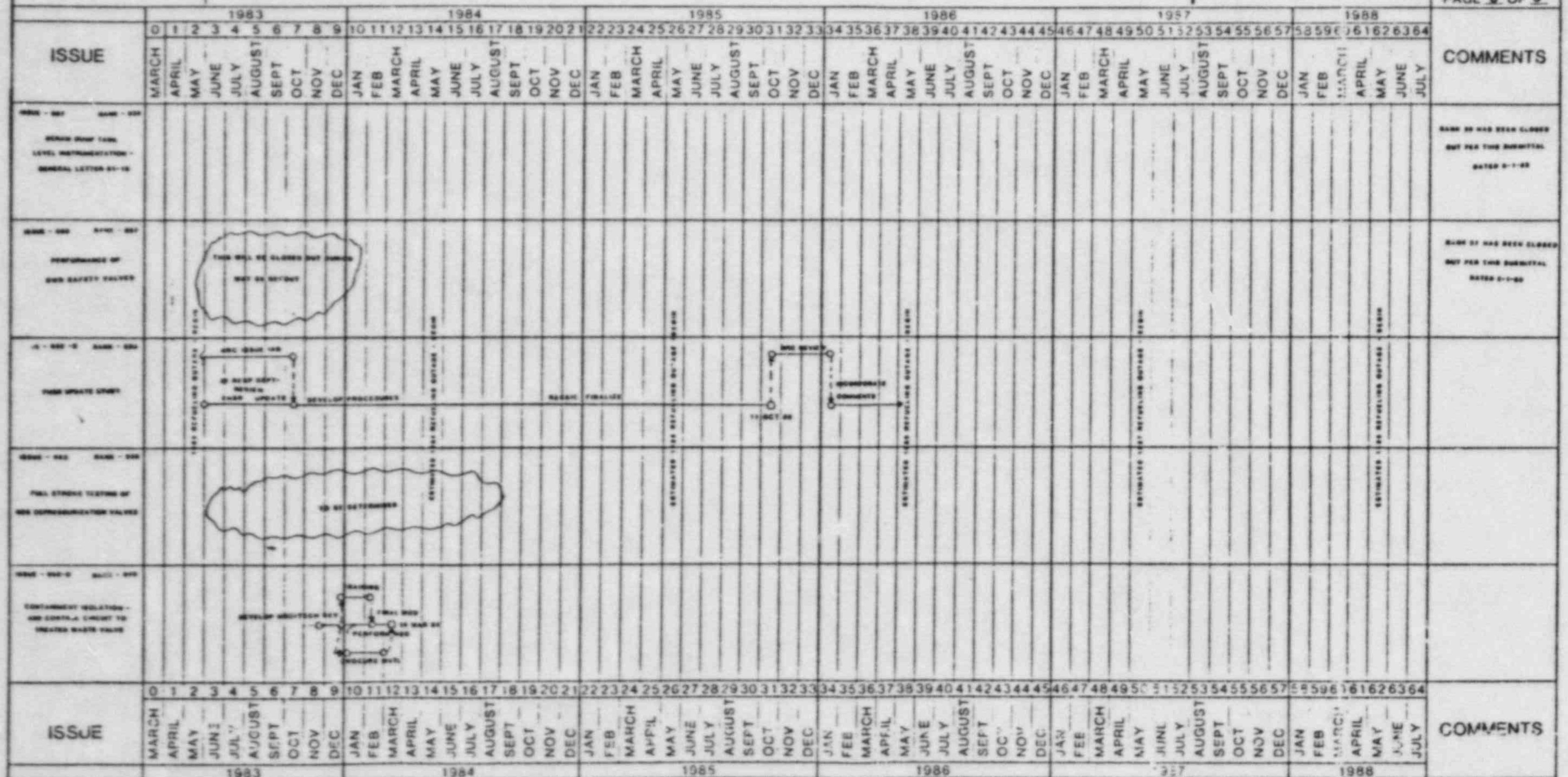
PAGE 8 OF 9



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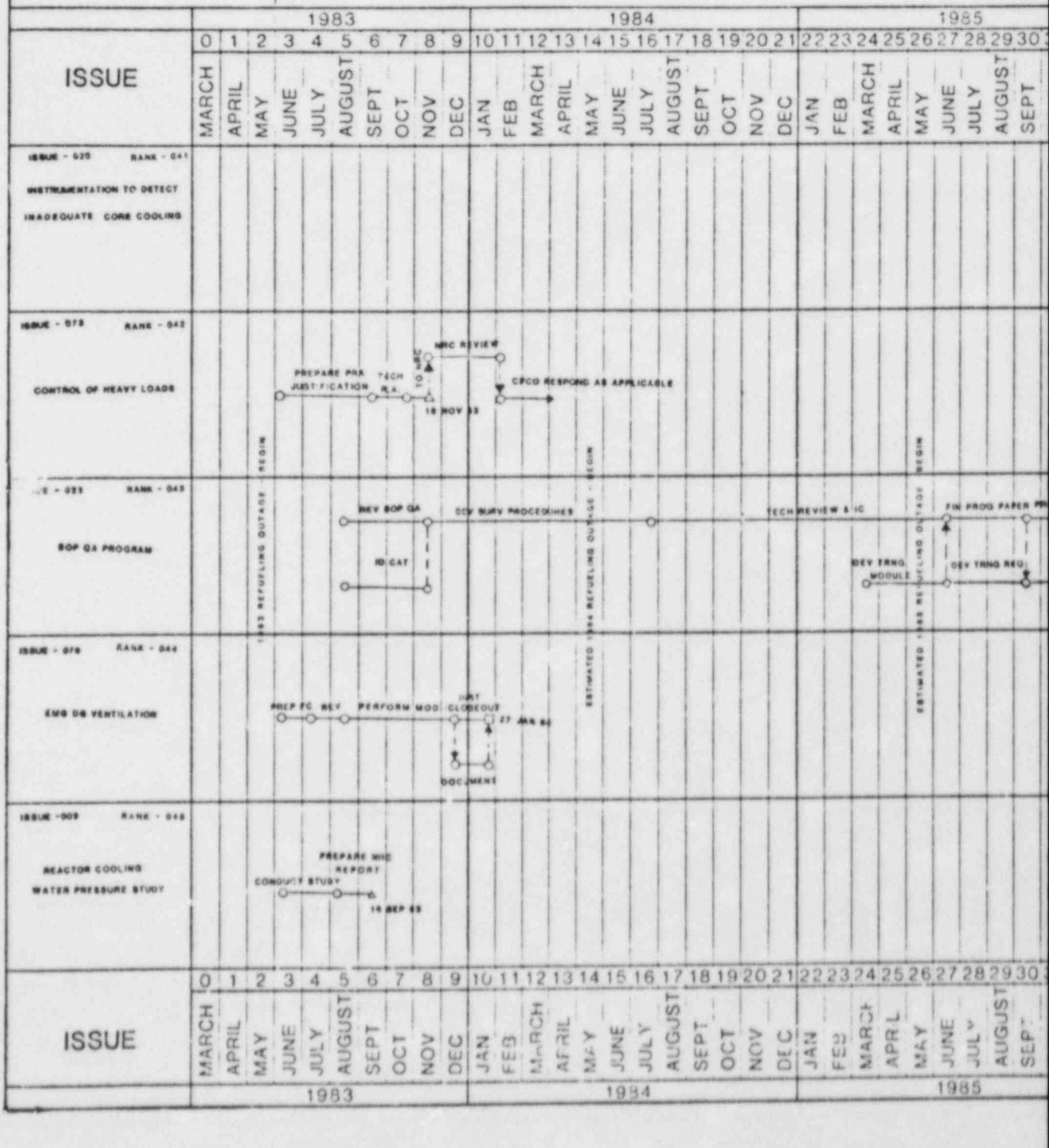

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PAGE 9 OF 9

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Consumers Power Company
Big Rock Point Plant
Docket 50-155

INTEGRATED ASSESSMENT OF OPEN ISSUES AND SCHEDULE FOR ISSUE RESOLUTION (INCLUDING ENVIRONMENTAL EQUIPMENT QUALIFICATION AND GENERIC LETTER 82-33 ISSUES)

June 1, 1983

Attachment No. 6

Milestone Summary
from Living Schedule

4 pages

Attachment 6

BIG ROCK POINT PLANT
MILESTONE SUMMARY
FROM LIVING SCHEDULE

RANK/ ISSUE	ISSUE DESCRIPTION	CPCo COMMITMENT DATE (□)	DATE CPCo WILL ISSUE A COMMITMENT DATE (Δ)	COMMENTS	CROSS REFERENCE TO DETAILED PLANS (END ACTIVITY)
001-082	RDS DEPRESSURIZATION VALVES		19JAN84		108200122
002-075A	ALTERNATE SHUTDOWN SYSTEM - APPENDIX R	END OF MAY 86 REFOUT			107501127
003-011	TURBINE BY-PASS VALVE EHC		07NOV83		101100154
004-036	ELECTRICAL EQUIP QUAL	1-30SEP 83	2-28FEB84 3-30 JUN 84	1-FMEA-REPORT 2-JCO'S/COMPLETE INPLEM 3-AGING PROGRAM	103601125 103602125 103603136
005-016	SECONDARY SYS INSTAB	03MAY84			101600147
006-014	SEISMIC DESIGN CONSID	08JUN84			101400146
007-032	EOP'S-NUREG 0737	18NOV83 06APR84		PROCEDURE GENERATION PKG.EOP'S IMPLEMENTED	10320152 103200176
008-054	PLANT SHIELDING - NUREG-0737		22AUG83		105400633
009-018	HIGH PRESSURE RECYCLE	06APR84			101800152
010-050A2	CNTMT ISOL - ON LINE TEST OF MSIV		12MAR84 19AUG87	TEST PROCEDURE FINAL REPORT	105001442 105001472
011-057	CNTL ROOM HABIT NUREG 0737		27 JUL83		105700632

