U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.	50-528/92-35, 50-529/92-35, and 50-530/92-35
Docket Nos.	50-528, 50-529, and 50-530
License Nos.	NPF-41, NPF-51, and NPF-74
Licensee	Arizona Public Service Company P. O. Box 53999, Station 9012 Phoenix, AZ 85072-3999
Facility Name	Palo Verde Nuclear Generating Station Units 1, 2, and 3
Inspection Conducted	October 1 through November 2, 1992
Inspectors	J. Sloan, Senior Resident Inspector F. Ringwald, Resident Inspector D. Solorio, Resident Inspector (San Onofre) A. MacDougall, Reactor Inspection, Region I
Approved By	Howard J. Wong 12/1/92 H. Wong, Chief, Reactor Projects Section 2 — Date Signed

Inspection Summary:

Inspection on October 1 through November 2, 1992 (Report Numbers 50-528/92-35, 50-529/92-35, and 50-530/92-35)

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors, and a Region I inspector. Areas inspected included:

- review of plant activities
- surveillance testing - Units 1, 2, and 3
- plant maintenance - Units 1, 2, and 3
- management meeting, ISE Review
- manual engineered safety feature actuation not reported - Unit 2
- diesel engine 5 year inspection - Unit 3
- quality assurance program - Units 1, 2, and 3
- licensee response to Rosemount 10 CFR Part 21 - Units 1, 2, and 3
- followup on previously identified items - Units 1, 2, and 3

During this inspection the following inspection procedures were utilized: 30702, 35701, 40500, 61726, 62703, 71707, 92700, 92701, and 93702.

Results: Of the nine areas inspected, no violations were identified.

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General Conclusions and Specific Findings:

Significant Safety Matters: None

Violations: None

Deviations: None

Open Items: 1 new item was opened, 6 items were closed, and 2 items were left open.

Strengths Noted: The response to the potential non-conservative calibration of transmitters affecting the core operating limit supervisory system represented conservative safety consciousness.

Weaknesses Noted: None

DETAILS

1. Persons Contacted

The below listed technical and supervisory personnel were among those contacted:

Arizona Public Service Company (APS)

*R. Adney,	Plant Manager, Unit 3
T. Bradish,	Manager, Nuclear Regulatory Affairs
*R. Bouquot,	Supervisor, Quality Audits
*J. Dennis,	Manager, Operations Standards
*C. Emmett,	Senior Information Coordinator, Management Services
*R. Flood,	Plant Manager, Unit 2
*R. Fullmer,	Manager, Quality Audits & Monitoring
S. Guthrie,	Director, Quality Assurance
W. Ide,	Plant Manager, Unit 1
*R. Kerwin,	Manager, Maintenance Support
*D. Leech,	Supervisor, Quality Audits & Monitoring
*J. Levine,	Vice President, Nuclear Production
*D. Mauldin,	Director, Site Maintenance & Modifications
*J. Napier,	Engineer, Nuclear Regulatory Affairs, Operations
*G. Overbeck,	Director, Site Technical Support
*R. Roehler,	Supervisor, Nuclear Regulatory Affairs, Operations
*A. Rogers,	Technical Assistant, Regulatory & Industry Affairs
*R. Schaller,	Assistant Plant Manager, Unit 1
T. Shriver,	Assistant Plant Manager, Unit 2
*R. Smalley,	Supervisor, Central Maintenance HVAC
R. Stevens,	Director, Regulatory & Industry Affairs

Others

*J. Draper,	Site Representative, Southern California Edison
*F. Gowers,	Site Representative, El Paso Electric
*G. Hammond,	Supervisor, Onsite Licensing, Southern California Edison
*R. Henry,	Site Representative, Salt River Project
*J. Jamerson,	Senior Licensing Engineer, Southern California Edison

*Denotes personnel in attendance at the Exit meeting held with the NRC resident inspectors on November 2, 1992.

The inspectors also talked with other licensee and contractor personnel during the course of the inspection.

2. Review of Plant Activities - Units 1, 2, and 3 (71707)

a. Unit 1

The unit began the inspection period starting up from Mode 3, achieving 100% power on October 4, 1992. Power was reduced to 99.5% on October 8, 1992, as a result of concern over a 10 CFR Part 21 report affecting feedwater and steam flow Rosemount transmitters

(Paragraph 9). The unit returned to 100% power on October 10, 1992. A core operating limit supervisory system (COLSS) failure occurred on October 25, 1992, which resulted in a power reduction to 73% as required by Technical Specifications. The unit returned to 100% power on October 26, 1992. On October 27, 1992, the unit detected a small primary to secondary leak in steam generator number 1 with an estimated leak rate of 0.1 gallons per day. The leak increased to approximately 1.3 gallons per day at the end of the reporting period. The unit ended the inspection period at 100% power.

b. Unit 2

The unit operated at essentially 100% power throughout the inspection period. Several problems with the COLSS required power reductions to comply with Technical Specifications. Power was reduced to 99.5% on October 8, 1992, as a result of concern over a 10 CFR Part 21 report affecting feedwater and steam flow Rosemount transmitters (Paragraph 9). The unit returned to 100% power on October 10, 1992.

c. Unit 3

Unit 3 began this inspection period in Mode 6, with core offload in progress. The offload was completed on October 3, 1992. While defueled, the licensee performed significant planned outage maintenance. Outage activities progressed slightly ahead of schedule during this period. Core reload commenced on October 28 and was completed on October 30, 1992. The unit remained in Mode 6 at the end of the inspection period.

Two inadvertent Balance of Plant Engineered Safety Features Actuation System (BOP ESFAS) actuations occurred while defueled. On October 9, 1992, an operator intending to open one breaker unintentionally opened another, causing the first actuation. On October 14, another actuation unexpectedly occurred, apparently due to a procedural weakness and an operator not taking action implied by a caution in the procedure. The licensee is investigating both these events.

d. Plant Tour

The following plant areas at Units 1, 2, and 3 were toured by the inspector during the inspection:

- Auxiliary Building
- Control Complex Building
- Diesel Generator Building
- Fuel Building
- Main Steam Support Structure
- Radwaste Building
- Technical Support Center
- Turbine Building

- o Yard Area and Perimeter
- o Containment Building

The following areas were observed during the tours:

(1) Operating Logs and Records - Records were reviewed against technical specifications and administrative control procedure requirements.