BIG ROCK POINT PLANT
MILESTONE SUMMARY
FROM LIVING SCHEDULE

RANK/ ISSUE	ISSUE DESCRIPTION	CPCo COMMITMENT DATE (□)	DATE CPCo WILL ISSUE A COMMITMENT DATE (△)	COMMENTS	CROSS REFERENCE TO DETAILED PLANS (END ACTIVITY)
012-008	SINGLE CHANNEL RESET	END OF MAY 83 REFOUT		TEST(S)	100800143
013-085	CNTMT OVERPRESSURIZATION	END OF MAY 84 REFOUT			108500133
014-022A	ORGANIC MATERIALS	15DEC83		REPORT ON MATERIAL PROGRAM	1022004461
015-048	CLEANUP DEMIN PUMP REPL		19JAN84		104800136
017-004	STACK GAS MONITORING	09JAN84		IN-SERVICE DATE	100400124
018-017	PCS ISOLATION	END OF MAY 84 REFOUT			101700147
019-084	SCRAM DUMP TANK VALVES LACK OF REDUNDANCY		19JAN84		108400122
020-002	ACID LINE EXTENSION	19JAN84			100200145
021-072	FACILITY MODIFICATION ON ANNEX & WAREHOUSE	05DEC83 13AUG84		ANNEX- PDS (TRM) WAREHOUSE MOD'S	107201145 107202173
022-077	INVEST INCORE AVAIL		16APR84	WAITING ON CONNECTORS	107700137
023-075C	FIRE PROTECTION AND ASSOC CIR	END OF MAY 85 REFOUT			107503173
024-005	CONTROL RM DESIGN REVIEW NUREG 0737	24OCT85		INCLUDES SPDS	100500148
025-069	ACID & CAUSTIC TANK PROBLEMS	19JAN84			106900127

BIG ROCK PO...T PLANT
MILESTONE SUMMARY
FROM LIVING SCHEDULE

RANK/ ISSUE	ISSUE DESCRIPTION	CPCo COMMITMENT DATE (□)	DATE CPCo WILL ISSUE A COMMITMENT DATE (△)	COMMENTS	CROSS REFERENCE TO DETAILED PLANS (END ACTIVITY)
026-025	WIND&TORNADO LOADINGS AND TORNADO MISSILES		09JAN84	PRA	102500442
027-001	REPLACE TUBE BUNDLE IN HTG & CLG HEAT EXCHANGE	END OF MAY83 REFOUT END OF MAY84 REFOUT		B-BUNDLE A-BUNDLE	100101125 100102126
028-010	VENTILATION FOR PANEL C-52	18NOV83			101000133
029-044	VERIF OF BS&B VALVE	14NOV83			104400135
030-063	CONTMT PURGING/VENTING	16JAN84			106300138
031-050B	CONTMT ISOLATION LEAK TEST CHECK VALVES		06JUN83		105002442
032-086	BYPASS OF MOTOR OPER VALVE OVERLOADS	END OF MAY 84 REFOUT			108600136
033-076	CONTMT HIGH RANGE MONITOR NUREG 0737	END OF MAY 83 REFOUT		PERFORM CALIBRATION	107600112
035-052	HELB - SEP TOPIC III - 5.A		15AUG83		105200442
037-080	PERFORMANCE OF BWR SAFETY VALVES	END OF MAY 83 REFOUT			108000134
038-035B	FHSR UPDATE STUDY	11OCT85			103500426
039-083	FULL STROKE TESTING RDS DEPRESS VALVES			TO BE DETERMINED	108300143
040-050D	CONTMT ISOLATION TREATED WASTE VALVE ADD CONTROL CIRC	16MAR84			105004127

BIG ROCK POINT PLANT
MILESTONE SUMMARY
FROM LIVING SCHEDULE

RANK/ ISSUE	ISSUE DESCRIPTION	CPCo COMMITMENT DATE(□)	DATE CPCo WILL ISSUE A COMMITMENT DATE(△)	COMMENTS	CROSS REFERENCE TO DETAILED PLANS (END ACTIVITY)
042-073	CONTROL OF HEAVY LOADS		18NOV83		107300142
043-023	BOP QA PROGRAM	16DEC85			102300135
044-070	EMERGENCY DG VENTILA-TION	27 JAN84			107000145
045-009	REACTOR COOLING WATER PRESSURE STUDY		16 SEP 83		100900132

APPENDIX I

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
COMMENTS ON DRAFT NUREG-0828
AND STAFF RESPONSE

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

November 22, 1983

Honorable Nunzio J. Palladino
Chairman
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Dr. Palladino:

SUBJECT: ACRS REPORT ON THE EXPANDED SYSTEMATIC EVALUATION PROGRAM INTEGRATED PLANT SAFETY ASSESSMENT OF THE BIG ROCK POINT PLANT

During its 283rd meeting, November 17-19, 1983, the Advisory Committee on Reactor Safeguards reviewed the results of the Systematic Evaluation Program (SEP), Phase II, as it has been applied to the Big Rock Point Plant. This matter was discussed also during subcommittee meetings in Traverse City, Michigan on September 20-21 and in Washington, D.C. on November 7, 1983. During our review, we had the benefit of discussions with representatives of the Consumers Power Company (Licensee) and the NRC Staff, and comments from members of the public. We also had the benefit of the documents referenced.

The Big Rock Point Plant was constructed in 1960-62 and began commercial operation in December 1962. It received a full-term operating license in May 1964. It is the second oldest commercial nuclear power plant still operating in the U. S and, at a rated electrical output of 75 MWe, it is the second smallest.

The SEP evaluation of the Big Rock Point Plant initially was carried out in the same manner as for the plants previously reviewed. Of the 137 topics to be addressed in the SEP, 29 were not applicable to the Big Rock Point Plant and 23 were deleted because they were being reviewed generically under either the Unresolved Safety Issues (USI) program or the Three Mile Island (TMI) Action Plan. Of the 85 topics addressed in the NRC Staff's review, 53 were found to meet current NRC criteria or to be acceptable on another defined basis and two were resolved during the review. We have reviewed the assessments and conclusions of the NRC Staff relating to these topics and have found them appropriate.

The 30 remaining topics involved 53 issues relating to areas in which the Big Rock Point Plant did not meet current criteria. These issues were addressed by the Integrated Plant Safety Assessment and various corrective actions were considered or proposed by the Licensee and by the NRC Staff. However, during this review of the SEP-related issues, the Licensee requested that the Integrated Assessment be expanded to include many of the pending licensing actions for Big Rock Point that were related to requirements outside the scope of the SEP review. These additional issues included many of the USI and TMI Action Plan items that had been excluded earlier from the SEP review as well as other multi-plant actions. The list of items submitted by the Licensee included modifications intended to improve reliability or availability or to reduce occupational exposures. For the most part, these modifications were not "safety related" but some were considered by the NRC Staff to be "important to safety." The 43 issues proposed by the Licensee were assigned priorities based primarily on a plant-specific probabilistic risk assessment (PRA) performed by the Licensee and his contractor.

The NRC Staff agreed to include these issues in the expanded assessment proposed by the Licensee and, after a review of all pending licensing actions for the Big Rock Point Plant, added 16 issues to the list. The total number of issues considered in the Integrated Plant Safety Assessments by the Licensee and the NRC Staff was 112.

For 50 of the 112 issues included in the Integrated Assessment, the NRC Staff concluded that no backfit is required. For 16 of the remaining issues, changes to the Technical Specifications or procedures were recommended by the NRC Staff and agreed to by the Licensee.

For 14 issues, the Licensee has proposed hardware backfits for their resolution and the NRC Staff has found these proposals acceptable. Four of these issues were related to SEP topics; the others were from the expanded list of non-SEP topics, and three of these involve modifications that are not "safety related."

As has been the case for the other plants in the SEP, the Integrated Assessment has not been completed for a number of issues, for which the Licensee has agreed to provide the results of studies, analyses, and evaluations needed by the NRC Staff for its assessments and decisions. All of these issues are of such a nature that hardware backfits may be required for their resolution. The resolution of these issues will be addressed by the NRC Staff in a supplemental report.

Many of the issues still being evaluated by the Licensee relate to the effects of extreme environmental phenomena, especially earthquakes and tornadoes, since the Big Rock Point Plant was not designed to resist these phenomena at the levels that would be required by current criteria.

The Licensee's proposal to upgrade the seismic resistance of the Big Rock Point Plant to the level of 0.12g proposed by the NRC Staff is notably different than what has been required or done for the other SEP plants. The Licensee has indicated that, for a plant of the size and age of Big Rock

Point, it is not economically feasible to perform the analyses required to demonstrate seismic capability and quantify analytical uncertainty. Instead, the Licensee has proposed to evaluate the seismic resistance of equipment important to safety using a combination of probabilistic and deterministic methods. Then, on the basis of this evaluation, the Licensee proposes to selectively upgrade the "weak links" in the systems and structures required to mitigate accidents that would be expected to result from seismic events. The NRC Staff has concluded that this approach is reasonable for the Big Rock Point Plant and, if properly executed, it would provide adequate seismic resistance. We agree.

Use was made of a limited PRA in connection with the NRC Staff's evaluations. Since a plant-specific PRA was available for the Big Rock Point Plant, the technique used was somewhat different than that used for other plants in the SEP for which a plant-specific PRA was not available. The chief difference was that the NRC Staff was able to assign priorities based on the reduction in doses that could be attributed to the proposed modification. We believe that the NRC Staff's use of PRA was appropriate and that suitable use was made of the results.

Our conclusions regarding the SEP review of the Big Rock Point Plant are as follows:

1. The actions taken thus far by the NRC Staff in its expanded assessment of the Big Rock Point Plant are acceptable.

2. We will expect to review the results of the evaluations that are being made and the proposals and schedules for modifications that will result from them.

3. In evaluating the seismic capability, as noted above, assessment of the seismic capacity of weak links will prove to be complex, and care will be required to accomplish an appropriate degree of conservatism (adequate margins) in the light of uncertainties in such capacities. The ACRS expects to review this aspect in detail as part of its evaluation as to whether an acceptable level of risk exists following the modifications.

Dr. William Kerr did not participate in the Committee's review of this matter.

Sincerely,

J. J. Ray

J. J. Ray
Chairman

References:

1. Consumers Power Company, "Final Hazards Summary Report for Big Rock Point Plant," Volumes 1-2, dated November 14, 1961

2. U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, "Integrated Plant Safety Assessment, Systematic Evaluation Program, Big Rock Point Plant," USNRC Draft Report NUREG-0828, dated September 1983

3. Letter from Ms. Christa-Maria, Subject: Big Rock Point Plant SEP, prepared for ACRS Subcommittee meeting September 21-22, 1983

4. Letter from Martha Drake and Gerald A. Drake, Subject: Big Rock Point Plant, dated October 1, 1983

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JAN 26 1984

Mr. Jesse C. Ebersole, Chairman
Advisory Committee on Reactor Safeguards
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Ebersole:

In a letter to Chairman Palladino dated November 22, 1983, the ACRS presented its views on the Systematic Evaluation Program as applied and presented in the draft Integrated Plant Safety Assessment Report (IPSAR) for the Big Rock Point Plant. In summary, that letter supported the staff's actions taken thus far in the expanded integrated assessment; expressed the ACRS desire to review the results of ongoing evaluations and the proposals and schedules for modifications resulting from them; and expressed the ACRS desire to review the seismic upgrade program in detail.

The staff will revise the draft IPSAR to reflect the additional information provided by the licensee, respond to the recommendations and comments made by the staff's consultants, and incorporate the licensee's integrated implementation schedule. Subsequently, the staff will issue a supplement to the IPSAR describing the results of the ongoing evaluations. The schedule for the supplement will be determined following the submittal of the licensee's integrated schedule. The staff will present the results of the ongoing evaluations and the resulting implementation schedules to the Committee following the issuance of the supplement.

Sincerely,

(Signed) William J. Dircks

William J. Dircks
Executive Director for Operations

*See previous tissue for concurrences.

SEPB:DL	SEPB:DL	ORB#5:PM	ORB#5:PM	AD:SA:DL	D:DL
RScholl:dk*	CGrimes*	REmch*	DCrutchfield*	FMiraglia*	DEisenhut
1/9 /84	1/9 /84	1/11/84	1/11/84	1/11/84	1/19/84
D:NRR	EDO				
HDenton	WDircks				
1/ /84	1/ /84				

APPENDIX J

CONSULTANTS' COMMENTS ON DRAFT NUREG-0828 AND STAFF RESPONSE

Future Resources Associates, Inc.

2000 Center Street Suite 418 Berkeley, CA 94704 415-526-5111

3 November 1983

Mr. Christopher I. Grimes
Systematic Evaluation Program Branch
Division of Licensing, NRR
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Mr. Grimes:

This letter is my report to you on my review of Draft Report NUREG-0828, "Integrated Plant Safety Assessment, Systematic Evaluation Program, Big Rock Point Plant." I have carried out this review under contract number NRC-03-83-099.

INTRODUCTORY COMMENTS

I found the draft report very easy to review. It is well written, has clear cross-references among its various sections and appendices, and is well documented in terms of references to material outside of the report itself, In particular, the cross-linkages among different technical topics that are related are handled very well.

The review was made slightly more complicated than reviews of earlier SEP assessments because Big Rock Point is a unique, one-of-a-kind plant with some configurations and design features unfamiliar to me. I wasn't always sure that the discussion made sense, because I wasn't (still am not) totally familiar with Big Rock Point's idiosyncracies. For this reason, there were a few (but only a few) places where I could not judge for myself whether the decision taken was appropriate. These instances were minor in importance, and my overall review has not been affected by this problem.

I believe that the overall methodology is appropriate for accomplishing the objectives of the Systematic Evaluation Program. I will provide specific comments about this below. As an overview, I believe that the approach of analyzing specific issues, utilizing probabilistic methods where appropriate, and studying the operating experience is, when taken as a whole, the proper way to carry out the SEP integrated assessment.

KEY CONCLUSIONS

I have arrived at a few key conclusions after reading and studying the draft integrated assessment and its backup material:

1) I have concluded that the Big Rock Point Plant complies nearly fully with all of the current NRC safety regulations. For a few issues, the compliance is with the intent of the regulation although not with the specific letter of the regulation. I believe that the SEP integrated assessment has done a very fine job of pointing out and assessing these few issues, in terms of the significance that they pose for safety. My overall judgment includes a few assumptions on my part as to how unresolved issues will turn out ultimately. My judgment is that those few deviations are not, on balance, very important to safety.

2) I very strongly endorse the methodology of this integrated assessment in which the list of SEP issues is considered together with other pending regulatory actions such as generic issues, TMI Action Plan items, and items suggested by the licensee. In my reviews of earlier SEP integrated assessments, I called for just such a broader integrated assessment, and am highly pleased that for Big Rock Point this has been accomplished. I believe that this approach gives maximum return for the investment in resources (manpower, funds) made by both licensee and staff in carrying out the assessment. Judgments are always better when made in a broader context -- the broader the better.

3) I believe that the general purpose of the SEP reviews is broader than simply to ascertain whether the older plants meet today's licensing criteria or are acceptable on some other defined basis. In my view, the purpose has been (and properly so) the discovery of whether the level of safety achieved by the older plants is reasonably consistent with the level of safety that the NRC is seeking in its regulations. In this regard, the draft SEP report for Big Rock Point contains several places where the text clearly implies that NRC's present judgment on this point is that BRP has attained adequate safety levels. For example, in more than one place in the text the rationale for allowing a particular deviation from existing regulations is that the public risk is low due to the small size and remote site of BRP. I agree with this line of reasoning myself, and would make the same judgment myself. However, there is evidence of another kind from the plant's own PRA: specifically, the best estimate for core-melt frequency in that PRA is higher than that calculated in other PRAs recently performed. While off-site risk is low, core-melt likelihood is, by itself, an important measure of plant safety performance. What I am driving at here is the clear need, in my opinion, for the final version of this report to address this issue: specifically, to address why it is that the calculated core-melt frequency in the utility-sponsored PRA does not override other judgments as to the adequacy of Big Rock Point's achieved safety level. (I am personally comfortable, but I am also personally aware of some other individuals within NRC, including Commissioner-level, who have concerns.)

4) I believe that the existence of the plant-specific PRA has enhanced the usefulness and quality of the BRP integrated assessment considerably. It is fortunate that the utility sponsored the PRA and completed it prior to the start of the SEP review. In my view, a key lesson I have learned from this assessment is that the proposed ISAP effort will be enhanced very much if plant-specific PRAs are part of the program.

5) My general impression from the draft report is that plant management at Big Rock Point is effective and competent. First, this impression emerges from reading the report generally. Second, the management took the initiative of proposing the full integrated assessment that includes the TMI issues, the generic issues, and issues desired by the management. Third, the BRP management has begun to implement a 'risk management' program, based on the lessons from their PRA, that is out in front of the rest of the industry. Finally, the cooperation of the management in addressing and negotiating the SEP issues seems to be excellent, at least as that issue emerges from the text.

REVIEW OF OPERATING EXPERIENCE (APPENDIX F)

I learned a lot from studying the review of operating experience. The detail was helpful. I've now reviewed several of these documents, and it is fair to note that when I began to study the Appendix F material I had a bit of trepidation ("Oh, well, here's another one of these things"). But when I got into the text I found the information interesting and useful.

My general conclusion is that Big Rock Point has performed well -- indeed, I should say that it has done remarkably well under its peculiar circumstances: a small, one-of-a-kind plant. Not much in the way of safety concern has arisen in the operating record as far as I can judge. The time trend is pretty flat as well, when I study the potentially important issues, although Figure 4.3 (page F-51) gives a different impression in its plot of 'reportable events' over the years. Some of the issues discussed have now become obsolete, or have been solved, leaving little that is of ongoing concern from the operating record.

I note, for example, that since the installation of an additional (46 kV) line offsite some years back, the threat of total loss of offsite power from the loss of the 138-kV line is now absent. Also, the fuel failures discussed in the report are a thing of the past, especially since the 'experimental' program is now over.

I learned from this Appendix, as well as other material in the SEP assessment, that in some key areas the Big Rock Point plant is overdesigned -- or more precisely, has extra redundancy or backup. For example, the containment size is apparently much greater than one would expect considering the small power level of the reactor. Also, there are two 100% emergency condensers so that losing one doesn't compromise decay heat removal. There are other examples as well.

One of the interesting things I learned from reading Appendix F, which is not directly relevant to the issue at hand, is that from ground-breaking to criticality, the construction time of Big Rock Point was 29 months (see page F-32). Maybe there's a lesson in that for somebody.

I studied the six 'significant events' identified in the review (page F-77 ff.). None but the containment integrity violation looks very troublesome. That event is obviously a sign of a difficulty that I expect has been cleared up since it happened (1974). None of the other events bother me very much.

From my review of Appendix F, I conclude that the general operating history of Big Rock Point has been mostly uneventful. There is little to feed into the integrated SEP assessment from the operating experience record. That's good news indeed.

THE PRA ANALYSIS (APPENDIX D)

Appendix D is an application of PRA methods to study certain of the issues considered in the integrated assessment. About half of all the issues in the integrated assessment were studied using probabilistic methods, although this fraction depends on how you count issues.

Fortunately, a full plant-specific PRA exists for Big Rock Point. The PRA analysis of Appendix D, supported by the NRC staff for use in the SEP assessment, gained substantial benefit from the full-scope PRA already accomplished. The overall benefit of the perspective provided by these analyses is very great, in my view.

The methodology taken by the PRA analysts is appropriate. They first studied each issue to ascertain which safety functions or systems are affected. Then they studied which accident sequences of importance might be affected by the safety functions or systems. This is the best way to utilize the existing PRA in studying a particular issue.

I am not totally enamored with the 'averted dose' approach, in which the effect of a particular action is calculated using the yardstick of the expected value of doses (person-rem per year) that would be averted by the action. The reason is that this numerical yardstick can carry with it in some people's minds a precision that the PRA methods do not have in fact. Another reason is that there are other end-points besides the doses cited that might be of concern. (Of course, at Big Rock Point we now recognize that offsite prompt radiation fatalities will be zero, or miniscule, because of the plant size and site.) Despite this reservation, I believe that the 'averted dose' figures do give some useful insights, and I do not think that they were abused in this SEP review effort. So my overview comment is that I am lukewarm but not opposed to this approach.

It is important to point out that the text of Appendix D does contain (page D - 4) a well-written warning as to what the applicability is -- and is not -- of the PRA insights.

The Appendix is generally well written. I was able to follow the analyses in adequate detail, and to understand the arguments. This is a complement, since not all PRA documentation is scrutible.

Specific issues covered in Appendix D will be discussed below, as appropriate, in my discussion of the issues covered in the integrated assessment.