The inspector noted that the licensee discovered clerical errors in the updates to three emergency operating procedures (EOPs) in Unit 2 on October 13, 1992 which resulted in a large number of blank pages which should have contained procedural guidance. The inspector further noted that operations and operations standards took prompt and aggressive corrective action to identify and correct all EOP errors. The inspector concluded that this represented both inattention to detail with these very important procedures, and prompt and effective corrective action.

(2) Monitoring Instrumentation - Process instruments were observed for correlation between channels and for conformance with technical specifications requirements.

The inspector noted that the licensee continued to experience problems with the reliability of the plant computer and core monitoring computer in Units 1 and 2, which resulted in the loss of the core operating limit supervisory system on several occasions. The inspector concluded that the licensee's response to these failures appeared appropriate.

(3) Shift Staffing - Control room and shift staffing were observed for conformance with 10 CFR Part 50.54.(k), technical specifications, and administrative procedures.

(4) Equipment Lineups - Various valves and electrical breakers were verified to be in the position or condition required by technical specifications and administrative procedures for the applicable plant mode.

(5) Equipment Tagging - Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment was in the condition specified.

(6) General Plant Equipment Conditions - Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that could prevent the systems from fulfilling their functional requirements.

The inspector observed that part of the gasket was missing from a condulet box on the motor operator for Unit 3 valve 3SGE-HV-44, steam generator #2 blowdown isolation valve. This

condition had been identified by the inspector during the last refueling. The inspector verified that there is no safety significance associated with the observed condition. However, the licensee had not initiated a work request to correct the deficiency when first identified. Following the identification of this deficiency during this refueling outage, the licensee initiated an appropriate work request. The inspector concluded that the licensee's current actions were appropriate.

(7) Fire Protection - Fire fighting equipment and controls were observed for conformance with technical specifications and administrative procedures.

(8) Plant Chemistry - Chemical analysis results were reviewed for conformance with technical specifications and administrative control procedures.

(9) Security - Activities observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures included vehicle and personnel access, and protected and vital area integrity.

(10) Plant Housekeeping - Plant conditions and material/equipment storage were observed to determine the general state of cleanliness and housekeeping.

The inspector observed two examples of housekeeping which had the potential for operational impact. The first involved rags and debris on the Unit 1 auxiliary building roof which blocked water from draining. The second involved an unrestrained scaffold cart in the Unit 2 control room near the engineered safety features cabinets. Both issues were promptly addressed by the licensee.

(11) Radiation Protection Controls - Areas observed included control point operation, records of licensee's surveys within the radiological controlled areas, posting of radiation and high radiation areas, compliance with radiation exposure permits, personnel monitoring devices being properly worn, and personnel frisking practices.

During an inspection of the Unit 3 containment, the inspector was given incorrect information regarding the area of high radiation in the 120' pressurizer cubicle. The area posted as a high radiation area in the cubicle did not match the area described by the lead radiation protection (RP) technician. The licensee determined that the reason for the misinformation was that the RP technician was unaware of the posting change due to an omission in the shift turnover. The inspector determined that the actual posting was accurate and concluded that the licensee was adequately addressing the turnover deficiency.

(12) Shift Turnover - Shift turnovers and special evolution briefings were observed for effectiveness and thoroughness.

No violations of NRC requirements or deviations were identified.

3. Surveillance Testing - Units 1, 2, and 3 (61726)

Selected surveillance tests required to be performed by the technical specifications (TS) were reviewed on a sampling basis to verify that: 1) surveillance tests were correctly included on the facility schedule; 2) technically adequate procedures existed for performance of the surveillance tests; 3) surveillance tests had been performed at the frequency specified in the TS; and 4) test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 1

Procedure	Description
32ST-9PK01	"7-Day Surveillance Test of Station Batteries"
36ST-9SB04	"PPS Functional Test - RPS/ESFAS Logic"
36ST-1SE03	"Excore Safety Linear Channel Quarterly Calibration"
72ST-9SB01	"CPC/COLSS Flow Verification"

Unit 2

Procedure	Description
36ST-9SB02	"PPS Bistable Trip Units Functional Test"

Unit 3

Procedure	Description
31ST-9DG02	"Diesel Engine 5 Year Inspection (DGB)"

No violations of NRC requirements or deviations were identified.

4. Plant Maintenance - Units 1, 2, and 3 (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with the maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance/quality control department

involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting.

The inspector witnessed portions of the following maintenance activities:

Unit 1

- o Calibration of the generator stator water outlet temperature instrument
- o Calibration of the "B" shutdown cooling heat exchanger outlet temperature instrument

Unit 2

- o Application of monokote fire protection coating in the "B" essential (PK) battery room
- o Calibration of the volume control tank temperature instrument
- o Replacement of the charging motor on the "A" essential spray pond pump breaker
- o Maintenance of safety-related Magneblast circuit breakers

Unit 3

- o Clean and inspect the spray pond end bell of the EW "A" heat exchanger
- o Plug 8 tubes in EW "A" heat exchanger
- o Remove the feed screw & journal bearing from reactor coolant pump "1B"
- o Repair lifting device for "A" spray pond breaker
- o Inspect and align load center L23 4160V feeder breaker
- o Bearing inspection on essential chiller "B"
- o "B" and "D" essential battery installations (DCP 3XE-PK-037)
- o Retrieval of allen wrench from upper core support plate
- o Installation of diverse auxiliary feedwater actuation system (DCP 3FJ-SB-064)
- o Rework of "B" diesel cylinders 9-R and 10-L
- o Disassemble, inspect and reassemble check valve DGB-V497
- o Post maintenance test run of "B" emergency diesel generator

Lifted Leads - Unit 1

On October 7, 1992, the inspector observed calibration of turbine temperature monitoring instrumentation in Unit 1 which required the lifting of leads and noted that the leads had not been restrained nor insulated. The inspector further noted that one of the leads was in contact with a test probe, and was therefore electrically part of the test circuit. When the inspector questioned this condition, the technician promptly taped the lifted lead to insulate it. A discussion with the I&C foreman confirmed that this was contrary to the newly established lifted lead policy and the I&C technician involved was counselled. Later in the inspection period the inspector observed several other I&C calibration and surveillance test activities which

required the lifting of leads and noted that all other instances appeared to conform to the newly established lifted lead policy.