COMMENTS ON SPECIFIC ISSUES

I will make comments on the treatment of a few specific issues, with no pretense of comprehensive coverage. Although I examined all of the issues in enough detail to understand them, I will only comment where it is warranted. If no comment is made, it is fair to assume that I concur in the situation as described.

Section 4.5 (Topic III-2), Wind and Tornado Loadings
The staff's recommendations under 4.5.1 are excellent, in that they provide three options to the licensee for resolving the issue that some structures do not meet current licensing criteria. Allowing the licensee to use a risk-based approach where it can be justified is an excellent approach. Under section 4.5.5 (load combinations), I think that insisting on 10^{-4} and 10^{-5} windspeeds at the upper 95% confidence level may be too severe a requirement. I would recommend backing off to, say, a median (50 %) confidence level. Otherwise, the approach in 4.5.5 is acceptable.

Section 4.9 (Topic III-4.A), Tornado Missiles
The last paragraph of the write-up says that the licensee proposes to evaluate the damage probability from tornado missiles in conjunction with his PRA. What tornado missile spectrum will he use ? I must assume that he will use the licensing-basis missile spectrum, although the text does not say; but I could also assume that he might generate some other spectrum of potential missiles if he could defend it. If the licensee proposed to do the latter, I would defend that approach as acceptable.

Section 4.10 (Topic III-5.A), Line Breaks
In the last paragraph, the licensee is said to believe that the probability of a high-energy line break is small enough that corrective actions will not be cost effective. I wish to warn NRC that a careful analysis of the uncertainties in the PRA numerical conclusions is called for before this conclusion can be accepted; in particular, there might be some reasonable chance that the 'correct' answer lies considerably higher in value than the best estimate value given, which could obviate the conclusion.

Section 4.12 (Topic III-6), Seismic Design Considerations
The text discusses identifying 'weak links', which are the cut sets (that is, accident sequences) with the highest likelihood of leading to an unfavorable end-state for the reactor. However, there is no discussion of whether any cut-off will be used. For example, perhaps even the 'weakest' of the 'weak links' is actually adequately safe, in the sense that its probability and consequences are acceptable. I am puzzled by the write-up.

Section 4.13 (Topic III-7.B), Load Combinations
There is good reasoning on the part of the staff in treating this topic. In particular, the idea of treating all the issues collectively is in exactly the correct direction.

Section 4.16 (Topic V-5), RCPB Leakage Detection
The long paragraph at the bottom of page 4-16 of the text is muddled and hard to follow. I couldn't follow it as well as I would like and suggest that it be re-written so that the rationale for the staff position emerges clearly.

Section 4.20 (Topic VI-4), Containment Isolation System
In both section 4.20.5 (MSIV) and 4.20.6 (closed systems) the staff has used PRA insights well. Under 4.20.6, the licensee apparently does not agree that a periodic inspection procedure is worthwhile. Is there still room for negotiation on this one, or has the staff position prevailed ? My own view is that it depends on how much effort is really involved.

Section 4.22 (Topic VII-1.A), Isolation of RPS System
The PRA analysis in Appendix D is excellent.

Section 5.3.1, RDS Valve Reliability
Item 5.3.1.1 seems to be very important in a safety sense. I am quite surprised that the licensee's calculation shows such a high likelihood of a failure leading to a blowdown (6.7×10^{-3} per year). The risk to personnel from such a blowdown is obviously high. The concluding paragraph states that if the leakage can be reduced significantly "compared to the cost", suitable fixes will be done. What if the cost is too high ? What is the staff position in that eventuality ?

Under 5.3.1.3 (full stroke testing), it is stated that continued operation is justified by the "low likelihood of mechanical failures". How is this known ?

Section 5.3.10, RCS Isolation
This is apparently an important safety issue, and the use of PRA in assisting its resolution is excellent.

That completes my review of the Big Rock Point SEP integrated assessment report (NUREG-0828). My overview comment is that the staff document is excellent, and that the concept of integrating the SEP issues with other regulatory issues is also excellent.

Sincerely yours,

Robert J. Budnitz

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November 14, 1983

Mr. Christopher I. Grimes
Project Manager, Systematic Evaluation
Program Branch
Mail Stop 516
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

REF: Integrated Plant Safety Assessment
Big Rock Point Plant
Systematic Evaluation Program

Dear Mr. Grimes:

This letter is my technical evaluation report on the Big Rock Point Plant Integrated Plant Safety Assessment, as given in the draft report NUREG-0828. It fulfills the requirements of the seventh work assignment (Big Rock Point) of Revision 1 of the project, "Consultant Services, Dr. J. M. Hendrie to Review SEP Integrated Plant Safety Assessment Report," FIN A-3367, B&R No. 20-19-20-21-1.

CONCLUSIONS

The Draft Integrated Plant Safety Assessment Report on the Big Rock unit is consistent in treatment with previous reports of the Systematic Evaluation Program. The scope of the report is more extensive than for previous reviews, due to the inclusion, at the licensee's request, of essentially all other outstanding regulatory issues of any significance as well as some plant improvement matters originated by the licensee. The Big Rock review has been carried out in accordance with established program directives. It supports my previous conclusion that the SEP is fulfilling the intent of the Commission when it authorized Phase II of the program.

Detailed comments on the results of the integrated assessment process are given below. In general, I find the staff recommendations for backfitting, or for not requiring backfitting, to be reasonable and appropriate and the bases for those recommendations to be adequate. For two topics, Section 4.23, monitoring of dc power systems, and Section 4.28, main steam line break radiological consequence, the summary information in the draft report seemed to me to allow of some different conclusions. I did not have time to examine the full files on these subjects, however, and simply leave my questions on them for staff consideration.

The inclusion in the SEP review of other regulatory matters currently affecting Big Rock, and of significant plant improvement projects, allows a coordinated approach to plant changes. Priorities can be assigned, manpower scheduled, and the various jobs done without needless stops and starts. I have been advocating this sort of extended role for the SEP and am pleased to see it in action, in this case at the request of the licensee. Judging by the discussions in Section 5 (Non-SEP Topic Reviews), the process is working fine and should be a benefit to both staff and licensee.

The licensee's probabilistic risk assessment (PRA) study of Big Rock is useful as a gauge for the significance of various topics and as a base for the limited PRA exercises of the staff's consultants. It provides valuable insights into safety issues that would not be available otherwise.

Some of the staff recommendations for Big Rock at this stage of the SEP review are for further analysis and evaluation by the licensee. The number of such open items, incidentally, is markedly smaller for Big Rock than for earlier SEP reviews. The results of these analyses and evaluations will require some further decisions by the staff as to whether or not backfiting of some kind is needed. These further decisions should be made on the same integrated assessment basis as those given in the draft report.

Also, a number of the original 137 SEP safety topics are being treated generically under the Unresolved Safety Issue program, the Three Mile Island Action Plan program, or other regulatory generic programs such as implementation of Appendix I to 10 CFR 50. Most of these topics are not covered in the Big Rock SEP review in NUREG-0828. Resolutions of these topics that are specific to Big Rock will be needed eventually. The generic resolutions of these topics should be applied to Big Rock through the integrated assessment process.

DISCUSSION

THE STAFF SAFETY REVIEW

The intent of the SEP review is to examine a chosen plant against current licensing criteria and practices in 137 safety topic areas. These 137 topics are listed in Appendix A of the report. Where deviations from current criteria are found, there are a number of alternaives, or combinations of alternatives, that may be considered as a basis for acceptability. These include acceptance of the deviation because it does not significantly decrease the plant safety level, use of non-safety-grade systems to perform safety functions, administrative or procedural changes to enhance safety system reliability, augmented surveillance programs for the same purpose, and selected backfitting. Deviations from current criteria are acceptable if staff evaluations show that the plant would respond satisfactorily to the various design basis events and that the probability of those or the consequences are not significantly higher than for plants now being licensed in accordance with current criteria.

For Big Rock, the licensee requested that a number of other items be included in the staff's integrated assessment. These items include other regulatory matters such as Three Mile Island items, generic letter and IE bulletin items, and unresolved safety issue items. The items also include various plant improvement matters, some of which are safety-related, that the licensee wants to accomplish. By putting all of these matters, together with the SEP topics, under the same integrated review process the licensee can hope to get a more even-handed treatment of regulatory issues that takes account of the specific circumstances and resources at Big Rock. Also, agreements on priorities and schedules can be more easily reached in this framework.

The standard SEP review of Big Rock, based on the 137 SEP safety topics, is summarized in Sections 3 and 4 of the report. The extended review items, requested by the licensee, are summarized in Section 5 of the report.

In the standard SEP review, 52 of the 137 safety topics were deleted because they did not apply to Big Rock (the 29 topics listed in Appendix C) or because they are being covered by other staff groups on a generic basis (the 23 topics listed in Appendix B). The latter group of deleted topics is composed of Three Mile Island Action Plan items and unresolved safety issues. Some, perhaps a half-dozen, of these are covered in the licensee items in Section 5. The 52 deletions from the standard SEP review are appropriate and are consistent with other SEP reviews.

The 85 SEP topics reviewed for Big Rock resulted in staff judgments that the plant meets current criteria or is acceptable on some other defined basis for 53 topics. Two more topics were elevatd to that classification by modifications made by the licensee during the review. The remaining 30 topics were considered in the SEP integrated assessment process, to determine what actions should be taken to deal with the identified deviations from current criteria. The results of the integrated assessments for those 30 topics are given in Section 4 of the report.

The staff did not identify any safety issues requiring immediate acion. I agree that none of the identified deviations from current criteria are of "immediate safety significance".

COMMENTS ON THE INTEGRATED ASSESSMENT RESULTS - SECTION 4

4.1, 4.5, 4.8 Topics II-2.A, III-2, and III-4.A: These topics cover severe weather phenomena, wind and tornado loadings, and tornado missiles and pick up some items not considered in the original Big Rock design. The staff has adapted its standard SEP formulations for these topics, in part, at least, to allow the licensee to use his probabilistic risk assessment (PRA) for Big Rock. For the wind and tornado loadings, the PRA includes an evaluation of the maximum winds for which safe shutdown is assured, and the recurrence interval for that wind speed. The staff requires, in addition, evaluation on a cost-benefit basis of the measures needed to withstand winds at the SEP standard

10^{-4} and 10^{-5} intervals. This will bring Big Rock into line with other SEP plants, which is nice from the standpoint of uniform requirements, but does not give any credit for the relatively low power level of the Big Rock unit.

For tornado missiles, the requirement is to show the ability to shut down safely using equipment protected from missiles on the basis of the evaluations for wind speeds from the wind loadings topic. That is consistent with the practice for other SEP plants and is a reasonable approach.

4.2, 4.6, 4.7 Topics II-3.B, II-3.B.1, II-3.C, III-3.A and III-3.C: These are the flooding and high water level topics, including ultimate heat sink water supply and inspection of water control structures. Subject to some further consideration by the staff of shutdown capability in high and low water conditions, some touching up of the licensee's flood emergency plan, and formalization of water control structure inspections in plant procedures, these topics appear to be resolved on appropriate bases. I agree with the decision not to require periodic inspection of the buried intake line, in view of the risks to inspectors and the negligible safety benefit of inspection. [A minor editorial matter: on page 4-2, the short list near the top says ".... (PMS) from wave runup - 586.8 ft MSL," while the penultimate paragraph says ".... this estimate did not include the effect of wave runup."]

4.3 Topic II-4.B: The concern is with the possibility that a large solution cavity might be present or might be formed under the plant, leading to major foundation subsidence. There is no indication in the original test boring data that there is any such cavern under the plant; however, the Traverse Bay region does have such solution features. After review of reports from consultants on the matter, the staff concluded that it is unlikely that significant solutioning is going on or that there are already any large cavities under the plant. Big Rock has, after all, shown no untoward subsidence after 20 years. Therefore, the staff decided not to require any further investigation and closed the issue. I agree.

4.4 Topic III-1: Seismic and quality classifications. Quality standards in design and construction codes have been upgraded since Big Rock was completed. This topic looks at the differences. Big Rock seems to have substantially fewer problems of this kind than most SEP plants at this stage of the review. Piping and pressure vessels (the Class 1 stuff) need some extended fatigue analyses. The licensee has to define the cyclic loadings for these analyses: this will be done in connection with the seismic design topic and then the fatigue analyses will be completed. As is customary, the results will appear in an updated Final Safety Analysis Report, to be submitted within two years. The approach is consistent with other SEP reviews.

4.9 Topic III-4.B: Turbine missiles. In spite of its age, Big Rock may be the best plant in operation with regard to turbine missiles. The turbine is small (by nuclear plant standards); it has a one-piece rotor (the perfect solution to erosion and cracking around disc bores), and no safety-essential components within 25° of the turbine wheel planes. No wonder the staff concurred in a 7-year inspection schedule and no requirement for a redundant overspeed trip for the turbine. I would too.

4.10, 4.11 Topics III-5.A and B: These topics cover pipe breaks inside and outside containment, and the effects thereof on safety-related equipment. For pipe breaks inside containment, the licensee argues, via his PRA work, that the chance of a high-energy break that would cause core damage is low enough to be ignored. The staff is mulling that over. If the licensee's probability number (4.7×10^{-6}/yr) is in the right ball park and the leakage detection systems are adequate, I regard it as an acceptable proposition.

For pipe breaks outside containment, the issue seemed to come down to whether a medium-energy break could flood out both fire pumps in the screenhouse. Further review and a limited PRA by staff consultants suggest fire pump unavailability is dominated by mechanical failures, rather than flooding possibilities, and anyway the plant can be safely shut down if water can be gotten from onsite wells into the demineralized water system with the screenhouse flooded. Since that is required to settle the high water issues, it also should settle this topic.

4.12, 4.13 Topics III-6 and III-7.B: Seismic design, design codes and criteria, load combinations, and reactor cavity design criteria. Big Rock was built in the happy days before the present seismic analysis requirements. To backfit all that analysis now to the as-built plant would be unreasonably expensive and time-consuming, says the licensee, who proposes another approach. The licensee would combine engineering calculations and judgment, PRA techniques, and some seismic analyses to identify the vulnerable elements in safety-related systems and the best ways of upgrading them to improve seismic resistance. The staff has noted the low power level of Big Rock, the low population around the site, and the consequent mild results of calculations of even core melt accidents. The staff has used the regulatory flexibility offered by these circumstances to accept the licensee's approach, subject to review of results and inclusion of various issues from the initial topic review. It is a reasonable and appropriate decision and, having often advocated a flexible approach to these small plants, one I applaud the staff on making.

The design codes, criteria, load combinations, etc. matters will be worked into the licensee's seismic design approach and will be coordinated with similar PRA-based approaches for wind loads, tornado missiles, and pipe breaks to achieve a generally consistent level of upgrading of structures.

4.14 Topic III-8.A: Loose parts monitoring. Not required, because experience and PRA-type analysis show low safety significance. This has been the standard SEP review outcome, with which I agree, on this topic.

4.15 Topic III-10.A: Most motor-operated valves at Big Rock don't need attention to the thermal overload protection devices, the subject of this topic, because said valves do not have to function in accidents. Those that do (six of them) will have the thermal overload protection bypassed except when testing the valves. That is one of the staff's alternatives and is a reasonable solution.

4.16 Topic V-5: Primary system leakage detection. Big Rock has the recommended three systems and seems to meet current standards for primary leakage detection except for seismic qualification requirements. However, here, as in other SEP plants that do not have restraints against pipe whip, the staff is concerned about a leakage detection sensitivity good enough to catch a high pressure pipe leak before it could become a break. The issue thus is tied to the pipe breaks inside containment topic, and final resolution awaits the outcome there. The staff position is the same as for other SEP plants. [Another editorial nit. Check the following phrase from page 4-16, middle of the large lower paragraph, which doesn't make sense to me: "which is not the small break (high-energy pipe break (HEPB)) inside containment but a BWR pipe crack and the effects on HEPB."]

4.17, 4.18, 4.19 Topics V-10.A, V-12.A, and VI-1: These are various water chemistry-related topics. The key one (V-12.A) is primary water impurity limits. The staff concludes, looking at Table 4.2, that the Big Rock impurity limits are not enough different from those of the pertinent Regulatory Guide (1.56) as to require changing. Further, considering the 20 years of operating experience at Big Rock, the staff concludes that the licensee's procedures are adequate and do not need to be put in the unit Technical Specifications. I can hardly restrain my enthusiasm for this well-justified outcome.

The other topics involve questions of tube corrosion in residual heat removal exchangers and post-accident chemistry. The tube corrosion matter is settled by finding the present chloride limits in primary water acceptable and Lake Michigan emergency water impurities manageable under present procedures and Tech Specs. It is a reasonable conclusion, with long operating experience to support it. The post-accident chemistry matter is similarly concluded and the licensee agrees to look at organic coatings inside containment to assure that they will not strip and block sumps, pumps, etc. in a post-accident environment, and to inspect the coatings periodically.

4.20 Topic VI-4: Containment. There are a variety of lines penetrating containment, safety and non-safety, from vent and drain lines to the main steam line, that do not have isolation provisions in strict accordance with current requirements. These are dealt with in groups under this topic. Various resolutions are reached, from sealing off unneeded lines to administrative controls and improved in-service inspections. Some isolation valving is judged adequate as is. The various resolutions on isolation provisions seem reasonable in the circumstances, especially in view of the limited PRA results on containment isolation that show containment leakage due to isolation failure is about one-thousandth as likely as containment leakage from all sources. [A third editorial complaint. The third last sentence on the page is peculiar. I suspect that reference to electrical faults is an error. Also, the penultimate sentence bothers me. Penetrations H-28 and 29 involve systems closed outside containment, according to Appendix D, and the probability of failure of those closed systems can't be as high as 0.1/yr.]

In addition to isolation provisions, this topic covers Appendix J (to 10 CFR 50) containment leakage test requirements. Big Rock had previously been exempted from some Appendix J requirements: others are discussed under this topic. The staff now accepts the plant's airlock testing schedule, improved main steam line isolation testing, and closed-system-inside-containment isolation testing in lieu of full-dress Appendix J provisions, and the licensee has agreed to seal-weld pipe caps on spare penetrations to avoid testing them.

4.21 Topic VI-10.A: The issues are frequency and extent of reactor protection system response time tests. The Big Rock test frequency is lower than the standard Tech Spec value, but the staff reasonably concedes that long operating experience justifies the lower frequency. The matter of the extent of response time testing comes down to whether or not it is worthwhile to include neutron detector cables and signal processing electronics to the tests. Because the staff consultant's PRA shows it to be worth little to safety, the additional testing is declared unnecessary. I agree.

4.22 Topic VII-1.A: Reactor protection system isolation. The licensee has made some adjustments in the isolation (electrical) provisions and in view of these changes, the nature of the RPS power supplies at Big Rock, and plant experience in riding out undervoltage events without equipment damage, the staff has closed this topic.

4.23 Topic VIII-3.B: DC system monitoring and annunciation. Big Rock has a unique dc layout, with just one battery and dc system for general plant dc services. However, the onsite ac systems do not depend for switching power on their dc system. Also, there are separate batteries for each of four depressurization system channels and separate starting batteries for the diesel generators and diesel-driven fire pumps. All of these separate systems result in a low safety significance for any single battery/system. The licensee has increased the testing of the plant general dc system and the staff has accepted that as enough. I have found the staff to be generally conservative in the area of dc systems and expect that they are right in this case. Still, if there is no indication in the control room of any battery charger output current or voltage, dc bus voltage, battery current, high discharge rate, or battery and charger breaker or fuse status, how are the operators sure they will know within one hour [the LCO time for inoperable battery (dc system)] that the dc system is down?

4.24 Topic VIII-4: The issue is electrical protection (fuses or breakers) for circuits leading through containment penetrations. Since a number of PRAs have included this subject and none have found it of any safety significance, the fact that some Big Rock backup circuit breakers have overlong operating times by current standards was declared acceptable. I agree with that conclusion.

4.25 Topic IX-3: Station service and cooling water. Staff review found only the fire water system to be essential for Big Rock, and that to be acceptable if there were procedures to recover flow after a piping failure, and modifications as necessary to avoid having any single pipe failure that could not be routed around. The licensee has provided the procedures and the staff has accepted them. Good enough.