Circuit Breaker Failure - Unit 2

On Octob_r 9, 1992, the Unit 2 essential spray pond (ESP) pump "A" breaker failed to close on demand as a result of a breaker failure. An immediate investigation revealed that the breaker charging spring motor had fallen off the breaker and was lying on the floor of the cubicle. The inspector observed troubleshooting which identified that the bolts which secured the charging spring motor to the breaker frame were found to be completely loose. All expected loose hardware was located. The inspector observed the licensee install a replacement charging spring motor and retest the breaker satisfactorily. The licensee established a corrective action plan which included inspection of critical breakers for similar loose bolts and initiated a root cause of failure investigation for this breaker. The inspector concluded that the licensee activities appeared appropriate. At the exit meeting, the inspector encouraged the licensee to evaluate these breakers for other failure mechanisms which are not readily evident in light of this and other recently observed failures which were also not readily evident.

Circuit Breaker Maintenance - Unit 2

On October 19, 1992, the inspector observed a portio.. 32MT-9ZZ34, "Maintenance of Medium Voltage Circuit Breakers Type AM-4.16-250," in the Unit 2 electrical maintenance shop. During the performance of section 4.17, Trip Latch Wipe, the inspector noted that the electricians measured the trip latch wipe by applying grease to the trip latch roller and measuring the width of the grease wiped off by the trip latch, rather than by applying grease to the trip latch and measuring the width of the grease wiped on the trip latch roller as specified by the procedure. When the Quality Control (QC) inspector questioned this difference, the electricians explained that this is how they had been trained by a General Electric technical rep esentative and how the procedure was written in the past. At the request of the QC inspector, the electricians repeated the measurement using the methodology specified by the procedure, and obtained the same measurement as before. The QC inspector inserted a hold point in the procedure for an instruction change request (ICR) number to clarify how this measurement should be performed. The inspector concluded that since the measurement using both methodologies produced identical results, there was little technical significance to the difference. The inspector further concluded that this did not follow management expectations for procedure use as expressed in "Principles of Maintenance Management" in that the electricians did not stop and question this difference prior to proceeding. The inspector also concluded that it was appropriate for the QC inspector to question this and initiate a hold point in the procedure for an ICR to clarify the procedure steps.

Essential Cooling Water (EW) Heat Exchanger Maintenance - Unit 3

The inspector observed the plugging of tubes in the Unit 3 EW "A" heat exchanger per work order 575255. The faulty tubes were identified during the planned inspection of the heat exchanger. The mechanic doing the plugging appeared to carefully perform self-verification and no discrepancies were apparent to the inspector. However, the procedure did not require second party or independent verification that the correct tubes were plugged. This observation was discussed with the maintenance supervisor who stated that the intent was to have a second mechanic (lead or foreman) verify the proper placement of the plugs. As a result, the Quality Control department verified the proper installation of plugs in one end of the heat exchanger, but the other end had already been closed out and could not be verified. The inspector concluded that not having a procedural requirement to ensure that second party verification was conducted was a weakness in the work control process.

Work order 549842, for installation of the heat exchanger end bell gasket, did not specify how the gasket was to be installed. After questioning the maintenance personnel, it was determined that gaskets are generally installed with RTV or similar compound that is compatible with the materials involved. In this instance, there was not a compatible compound and the gasket was held in place with metallic tape until the end bell cover plate was installed. The inspector noted that a potential for errors existed by requiring the technician in the field to determine the proper installation method if the work planner already had the needed information. The inspector also noted that the work order also had a pen-and-ink change which was not initialed and dated as specified in licensee procedures, though an Engineering Evaluation Request (EER) supporting the change was included in the work package. The inspector concluded that improvements could be made to this work order, but that the maintenance was adequately performed.

Motor Operated Valve Maintenance - Unit 3

The inspector observed portions of the periodic inspection of safety injection valve 3SIA-UV-635 actuator using maintenance procedure 32MT-9ZZ48, "Maintenance of Limitorque Valve Motor Operators." The technicians identified a cracked end bell dog on the motor end bell and properly submitted a MNCR to evaluate the corrective action. The inspector concluded that the technicians took the appropriate action and properly documented the deficiency. The inspector observed section 4.5.7 for limit switch grease inspection. The technicians were knowledgeable on what type of grease to expect and how to properly evaluate its condition. Appendix D to the procedure had detailed acceptance criteria for the grease inspection. Both technicians observed the grease and determined that it was satisfactory. The inspector concluded that the procedure was effectively written, the technicians were properly trained, and that the actuator was properly inspected and maintained.

Allen Wrench in Reactor Vessel - Unit 3

The inspector observed the retrieval of an allen wrench from inside the Unit 3 reactor vessel. The licensee found the wrench during an inspection of the lower core support plate while the react was defueled. The licensee promptly planned and executed the trieval, which was accomplished smoothly using a magnet suspended from a lanyard. The licensee determined from radioactivity measurements that the wrench had been in the core for at least the last operating cycle. The inspector noted that the licensee has had deficiencies in foreign material exclusion (FME) area control in previous outages, and observed that FME controls in place for this outage appeared adequate. The licensee could not explain how the wrench got into actor vessel. The licensee evaluated the potential damage to fuel assemblies which were in the vicinity of the wrench during the last cycle and determined that there was little potential for damage. The inspector noted that no fuel leakage was observed during the cycle, and concluded that the licensee's response to this issue appeared appropriate.

Essential Chiller Inspection - Unit 3

The inspector observed portions of the restoration from the bearing inspection performed on the "A" Essential Chiller per work order 564651. The inspector noted that some M&TE information was not recorded in appropriate blanks in the work order. Several completed steps did not have data recorded for the calibration due date and the range of the M&TE used, although blanks were provided. Some steps also did not identify the M&TE used. At least one M&TE Usage Form was not found at the time, although it was required to be kept with the work order. It appeared that the work was satisfactorily completed. The licensee managed to fill in some of the blanks in the work order from M&TE Usage Forms that had been completed, but some information could not be readily obtained. The inspector concluded that the workers had not fulfilled their responsibility in completing required documentation of work activities as intended, but that the requirements of procedure 30AC-OME01, "Measuring and Test Equipment (M&TE) Users Administrative Requirements," had been met. The licensee later located the missing M&TE usage forms elsewhere in the work order binder. Additionally, the workers were briefed on M&TE record requirements. The licensee initiated Condition Report/Disposition Request (CRDR) 3-2-0460.

No violations of NRC requirements or deviations were identified.

5. Management Meeting - (30702 and 40500)

On November 2, 1 2, S. Guthrie and two members of the licensee's Independent Safety Engineering (ISE) staff, and K. Hamlin, Manager, Nuclear Safety, m with regional management in the Region V Office. Topics presented by the licensee's staff included:

- o Changes and enhancements from past ISE practices,
- o ISE accomplishments

o ISE challenges

The discussions included several key points:

o The licensee stated that improvements had occurred in their ISE program, including newly hired personnel on the ISE staff, which should make the organization more effective.

o Past practices of the ISE staff spending too much time at their desk and not out in the plant, was a recognized problem. Actions to encourage ISE activity in the plant included establishing satellite offices in each unit, assigning two ISE engineers to be accountable for monitoring daily activities at each unit, and management emphasis on keeping current on plant issues.

o The APS managers stated that the Quality Assurance and ISE functions still needed improvement to reach their expectations, but that they had seen significant improvements over the last few years. Several examples of improvements in the interface between other managers and the ISE staff were discussed.

o Recent events at another Region V utility identified that vendor Owner's Group information was not being effectively implemented by that licensee. The APS staff acknowledged that it was a challenge to review and act upon the very large amount of generic information received from the industry.

Other discussion topics included ISE staffing and training levels, tracking of ISE action items, the Employee Concerns Program, and interfacing between the licensee's senior management, ISE, and Nuclear Safety. The presentation package provided by the licensee is included in this report as Enclosure 2.

6. Manual Engineered Safety Feature (ESF) Actuation Not Reported - Unit 2 (92700)

In September 1992, the inspector received an inquiry by the licensee's Quality Audits and Monitoring (QA&M) department regarding the reportability of a December 23, 1991, event in which a high pressure safety injection (HPSI) pump was started to recover reactor coolant system (RCS) level due to a major leak from a stuck open relief valve in the shutdown cooling system. The licensee had used the HPSI pump after the leak was confirmed to exceed the capacity of all three charging pumps. At the time of the event, Unit 2 was in Mode 5 at 380 psia.

At the time, the licensee initiated Condition Report/Disposition Request (CRDR) 2-1-0274, and determined that the event was not reportable to the NRC. Subsequently, the QA&M department performed a reportability audit and initiated another CRDR upon its determination that the event was reportable due to its conclusion that the use of HPSI constituted a manual ESF actuation.

During a meeting on September 3, 1992, the inspector became aware of the details of the event and noted that the licensee should have evaluated the event for emergency classification in accordance with the licensee's Emergency Plan. The licensee then initiated another CRDR to evaluate the emergency classification issue. The emergency classification issue was referred to Region V emergency preparedness personnel (see Inspection Report 50-528/92-34).

The inspector noted that HPSI was not required to operable in Mode 5, and that Engineered Safety Features (ESF) logic was bypassed per procedures to enable Mode 5 operation. Additionally, the licensee stated that operating procedures allow the use of HPSI for normal RCS makeup.

Discussions were conducted with the NRC Office of Analysis and Evaluation of Operational Data (AEOD) to determine if manually starting the HPSI pump to mitigate the leak constituted a manual ESF actuation, which would be reportable in accordance with 10 CFR 50.72 and 50.73. A September 7, 1990 NRC internal staff letter indicated that an ESF actuation occurs whenever an ESF component is caused to operate, for any reason except responses to testing. However, this position is not clearly supported in generic documents, including NUREG 1022, "Licensee Event Report System," or its supplements. Additionally, in a 1987 internal licensee memorandum, the licensee documented a March 20, 1987 telephone discussion in which an AEOD contact had stated that actuation of ESF components by something other than an ESF signal would not be reportable under the ESF requirements of 10 CFR 50.73. The AEOD contact was indicated to have stated the purpose of the requirement was to capture ESF system actuations, whether due to valid or invalid ESF signals. The inspector concluded that the licensee was not required to report this event to the NRC under ESF reporting criteria.

The inspector evaluated the safety significance of the event, noting that it occurred at the end of a refueling outage with a relatively cold core. The inspector estimated the leak rate to be about 180 gallons per minute. All HPSI pumps and charging pumps, and both trains of shutdown cooling, were operable at the time. The licensee isolated the leak in approximately 30 minutes, and maintained pressurizer level above approximately 28%. The inspector concluded that the plant was not close to losing shutdown cooling, and that if shutdown cooling were lost, a significant margin of time to recover cooling flow existed before boiling or core uncovery would occur. The inspector concluded that the significance of this specific event was low, but noted that the event would have been considerably more serious if the reactor had been recently shut down and if only the minimum equipment required by Technical Specifications were available.