4.26 Topic IX-5: Ventilation systems. Two issues remained after the initial topic reviews. The first concerned hydrogen buildup around the batteries during charging. This was solved by procedures to open doors if normal ventilation fails. The second concerned ventilation of the diesel generator room, shown to be inadequate when an extended diesel run melted tar on the building roof. The solution is a new automatic exhaust fan and new intake louvers. Seems reasonable.

4.27 Topic XV-8: Control rod withdrawal accident. Big Rock has neither a rod worth minimizer nor a rod block monitor. However, analyses show that misoperation of a high worth rod, even with a somewhat delayed scram, does not lead to fuel damage. The plant therefore meets current criteria and this topic is closed.

4.28 Topic XV-18: Main steam line break (MSLB) outside containment. The issue here is keeping the radiological consequences of a MSLB to a small fraction of the Part 100 guidelines, using the classical, highly conservative calculations. If the present Tech Spec limits on primary water impurities are retained, the maximum MSLB doses are about one-third the Part 100 guidelines, conservatively calculated, but above the staff's "small fraction". The staff wants the standard Tech Spec limits imposed, "for dose equivalent iodine-131", whatever that means. Since the overall probability of a MSLB is given in the Big Rock PRA as 1×10^{-8}/yr, which could be wrong by a factor of 100 and still be a neglectable probability, and since the dose calculation is very conservative so that actual MSLB doses would be expected to be a factor of 4 to 10 less than that calculated, I don't find the exercise worthwhile.

In the LaCrosse SEP review, accidents that caused some limited fuel damage also showed calculated doses somewhat higher than the "small fraction" of Part 100. In that case, the integrated assessment team noted the considerable conservatisms in the classical dose calculation and concluded that in any real event the Part 100 guidelines would certainly not be exceeded and that the fraction of Part 100 guidelines were unlikely to be exceeded. So they blessed the situation and signed off. The present case looks very similar to me: why not the same result here?

COMMENTS ON THE NON-SEP TOPIC REVIEWS - SECTION 5

The non-SEP topic review items come in two groups. The first group, covered in Section 5.3, is composed of all the non-SEP items in the licensee's integrated assessment (Appendix H). The second group, covered in Section 5.4, picks up the remaining regulatory actions of significance pending at Big Rock. Comments on the first group follow.

5.3.1: There are several subtopics in this item, all associatd with reactor depressurization system (RDS) valve reliability. The RDS is an important safety system at Big Rock, so it needs to function reliably. It is also a concern to the licensee since the RDS discharges to the containment and is a hazard to operating personnel who are frequently in the containment. The licensee's assessment puts RDS pilot valve leakage at the top of his list of things to fix. The staff agrees, and so do I. The other items are desirable, and should be attended to, but at lower priority in the staff's view. I agree.

5.3.2: Alternate shutdown panel and procedures. The PRAs of both staff and licensee showed this to be a high priority issue -- first on the staff's list of risk-reduction measures and secondly on the licensee's. It appears to be a highly desirable addition.

5.3.3: This item includes several subtopics that are more or less related to control systems and plant control. All are significant issues. The first is to study and then fix the tendency of the turbine bypass valve control system to malfunction. The second is to change the reject valve circuitry so that primary coolant makeup is maintained after a load rejection. These issues have both safety and plant availability and operability aspects. The licensee's PRA and integrated assessment ranked them third and fifth in priority. The staff ranked them lower but agreed with the licensee's proposed actions and schedule.

The other two issues in this group are upgrading of emergency operating procedures and control room design review, both TMI Action Plan issues. They seem to be going ahead without significant problems.

5.3.4: Three issues under the general heading of shielding: the TMI shielding requirements for post-accident conditions; control room habitability in the event of chemical spills, noxious gases, or radiation; and a plant improvement to air condition the control room for operator comfort. On the post-accident shielding, the licensee wanted a delay until the results of his PRA were in hand. Further evaluations of cost-effectiveness of proposed shielding measures are now underway (or recently finished). Decisions on shielding measures will have to be covered in a supplement to this report.

On control room habitability, the licensee's analyses show acceptable conditions at Tech Spec containment leakage, with the grossly conservative accident source term assumptions customarily used. It does not appear practical to make the control room fully resistant to the worst accident conditions, at least as calculated on the customary basis, and the staff has accepted that situation. I think it is good enough "as is", although the licensee has suggested a look at some practical modifications that would help in a few accident sequences.

5.3.6: Containment matters, covered in part in SEP Topic VI-4, Section 4.20, on leakage testing. The other part pertains to containment purging and the usual struggle between "purgers", who see more safety advantage in easy access to containment to maintain the equipment there, and "nonpurgers", who see more safety advantage in not having to depend on the purge line isolation valves if an accident occurs. Staff concludes that because Big Rock was built with continuous purging in mind, it had better continue, to allow free access. But increased surveillance for operability and leak tightness is the price. A fair compromise, I think, and somewhere close to the safety peak on this issue.

5.3.7: Hydrogen concentration monitoring, post-accident: a TMI issue. Since Big Rock has a large containment volume compared to the core hydrogen generation potential from metal-water reaction, hydrogen is not an urgent concern in any post-accident situation. However, over a long time, radiolytic hydrogen could, in principle, be a problem. The staff wants evaluation of the benefits of a hydrogen monitor for the long-term situation. I would think the capability to analyze gas samples for hydrogen, and appropriate sample lines from containment would do the trick.

5.3.8: Scram discharge volume matters: some questions about valve coordination are being studied. Also, the question of supplementing the dump tank level instrumentation has been resolved in favor of no changes, based on the licensee's PRA, which shows no significant benefits. The reasoning is OK. This is another of many instances where the insights from the licensee's PRA are critical to the decision.

5.3.9: Water treatment system improvements. No comment.

5.3.10: Identification and sealing of reactor coolant system vent and drain lines that now have only a single isolation point -- typically a valve. A program is agreed upon.

5.3.11: TMI radiation monitoring items: stack gas monitor and containment high range monitor. Both issues seem to be in hand.

5.3.12: A plant improvement in storage space. No comment.

5.3.13: In-core flux detectors are required by the present Tech Specs but are not necessary because ex-core detectors carry the safety functions and flux wires are used to check the power distribution. Staff is willing to take the in-cores out of the Tech Specs, but wants to put the flux wires in. I agree the in-cores should come out, but question putting the flux wire system in, and how one would write it into the Tech Specs anyway. Are the flux wire traverses really needed for safety? It doesn't sound so from the draft report. How do you write a Tech Spec on a system that is used occasionally to irradiate a wire that is then counted to get a flux distribution?

5.3.14: Two items under the heading of fire protection. The first is the infamous "associated circuits" issue, the regulatory practice on which has long since made me regret voting for Appendix R. In this case, licensee and staff seem to have hammered out an agreement. Fair enough. The licensee wants to schedule completion some 20 months hence. Staff fire protectionists predictably want this done immediately. I vote for the licensee.

The second issue, another Appendix R matter, involves various fire barriers or shields apparently needed to satisfy fire separation criteria in the event of a loss of offsite power. Both the licensee's assessment and the staff's PRA give low importance to these measures. Nevertheless, staff seems determined to go ahead with at least some (including the most cumbersome) of these measures, for reasons I find unconvincing.

5.3.15: The licensee proposes to replace leaking tube bundles in the heating and cooling heat exchangers. No comment.

5.3.16: Ventilation of a control panel, to eliminate instrument problems from high temperatures. No comment.

5.3.17: A program to get the correct air pressure supplied to air-operated valves. No comment.

5.3.18: Recirculation pump trip -- an anti-ATWS measure. Staff and licensee PRAs show low importance for this measure at Big Rock, and it would be expensive to install. The staff has agreed it would not be cost-effective. I think that is the right decision in this case. Since the Commission has just passed an ATWS rule, an exemption will be needed, I think.

5.3.19: The licensee's PRA shows inadequate core cooling instrumentation, a TMI item, to be of small value at Big Rock. The cost would be high. The decision is not to require it. OK.

5.3.20: Control of heavy loads; cranes. No comment.

5.3.21: Quality assurance program improvements. OK.

5.3.22: A licensee program to deal with occasionally sticking relief valves used as a transfer path for re[illegible] to the waste system. Good.

5.3.23: Radwaste monitor backwash system. An abandoned project. No comment.

5.3.24: Definition of operability in the Tech Specs -- a generic letter item. The staff wants the Tech Specs to include definitions of "operability" for various safety systems and LCOs for cases where both trains of a system are out. That is all right. It saves argument in the long run.

5.3.25: This item concerns updating the Final Hazards Summary Report (FHSR) and the system drawings. The licensee has a scheme for referencing existing reports, etc., to accomplish the FHSR updating. It is acceptable for Big Rock, in view of the size and age of the plant, but would not be appropriate generally, in my view. The drawing update should correct some differences between valve lineup sheets, system drawings, and piping and instrumentation diagrams.

5.3.26: High point vents. Big Rock has high point vents, per the TMI Action Plan item, but has not connected them up. The licensee argues it would be expensive to complete the system, and unnecessary because the depressurization system can be used to vent the reactor vessel. The staff finds merit in the argument and agrees, but says if the vents are not to be used they should be either removed or properly supported and tested. Good for the staff; right on both counts.

5.3.27: Appendix I matters: radiological effluent Tech Specs. The licensee has proposed some; staff is considering which elements need touching up and how. Seems to be well in hand.

Section 5.4, Items 5.4.1 to 5.4.12: The twelve items in Section 5.4, the second group of non-SEP topic reviews, are mainly status summaries for these "other" regulatory actions. In most items, there has been substantial progress toward resolution, and some are essentially complete although not formally closed. I did not find anything to complain about in these items. Rather, I was pleased to note again the sensible way in which the particular characteristics of Big Rock were being taken into account in shaping generic requirements to fit this specific unit.

Sincerely,

JM Hendrie

Joseph M. Hendrie

JMH/dt

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October 27, 1983

To: C. I. Grimes, Acting Chief
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From: Herb Isbin Herb Isbin

BIG ROCK POINT PLANT
Review of Draft Report NUREG-0828
Integrated Plant Safety Assessment
Systematic Evaluation Program

The Big Rock Point Plant is the ninth plant to be reviewed in the Systematic Evaluation Program (SEP). Unlike previous reviews, this Draft Report presents not only SEP-identified Topics, but also an evaluation of the licensee's integrated assessments including Unresolved Safety Issues (USI), Three Mile Island (TMI) Action Plan Items, and plant-initiated items. Additionally, an updating is provided for other licensing issues which are pending. Although different cut-off dates are involved (i.e. January 27, 1983, for the SEP Topics; submittal of the licensee's integrated assessment on June 1, 1983; and September 12, 1983, updating on pending licensing actions), the issues have been presented with unusual clarity.