No violations of NRC requirements or deviations were identified.

7. <u>Diesel Engine 5 Year Inspection - Unit 3 (61726)</u>

The inspector observed portions of the Diesel Engine 5 year inspection (procedure 31ST-9DG02) on the Unit 3 "A" emergency diesel generator. The

inspector reviewed the procedure, interviewed personnel, and observed the post-maintenance engine analysis.

The licensee recently revised the surveillance procedure to incorporate a change in the vendor (Cooper-Bessemer) technical manual, C628-0001, section 15, maintenance guidelines. The new guidelines shifted the periodic maintenance emphasis from prescriptive tear down inspections to a predictive approach. The impact of this change was evaluated in Engineering Evaluation Request (EER) 92-DG-028. The evaluation included a discussion of the conceptual differences between the old and new maintenance guidance, identified new maintenance tasks and maintenance tasks that were no longer required, and summarized specific areas where procedural changes were required. As a result, the surveillance procedure was changed to perform a limited visual inspection and an engineering evaluation of various components (turbocharger, cylinder heads, engine lube oil pump, etc.) to determine if more detailed inspections were necessary.

During this surveillance, visual inspections and engineering reviews of performance data, documented in EER 92-DG-033, showed that equipment tear-downs were not required. However, injector fuel pump removal and disassembly was performed on all 20 injectors as part of a separate work order to identify faulty injectors reported by the vendor under 10 CFR Part 21. The inspection found 11 injectors with lot numbers that were either defective or suspect. These injectors were subsequently replaced. No other problems were noted during the disassembly which validated the engineering recommendation to not perform the periodic tear down of the injectors.

The inspector observed the setup and performance of the post-maintenance engine analysis. The data from the analysis was used to adjust the engine timing and to monitor cylinder pressures and engine horsepower. The procedure was well written and the technicians were knowledgeable concerning the use of the equipment and interpretation of the data. For example, they identified a faulty pressure sensor due to unexpected changes in the peak cylinder pressures. The probe was changed and adjustments were made to the new fuel injectors which resulted in the average peak pressure being closer to the vendor recommended average peak pressure.

The inspector determined that a 10 CFR 50.59 screening was not conducted by the licensee supporting this procedure change. Administrative procedure 01AC 0AP02, "Review and Approval of Nuclear Administrative and Technical Procedures," requires a 50.59 screening whenever a new procedure involves an intent change. Paragraph 4.1.13, number 5, specifies an intent change exists if the acceptance criteria is altered, but makes an exception if the change was directed as part an approved design output document. The maintenance standards group interpreted EER 92-DG-028 to be a design output document and therefore did not view it as an intent change. However, the procedure for conducting a EER does not require a 50.59 screening for this particular evaluation even though the acceptance criteria for a satisfactory surveillance test had been

changed. The inspector discussed the review process for new and revised vendor technical information with the licensee and determined that a 50.59 screening was not performed during that review. The inspector noted that vendor technical manuals are defined in licensee procedures as design output documents, and that the Output Document Change Request procedure requires a 50.59 screening, or a justification why one is not necessary. However, the licensee does not process vendor technical manuals as design output documents. Licensee management acknowledged that a 50.59 screening should have been performed at some point in the processing of the technical manual or procedure change, and initiated Condition Report/Disposition Request (CRDR) 9-2-0635 to investigate the possible programmatic weakness. The inspector will review the licensee's evaluation (Followup Item 530/92-35-01).

The inspector concluded that the engineering analysis and change to the surveillance procedure were appropriately implemented, but that a 10 CFR 50.59 screening should have been performed addressing the change. The inspector further concluded that the engine inspection observed was adequately performed.

No violations of NRC requirements or deviations were identified.

8. Quality Assurance Program - Units 1, 2, and 3 (35701)

The inspector reviewed Quality Assurance (QA) Audit Reports 92-004, "Refueling Operations," and 92-011, "Software Quality Assurance."

QA Audit 92-004, "Refueling Operations"

This audit was performed during the Unit 1 Spring 1992 refueling outage. The scope of the audit included management expectations, organization, destack activities, fuel handling activities, foreign material exclusion Zone III control, radiological work controls, training effectiveness, refueling technical specifications, contractor control, safety, and corrective action effectiveness.

Audit personnel paid particular note to communications and control issues as a result of significant deficiencies identified during the previous Unit 2 refueling (see Inspection Report 50-529/91-47). While the audit describes some problems identified by the working groups, QA personnel identified other items, including the inappropriate reliance on reactor engineers to ensure that various Technical Specification requirements were complied with, without licensed operator direct oversight.

QA personnel challenged a late-night decision by operations and engineering management regarding the interpretation of a procedure, demonstrating the resolve to take a firm position.

The conclusions of the audit were clearly communicated. The conclusions related to specific events and observations. However, the audit report did not provide overall insights from the audit findings.

The inspector concluded that the audit was adequate in scope and depth to accomplish its purpose.

QA Audit 92-011, "Software Quality Assurance"

This audit adequately addressed salient aspects of software QA, including management expectations, program adequacy and program application, for both non-process and process software. The audit identified several strengths and weaknesses, resulting in the initiation of two new Quality Deficiency Reports (QDRs), an additional action for an existing QDR, and eight Quality Assurance Recommendations (QARs). Notable conclusions of the audit included: 1) motor operated valve test software was not in compliance with the program, 2) some non-process software had not been reviewed for compliance with the new procedure 01PR-0CQ01, "Software Quality Assurance (SQA) Program for Non-Process Computer Software," 3) an index of quality software indicating approved version level and qualification status does not exist, and 4) the boric acid blending option of the BORON code has not been validated.

The audit also noted that process computer software is excluded from the recently issued Operations QA Plan, Appendix G. Additionally, procedure 77PR-9OC01, "Process Computer Software Control Program," was found to be administratively out of date. Numerous problems with Core Operating Limit Supervisory System (COLSS) software have been experienced at Palo Verde, two of which are described in the audit. While COLSS is not classified by the licensee as Quality Software, the problems have highlighted the need for additional attention to the quality of process computer software (see Inspection Report 50-528/90-28).