The SEP review starts with 137 Topics, with a subsequent deletion of 29 as being not applicable and a deferral of 23 for USI and TMI Action Plan Items. Of the remaining 85 Topics, 53 were determined to have met current criteria or were acceptable on another defined basis. During the SEP review, another 2 Topics were made acceptable based upon modifications made to the emergency plan and additional analyses made for a license amendment permitting operation with les than all loops in service. No SEP Topic was identified that required prompt action. The remaining 30 Topics were considered for the integrated review. Division of the Topics leads to the enumeration of 51 Issues. (SEP Topic V-4 (Piping and Safe End Integrity) was noted as being reinstituted by the Staff, but I did not find any additional discussions.)

The licensee's plant-specific probabilistic risk analysis (PRA) is under NRC review. Consequently, the SEP Staff was able to undertake a limited PRA based upon the plant-specific PRA. For each issue selected, an estimation was made of the expected averted person-rem per year dose based upon the impact of the proposed resolution. For the SEP-identified Topics, 17 were evaluated. The PRA evaluations were extended to include 12 additional TMI and generic open issues from the licensee's submittal and 11 additional issues from the licensee's PRA and NUREG-0737 action items. Reduction in dose would be expected for 21 issues and the implementation costs were used to evaluate

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how expenditures of resources would best be directed. Some differences between Staff and licensee priorities were identified. In all remaining issues analyzed, only a negligible reduction in dose would be expected.

Recognition of the plant's small size, location, and specific features, together with the application of the licensee's and the Staff's PRAs, has reduced the number of items that require backfitting. The evaluations presented appear to be reasonable and prudent.

A new and important feature of the Draft is the inclusion of the licensee's integrated assessment of "all" issues with the view of establishing a "living schedule" for resolution and implementation. The SEP Staff has begun the process of an integrated review that goes beyond the SEP-identified Topics to include the USI, TMI and other generic issues. Opportunities for plant-initiated improvements are being provided within the flexibility of the scheduling and the justification in commitment of plant resources. Resolution of issues are being enhanced by the reviews and discussions of the Staff with the licensee on strategy, criteria, and methodology for establishing the "living schedule." I have been favorably impressed by the initiatives taken by the licensee and by the judgments being made by the Staff.

Agreement on methods for resolving most issues appears to have been reached between the Staff and the licensee. A few remaining issues involve further reviews by either the Staff or the licensee and pertain primarily to the need for additional Technical Specifications and formalization of some emergency procedures.

Todate, no SEP supplements have been issued for the eight previously reviewed plants. For the Big Rock Point Plant, completion of the Staff's integrated review, including evaluation of the licensee's implementaion schedule with any requirements for preimplementation design review by the Staff, will be presented in a final Integrated Plant Safety Assessment Report. In my August 3, 1983, letter to C. I. Grimes, I stressed the importance of including SEP Topics, USI and TMI Action Plan Items, pending licensing amendments, and other ongoing NRC regulatory activities, in the final integrated assessment. This Draft Report takes a first step in this direction. Encouragement should be given for the participation of the SEP Staff in resolving ALL issues and pending licensing actions. Such support is needed for assuring a "living schedule" for the integrated assessments. The schedule must provide appropriate flexibility for modifications and adjustments, for introduction of plant-initiated improvements, for including or deleting items with the development of new information and operational experiences, and for reasonable allocation of plant resources with due regard to improvements in safety and reliability.

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

January 24, 1984

Docket No. 50-155

Dr. Robert J. Budnitz
Dr. Joseph M. Hendrie
Dr. Herbert S. Isbin

Dear Gentlemen:

SUBJECT: RESPONSE TO SPECIFIC COMMENTS MADE BY NRC STAFF CONSULTANTS ON THE BIG ROCK POINT PLANT INTEGRATED PLANT SAFETY ASSESSMENT REPORT

References: (1) Letter from R. J. Budnitz, FRA, to C. I. Grimes, NRC, dated November 3, 1983.
(2) Letter from J. M. Hendrie, BNL, to C. I. Grimes, NRC, dated November 14, 1983.
(3) Letter from H. S. Isbin to C. I. Grimes, NRC, dated October 27, 1983.

Enclosed for your information is the staff's reply to specific questions and comments raised during your review of Section 4 and 5 of the draft NUREG-0828, Integrated Plant Safety Assessment Report for Consumers Power Company's Big Rock Point Plant.

The staff is revising the affected sections of the report to reflect your comments on the issues and tabulation errors. These corrections and an implementation schedule for the corrective actions defined will be presented in the final version of this report.

Sincerely,

Christopher I. Grimes

Christopher I. Grimes, Acting Chief
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Enclosure:
As stated

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BIG ROCK POINT RESPONSES TO CONSULTANTS

Section 4.2 - Topic II-3.B, Flooding Potential and Protection Requirements

Comment

On page 4-2, the short list near the topic says "...(PMS) from wave runup 586.8 ft msl," while its penultimate paragraph says ...this estimate did not include the effect of wave runup." (J. Hendrie)

Response

Page 12 of the staff SER (Appendix E Topic II-3.B first citation) states "The resulting significant wave runup was to elevation 586.8 ft msl." IPSAR page 4-2 has been corrected.

Section 4.5 - Topic III-5., Wind and Tornado Loadings

Comment

"I think that insisting on 10^{-4} to 10^{-5} windspeeds at the upper 95% confidence level may be too severe a requirement. I would recommend backing off to, say, a median (50%, confidence level." (R. Budnitz)

Response

The upper 95% confidence level was selected because of uncertainties in the methods used to develop the windspeed probability functions. As stated in Section 4.13, the staff will require that the licensee consider all of the probabilistic analyses collectively, so that a relatively uniform level of protection is provided for all of the "external hazards." The staff believes that the range of 10^{-4} to 10^{-5} will dominate these considerations and the staff will judge the acceptability of any proposed plant modification resulting from the implementation of the general criteria based on the results of the evaluation in this range.

Section 4.9 - Topic III-4.A, Tornado Missiles

Comment

"The last paragraph of the write-up says that the licensee proposes to evaluate the damage probability from tornado missiles in conjunction with his PRA. What tornado missile spectrum will be used"? (R. Budnitz)

Response

The licensee has been requested to evaluate the Big Rock Point design against the two missiles described in SRP 3.5.1.4. The missile velocities will be determined as a percentage of tornado velocity (or straight wind) at a specified probability and confidence level. As noted in our response to Dr. Budnitz's comment on Section 4.5, the staff currently requires an evaluation of windspeeds in the range of 10^{-4} to 10^{-5} at the upper 95% confidence level. The staff's safety evaluation for this topic (Appendix E Topic III-4.A first citation) listed 10 systems which the licensee had not evaluated and six systems that had been evaluated acceptably. The PRA is being used to determine: (1) the affect on core damage probability of various wind loadings, tornado loadings and missiles; (2) the maximum windspeed at which minimum systems and structures may be available to safely shutdown the plant; and (3) the cost effectiveness of proposed modifications. The tornado missiles will be evaluated in the same way as the wind loads, as described in the response for Section 4.5.

Section 4.10 - Topic III-5.A, Effects of Pipe Break on Structures, Systems and Components Inside Containment

Comment

"In the last paragraph, the licensee is said to believe that the probability of a high-energy line break is small enough that corrective actions will not be cost effective. I wish to warn NRC that a careful analysis of the uncertainties in the PRA numerical conclusions is called for before this conclusion can be accepted; in particular, there might be some reasonable chance that that 'correct' answer lies considerably higher in value than the best estimate value given, which could obviate the conclusion." (R. Budnitz)

Response

The licensee's methods for probabilistic risk assessment (PRA) have been reviewed in detail by the staff. The licensee has also presented additional probabilistic analyses, using different models, which have come to the same conclusion (Appendix E, Topic III-5.A second citation). These confirmatory analyses were performed because of the numerical uncertainties noted by Dr. Budnitz.

Based on the staff review of the PRA and the additional confirmatory analyses, the staff has concluded that this issue has been resolved acceptably. The results of this review were described in the staff SER (Appendix E, Topic III-5.A first citation) and will be addressed in the final version of the IPSAR.

Section 4.12 - Topic III-6, Seismic Design Considerations

Comment

"The text discusses identifying 'weak links', which are the cut sets (that is, accident sequences) with the highest likelihood of leading to an unfavorable end-state for the reactor. However, there is no discussion on whether any cut-off will be used. For example, perhaps even the 'weakest' of the 'weak links' is actually adequately safe, in the sense that its probability and consequences are acceptable. I am puzzled by the write-up." (R. Budnitz)

Response

The approach proposed by the licensee involves combinations of cut sets and existing deterministic seismic analyses. Rather than demonstate seismic capability of all safety-related equipment, systems and structures by conservative analyses, which is current practice for demonstrating "adequately safe" for seismic events, the licensee will use combinations of cut sets to identify equipment required for safe shutdown for limiting transients and accidents that might be caused by a seismic event and judge the seismic capability of that equipment based on existing analyses, experience and engineering judgment. The equipment would then fall into broad categories of seismic capability. There is no "cut-off", per se; the licensee will be expected to demonstrate safe shutdown for a minimum of 0.12g with some implicit or explicit capability beyond that for margin to ensure that seismic events beyond the safe shutdown earthquake (SSE) do not dominate risk. In practice, the staff expects that all of the equipment that falls into categories below 0.12g would be upgraded by (1) more detailed analysis to demonstrate a higher capability, or (2) physical modifications. The staff will review the licensee's implementation of this approach to assure that the critical equipment is properly identified and categorized. Cost-benefit considerations will principally control the degree to which higher capabilities must be demonstrated.