The audit pointed out that the licensee is developing a greater awareness of the need for quality assurance standards in software, though the applicability of specific standards has not been thoroughly addressed nor determined.

The inspector concluded that the audit was effective in identifying programmatic deficiencies, that it was adequate in scope and depth, and that it provided meaningful recommendations. The audit also summarized overall strengths and weaknesses to direct management attention appropriately. The inspector also noted that the licensee's intention of performing a similar audit next year is warranted.

Conclusion

The inspector concluded that the audit program, as represented by the two audits reviewed, is being effectively implemented. The integration of audit results into plant activities will be addressed in a future inspection.

No violations of NRC requirements or deviations were identified.

9. Licensee Response to Rosemount 10 CFR Part 21 - Units 1, 2, and 3 (92700)

On October 8, 1992, the licensee determined that a condition reported by Rosemount, concerning the span correction of some differential pressure transmitters, could affect the Core Operating Limit Supervisory System (COLSS) secondary calorimetric determination of power level. The Part 21 report affects 67 of 320 transmitters installed at Palo Verde, but the only impact on safety was determined by the licensee to be on the feedwater flow transmitters. The magnitude of the error potentially introduced by the reported condition was 0.19%, resulting in the COLSS calorimetric calculation indicating that reactor power was 100% when it was actually 100.19%. Because the reported error is a bias in a specific direction, it was not bounded by the 2% uncertainty of the COLSS calculation. Upon being informed of this conclusion by the engineering staff, licensee management ordered that the two operating units decrease power to 99.5% indicated power level to ensure that 100% actual power level was not exceeded. Power was restored to 100% after a COLSS addressable constant was changed to include an appropriate penalty factor. These actions were considered temporary, pending adjustment of the transmitters when plant conditions allow. The inspector concluded that the licensee's actions demonstrated thoroughness of engineering review and appropriate conservatism in management response.

No violations of NRC requirements or deviations were identified.

10. Followup on Previously Identified Items - Units 1, 2, and 3 (92701 and 92702)

a. Unit 1

(1) (Open) Followup Item 528/92-22-03, Reactor Trip Breaker (RTB) Troubleshooting Activities - Units 1, 2, and 3 (92701)

This item involved the failure of a General Electric (GE) RTB to close as discussed in Inspection Report 50-528/529/530/92-15. GE finalized their root cause of failure report on October 19, 1992, and concluded that shock generated during the closing cycle and transmitted to the trip shaft prevented the breaker from maintaining a fully latched position. This report did not contain corrective actions nor recommendations, and APS has not taken a final position on this issue. This item will remain open pending a review of the final APS position and actions.

b. Unit 2

(1) (Closed) Followup Item 529/92-22-02, Reactor Trip Breaker (RTB) Undervoltage Trip Assembly (UVTA) Issues - Units 1, 2, and 3 (92701)

This item involved the discovery of a deenergized UVTA armature in the mid-position, and not in the fully tripped position. This item was opened to review the final root cause of failure

report. The report was issued on September 9, 1992 and concluded that the root cause of failure was indeterminate. The suggested probable cause was debris in the UV device armature spring. This report recommended enhancing RTB recordkeeping, inspection of RTBs for debris, and enhanced procedural guidance for performing required adjustments and checking settings. ICRs have been submitted for all recommended procedural enhancements. Each GE AKR-30 breaker will be inspected for loose debris during the next scheduled maintenance. Training is evaluating changes to training to enhance instruction in adjusting the UV device. According to the plant engineer, the two year UVTA coil replacement will now require the replacement of the entire UVTA, and not just the UVTA coil. Based on the above, this item is closed.

c. Unit 3

(1) (Closed) Violation 530/92-15-01, Reactor Trip Breaker (RTB) Control of Troubleshooting - Unit 3 (92702)

This item involved the failure of the licensee to control troubleshooting on RTB "C" on March 31, 1992. This resulted in electricians cycling the breaker approximately 100 times without engineering involvement and may have resulted in the loss of some root cause of failure data. The licensee has expanded the requirements of procedure 70DP-0EE01, "Equipment Root Cause of Failure," to more clearly define when a quarantine is required. The Director, Site Technical Support, issued a letter to the plant managers and maintenance managers identifying situations which require early engineering involvement in troubleshooting activities. In addition, a critical systems, components, and activities list has been developed by an APS task force. APS is also developing a sensitive issues awareness list. The inspector noted two examples where a system engineer and a shift supervisor were not familiar with the requirements of 70DP-0EE01 shortly after revision 2.00 was issued. After reviewing revision 2.00 of 70DP-0EE01 and the letter regarding situations requiring early engineering involvement, the inspector concluded that adequate procedural guidance exists to prevent recurrence. The inspector encouraged the licensee to ensure that all personnel involved in troubleshooting are familiar with these new requirements. The inspector will continue to evaluate troubleshooting on an ongoing basis. Based on this review, this item is closed.

(2) (Closed) Unresolved Item 530/92-31-04, Spray Pond Pump "B" Section XI Test Failure - Unit 3 (92701)

This item concerned the apparent failure of the licensee to determine or document the cause of the deviation following the failure of the ASME Section XI test of the Unit 3 "B" spray

pond pump on September 10, 1992, prior to returning the pump to service on September 12, 1992.

Following a test in which the results are in the "required action" range, Section IWP-3230 of the Code requires that the pump be taken out of service, and the cause of the deviation be identified and corrective action completed prior to returning the pump to service. The inspector determined that the licensee believed that pump performance had not changed, and that earliest test data on which the reference differential pressure value was based was probably not determined under tightly controlled test conditions, as recent test data has been. Additionally, the licensee did not believe that the data from the failed test represented a pump performance change, but was the result of data scatter and an intentional increase in the flow rate for the test. The inspector noted that the licensee had not documented this understanding of the cause of the deviation, but had instead stated verbally, when asked, that the cause of the deviation was that the previous reference value was incorrect. The inspector also noted that the licensee initiated Condition Report/Disposition Request (CRDR) 3-2-0306 to document further evaluation of the test failure.

Discussions with NRR personnel confirmed that the Code requires that the licensee identify the cause of deviation of the failed data from the reference value. Simply stating that the reference value was incorrect does not address the intent of the Code to address the change in pump performance. The inspector noted that the licensee had not explicitly documented the cause of the deviation, hindering later verification of compliance with the Code. While the licensee's stated cause of the deviation was faulty, the inspector concluded that the licensee did have an understanding of the actual cause of the deviation. Additionally, the Code does not require the cause of the deviation to be documented. The inspector concluded that the licensee had satisfied all Code requirements, though documentation alone does not support the conclusion. The licensee agreed to review its administrative requirements to determine if changes were needed to ensure appropriate information is documented to support Code requirements.

Based on this review, this item is closed.

d. Units 1, 2, and 3

(1) (Closed) Followup Item 528/90-25-06: Emergency Lighting Vendor Information - Units 1, 2, and 3 (92701)

The followup item addressed the maintenance of vendor technical manuals associated with emergency lighting.

The inspector discussed the current status of emergency lighting technical manuals with the licensee's Vendor Manual section of the Procurement Engineering department. This group is charged with developing and maintaining new manuals for all plant equipment. New manuals, designated as Vendor Technical Manuals (VTMs), are being issued after all vendors are contacted to ensure that the licensee has the latest applicable vendor information for each plant component. Currently, three new emergency lighting vendor technical manuals have been issued:

VTM-D972-0001 Dual-Lite
Issued June 29, 1992. A revision was in process, due October 21, 1992, to incorporate system engineer comments. Output Document Change Requests were issued on October 12, 1992, addressing these comments. Also, two additional vendor documents will be incorporated.

VTM-H249-0001 Holophane
According to the licensee, this was issued July 1, 1992. A revision was in process, due October 15, 1992, to incorporate seven new vendor documents and to add new equipment identification numbers to the applicability list.

VTM-E355-0001 Exide
Issued February 21, 1992. This manual includes the Emergency Lighting (QD) system.

Three additional new VTMs are due to be issued by the end of 1992. One of these will be for the QD system, taking information out of VTM-E355-0001. The other two address the Sure-Lite and Siltron lights.

The licensee stated that new vendor information is screened promptly upon receipt. Information deemed to be very important to safety is incorporated within a few days. Other information is incorporated within either 30 or 60 days, dependent upon the screening results. The licensee stated that no backlog exists for any of the emergency lighting vendor manuals. Vendor information received which applies to the old vendor manuals is incorporated in those manuals on the same schedule. However, the old manuals have not gone through the verification process to ensure all appropriate vendor information has been identified and incorporated.

The inspector reviewed the Exide and Dual-Lite VTMs in the licensee's technical library and found them to be administratively clean and professional. The Holophane VTM was in use at the time. The inspector found no indication of a backlog of vendor information which had not yet been incorporated in the manuals. Additionally, the inspector

reviewed parts of the Station Information Management System (SIMS) database regarding technical manual information. The inspector reviewed a sample of equipment listed in the database and found that not all equipment had vendor manual information. For those pieces of equipment selected by the inspector which had vendor information, the database showed that the information had been verified by licensee personnel. Some equipment IDs (e.g., 1EQBND79 CKTBRK and 1EQBND84 5204 CKTBRK) did not indicate the applicable technical manual. The SIMS database is updated after issuance of the VTM, so this appeared to be consistent with the status provided by the licensee.

The inspector concluded that the licensee's emergency lighting vendor manuals are being appropriately maintained, and that the Vendor Technical Manual project is progressing satisfactorily to complete the issuance of verified VTMs for emergency lights.

(2) (Open) Unresolved Item 529/92-22-01, Annunciator Jumpers - Units 1 and 2 (92701)

This item involved a licensee program to interpret the work control and temporary modification procedures to permit the installation of temporary jumpers across inputs of defective field devices in the annunciator system without an engineering evaluation or 10 CFR 50.59 evaluation. The licensee extended the program to annunciators which had inappropriate setpoints and were therefore "nuisance" annunciators. The inspector noted a plant review board decision which required maintenance standards to incorporate this program in the nuclear administrative and technical manual as a procedure. The inspector further noted that maintenance standards was planning to only address the installation of jumpers for annunciators associated with inoperable equipment, and not those associated with "nuisance" annunciators. This item will remain open pending a review of the licensee program associated with "nuisance" annunciators.

(3) (Closed) Information Notice 92-06, Reliability of ATWS Mitigation System and Other NRC Required Equipment Not Controlled By Plant Technical Specifications - Units 1, 2, and 3 (92701)

The inspector reviewed the licensee's July 14, 1992, memorandum of recommended corrective actions to address the concerns of IN 92-06. Six actions were identified, as summarized:

- Evaluate functional and surveillance tests to ensure NRC commitments are being met. Ensure test frequency is adequate to maintain the diverse auxiliary feedwater actuation system (DAFAS) and the diverse scram system (DSS) in a reliable configuration.

- Develop appropriate preventive maintenance tasks.

- Develop controls to ensure proper priority is applied to return out-of-service systems to service in a timely manner.

- Develop a mechanism to ensure management is aware of anticipated transient without scram (ATWS) system status. Consider actions similar to Limiting Conditions for Operation (LCO), and Technical Specification Component Condition Record (TSCCR) tracking.

- Develop procedures to describe operations personnel responsibilities to control these systems, such as when they are placed in bypass.

- Develop and implement training to ensure operations and maintenance personnel are trained on the procedural requirements initiated to control ATWS systems.