Section 4.16 - Topic V-5, RCPB Leakage Detection

Comment

"The long paragraph at the bottom of page 4-16 of the text is muddled and hard to follow. I couldn't follow it as well as I would like and suggest that it be re-written so that the rationale for the staff position emerges clearly." (R. Budnitz)

"Big Rock Point has the recommended three systems and seems to meet current standards for primary leakage detection except for seismic qualification requirements. However, here, as in other SEP plants that do not have restraints against pipe whip, the staff is concerned about a leakage detection sensitivity good enough to catch a high pressure pipe leak before it could become a break. The issue thus is tied to the pipe breaks inside containment topic, and final resolution awaits the outcome there. The staff position is the same as for other SEP plants. [Another editorial nit. Check the following phrase from page 4-16, middle of the large lower paragraph, which doesn't make sense to me: "which is not the small break (high-energy pipe break (HEPB)) inside containment but a BWR pipe crack and the effects on HEPB."]" (J. Hendrie)

Response

The referenced paragraph has been revised. The staff was only trying to point out the limitations of probabilistic analyses in this application. The probabilistic analyses do not adequately assess all of the risk reduction potential of leakage detection systems.

Section 4.20 - Topic VI-4, Containment Isolation System

Comment

"The third last sentence on the page is peculiar. I suspect that reference to electrical faults is an error. Also, the penultimate sentence bothers me. Penetration H-28 and 29 involve systems closed outside containment, according to Appendix D, and the probability of failure of those closed systems can't be as high as 0.1/yr." (J. Hendrie)

Response

Appendix D pages 27 and 71 are the basis for the numbers appearing on page 4-20. (The 1.4×10^{-4} number has been corrected to 1×10^{-4}/yr.) Electrical penetrations were included in the general discussion of containment isolation to provide contrast with the valving issues. The 0.1 probability is a failure to isolate upon demand derived from the licensee's PRA. Page 4-20 has been corrected accordingly.

Section 4.20 - Topic VI-4, Containment Isolation System - Closed Systems

Comment

Under 4.20.6, the licensee apparently does not agree that a periodic inspection procedure is worthwhile. Is there still room for negotiation on this one, or has the staff position prevailed? My own view is that it depends on how much effort is really involved." (R. Budnitz)

Response

Yes, there is room for negotiation because the extent of inspection to accomplish the objective has not been defined. This specific issue was addressed at both the ACRS subcommittee and full committee meetings.

Section 4.23 - Topic VIII-3.B, DC Power System Bus Voltage Monitoring and Annunciation

Comment

"If there is no indication in the control room of any battery charger output current or voltage, dc bus voltage, battery current, high discharge rate, or battery and charger breaker or fuse status, how are the operators sure they will know within one hour [the LCO time for inoperable battery (dc system)] that the dc system is down?" (J. Hendrie)

Response

Control room monitoring of the 125 V DC system currently consists of a "125 V D-C System Trouble" alarm which actuates on battery/battery charger over-current, positive or negative bus ground, loss of charger input supply voltage, or 125 V DC bus undervoltage; local indication consists of charger output current and bus voltage, current, and ground. Upon receipt of an alarm, an equipment operator is dispatched to the local panel in the electrical equipment room.

Section 4.28 - Topic XV-18, Radiological Consequences of a Main Steam Line Failure Outside Containment

Comment

"The issue here is keeping the radiological consequences of a MSLB to a small fraction of the Part 100 guidelines, using the classical, highly conservative calculations. If the present Tech Spec limits on primary water impurities are retained, maximum MSLB doses are about one-third the Part 100 guidelines, conservatively calculated, but above the staff's 'small fraction.' The staff wants the standard Tech Spec limits imposed, 'for dose equivalent iodine-131,' whatever that means. Since the overall probability of a MSLB is given in the Big Rock Point PRA as 1×10^{-8}/yr, which could be wrong by a factor of 100 and still be a neglectable probability, and since the dose calculation is very conservative so that actual MSLB doses would be expected to be a factor of 4 to 10 less than that calculated, I don't find the exercise worthwhile.

In the LaCrosse SEP review, accidents that caused some limited fuel damage also showed calculated doses somewhat higher than the 'small fraction' of Part 100. In that case, the integrated assessment team noted the considerable conservatisms in the classical dose calculation and concluded that in any real event the Part 100 guidelines would certainly not be exceeded and that the fraction of Part 100 guidelines were unlikely to be exceeded. So they blessed the situation and signed off. The present case looks very similar to me: why not the same results here?" (J. Hendrie)

Response

The issue in the LaCrosse review was the consequences of fuel handling accidents, which are dominated by the accident analysis assumptions. In this case, like the other SEP reviews of boiling water reactors (Oyster Creek, Dresden 2 and Millstone 1), the radiological consequences of steam line breaks is primarily controlled by the primary coolant activity. Restricting that activity without unduly restricting plant operation not only reduces the potential radiological consequences of such accidents but also provides a tighter monitor on fuel failures and crud buildup in the primary system.

Section 5.3.1.1, RDS Pilot Valve Leakage

Comment

"Item 5.3.1.1 seems to be very important in a safety sense. I am quite surprised that the licensee's calculation shows such a high likelihood of a failure leading to a blowdown (6.7×10^{-3} per year). The risk to personnel from such a blowdown is obviously high. The concluding paragraph states that if the leakage can be reduced significantly, 'compared to the cost,' suitable fixes will be done. What if the cost is too high? What is the staff's position in that eventuality?" (R. Budnitz)

Response

As in any cost-benefit anlaysis, if the cost is too high in comparison to the benefits (reduced likelihood of an inadvertant blowdown), and no less-costly, alternative measures can be identified, we would find the present design acceptable and rely on surveillance and maintenance practices to minimize the potential for such failures.

Section 5.3.1.3, Full-Strike Testing of RDS Valves

Comment

"It is stated that continued operation is justified by the 'low likelihood of mechanical failures.' How is this known?" (R. Budnitz)

Response

That conclusion is based on operational and testing experience. The staff is not aware of solenoid-operated valve failures where a valve has failed to fully open when its coil was operating properly. Part of the licensee effort will be to determine if any partial operation has occurred, why it happened, and how the cause may be detected as part of their determination of whether partial-stroke tests are valid.

Section 5.3.7 - Hydrogen Monitoring

Comment

"Since Big Rock has a large containment volume compared to the core hydrogen generation potential from metal-water reaction, hydrogen is not an urgent concern in any post-accident situation. However, over a long time, radiolytic hydrogen could, in principle, be a problem. The staff wants evaluation of the benefits of a hydrogen monitor for the long-term situation. I would think the capability to analyze gas samples for hydrogen, and appropriate sample lines from containment would do the trick." (J. Hendrie)

Response

The staff agrees and sample lines are available. However, in order to accomplish such a function, the procedures need to be thought through beforehand to determine the optimum sampling and minimize personnel exposures. It is also concievable that alternate gas analysis equipment might be needed.

Section 5.3.13 - Incore Detectors

Comment

"In-core flux detectors are required by the present Tech Specs but are not necessary because ex-core detectors carry the safety functions and flux wires are used to check the power distribution. Staff is willing to take the incores out of the Tech Specs, but wants to put the flux wires in. I agree the in-cores should come out, but question putting the flux wire system in, and how one would write it into the Tech Specs anyway. Are the flux wire traverses really needed for safety? It doesn't sound so from the draft report. How do you write a Tech Spec on a system that is used occasionally to irradiate a wire that is then counted to get a flux distribution?" (J. Hendrie)

Response

The flux wire traverses are needed to verify, on a periodic basis, that the expected flux distribution exists. However, the expected changes in flux do not occur at such a rate as to require continuous monitoring from an incore detector system. The staff will work with the licensee to develop a suitable technical specification for periodic surveillance and calibration of the ex-core detectors.

Section 5.3.14 - Fire Protection

Comment

"Two items under the heading of fire protection. The first is the infamous 'associated circuits' issue, the regulatory practice on which has long since made me regret voting for Appendix R. In this case, licensee and staff seem to have hammered out an agreement. Fair enough. The licensee wants to schedule completion some 20 months hence. Staff fire protectionists predictably want this done immediately. I vote for the licensee.

The second issue, another Appendix R matter, involves various fire barriers or shields apparently needed to satisfy fire separation criteria in the event of a loss of offsite power. Both the licensee's assessment and the staff's PRA give low importance to these measures. Nevertheless, staff seems determined to go ahead with a least some (including the most cumbersome) of these measures, for reasons I find unconvincing." (J. Hendrie)

Response

The fire barriers needed to satisfy the separation criteria in Appendix R provide the fundamental design protection of redundancy and also provide defense-in-depth protection against other common-mode failures like pipe-break effects and missiles. The staff believes that economical barriers or alternative designs can be developed. Moreover, the probabilistic analyses in this area have large uncertainties and uncomfortable assumptions.

Section 5.3.18 - Recirculation Pump Trip

Comment

"Staff and licensee PRAs show low importance for this measure at Big Rock, and it would be expensive to install. The staff has agreed it would not be cost-effective. I think that is the right decision in this case. Since the Commission has just passed an ATWS rule, an exemption will be needed, I think." (J. Hendrie)

Response

The ACRS noted, and the staff agrees, that the pump trip design does not have to meet Class 1E criteria for ATWS considerations and a less costly design could provide an improved capability to migitate ATWS events. Consequently, the staff has revised its position to require that the licensee evaluate the cost-benefit of alternate designs for pump trip. The licensee has agreed to this evaluation. Whether an exemption will be required will depend on the results of that evaluation.

Comment

"Topic V-4 was noted as being reinstituted by the staff, but I did not find any additional discussions." (H. Isbin)

Response

The Big Rock Point design was found acceptable during the topic evaluation.

Sections 4 and 5 address only those topics for which the staff has issued a safety evaluation report in which an unresolved difference from current licensing criteria is identified or for which a safety evaluation has not been issued.

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The Systematic Evaluation Program was initiated in February 1977 by the U. S. Nuclear Regulatory Commission to review the designs of older operating nuclear reactor plants to confirm and document their safety. The review prcvides (1) an assessment of how these plants compare with current licensing safety requirements relating to selected issues, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

This report documents the review of the Big Rock Point Plant, operated by Consumers Power Company located in Charlevoix, Michigan. Big Rock Point is one of ten plants reviewed under Phase II of this program. This report indicates how 137 topics selected for review under Phase I of the program were addressed. It also addresses a majority of the pending licensing actions for Big Rock Point, which include TMI Action Plan requirements and implementation criteria for resolved generic issues. Equipment and procedural changes have been identified as a result of the review.

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