The response to items 1, 2, and 3 is due September 30, 1992. Items 4 and 5 were addressed by requiring Plant Managers to report the DAFAS status to the Plant Review Board (PRB) monthly, and by revising the alarm response procedure to require a Condition Report/Disposition Request (CRDR) to be initiated if DAFAS is in test, bypass, or out-of-service for any reason other than an approved procedure, test, or approved work document. Item 6 will be initiated when the procedure changes are issued to training for incorporation into the training change system.

The inspector concluded that the licensee's review to date of this issue is adequate to address the concerns of IN 92-06.

(4) <u>(Closed) Followup Item 529/92-27-02, Verification of Plant Records - Units 1, 2, and 3 (TI 2515/115, 92701)</u>

This item involved the review of the licensee's investigation of Auxiliary Operator (AO) logs in response to Corrective Action Report (CAR) 92-0104, to determine if the licensee's self-monitoring detects practices that might result in falsified logs.

The licensee reviewed six logs for each of the 105 qualified AOs for inconsistencies with security access records. Although numerous discrepancies were identified, many were subsequently eliminated due to verifiable explanations. However, 27 individuals (7 from Unit 1, 13 from Unit 2, and 7 from Unit 3), on one or more occasions, were determined to have made log entries without having made entries into the required areas, without acceptable explanations (e.g., another qualified

operator made a verified entry). Examples of discrepancies are:

- Failure to enter spray pond pump room when pump was known to be inoperable

- Failure to enter the Main Steam Support Structure

- Failure to enter auxiliary feedwater pump room

- Failure to enter pipe chase to obtain hold-up tank gas analyzer condensate pot sight glass level

Each AO with identified discrepancies was interviewed at least once. Several AOs complained of problems with the security system, and these were each investigated by the licensee. In general, such complaints were not substantiated.

The discrepancies were divided into two categories based on seriousness. The more serious category required the documenting of a reading on the log sheet. The less serious category required a checkoff on the logsheet for having toured a given room. The licensee disciplined the AOs involved in unexplained discrepancies. None of the discrepancies involved Technical Specification requirements or NRC-licensed individuals.

The licensee also evaluated the root cause of the observed performance deficiencies and found that in several cases neither the AOs nor their supervisors clearly understood the performance expectations. Several supervisors were unaware of the practices used by the AOs, such as looking through grating to read a sight glass about 90 feet away. Additionally, procedural guidance was found not to be clear. The licensee revised appropriate procedures and took other measures to ensure that the expectations were explicitly understood.

The licensee's Quality Assurance department expects to perform some verification activities related to this issue on a periodic basis. Such a program was not in place prior to the emergence of this issue elsewhere in the industry earlier this year.

The inspector concluded that the licensee's investigation, and plans to continue to monitor these activities in the future, appeared appropriate.

This followup item and this temporary instruction are closed.

No violations of NRC requirements or deviations were identified.

11. Exit Meeting

An exit meeting was held on November 2, 1992, with licensee management and resident inspectors during which the observations and conclusions in this report were generally discussed. The licensee did not identify as proprietary any materials provided to or reviewed by the inspectors during the inspection.

PALO VERDE

INDEPENDENT SAFETY ENGINEERING

PRESENTATION

TO

NRC REGION V

NOVEMBER 2, 1992

- **CHANGES/ENHANCEMENTS FROM PAST PRACTICES**

- **ACCOMPLISHMENTS**
  - ASSESSMENTS COMPLETED, RESULTS AND RECOMMENDATIONS
  - OBSERVATIONS/MINOR ASSESSMENTS COMPLETED, RESULTS AND RECOMMENDATIONS
  - ASSESSMENTS PLANNED OR IN PROGRESS
  - EMPHASIS ON TRAINING
  - ACTIVITIES REQUESTED BY PVNGS SENIOR MANAGEMENT
  - MANAGEMENT FEEDBACK AND ACTIONS

- **CHALLENGES/WAY WE DO BUSINESS**

CHANGES/ENHANCEMENTS FROM PAST PRACTICE

- INCREASED AWARENESS OF AND SENSITIVITY TO PLANT ACTIVITIES
- INCREASED OVERVIEW OF FIELD ACTIVITIES
- MORE THROUGH AND DOCUMENTED REVIEW OF NRC, INDUSTRY AND IN-HOUSE OPERATING INFORMATION
- SCHEDULE FOR ASSESSMENTS
- AGGRESSIVE ASSESSMENT MANAGEMENT
- FORMAT OF ASSESSMENT REPORTS REVISED
- IMPROVED COMMUNICATIONS WITH NRC RESIDENT'S OFFICE
- EMPHASIS ON "OPERATIONS ORIENTED" TRAINING AND PERSONNEL WITH OPERATIONS EXPERIENCE
- EMPHASIS ON "TRUE INDEPENDENCE" IN ISE ACTIVITIES
- PERIODIC MEETINGS WITH PLANT MANAGEMENT

ACCOMPLISHMENTS

- ASSESSMENTS COMPLETED

  RESULTS AND RECOMMENDATIONS

  MANAGEMENT FEEDBACK AND ACTIONS INITIATED

- OBSERVATIONS/MINOR ASSESSMENTS COMPLETED

  RESULTS AND RECOMMENDATIONS

  ACTIONS INITIATED OR TAKEN

- ASSESSMENTS PLANNED

- EMPHASIS ON TRAINING

- ACTIVITIES REQUESTED BY PVNGS SENIOR MANAGEMENT

CHALLENGES/WAY WE DO BUSINESS

- CONTINUE TO REFINE PROCESS TO STAY ON TOP OF EMERGING ISSUES
- TO ENSURE A PROACTIVE APPROACH, USE ERROR MODES AND EFFECTS ANALYSIS TO REVIEW PLANS AND PROCEDURES FOR NON-ROUTINE/SPECIAL EVOLUTIONS BEFORE EXECUTION
- USE SSFI/VERTICAL SLICE ASSESSMENT TECHNIQUES IN THE CONDUCT OF "MAJOR ASSESSMENTS"
- DEVELOP CRITERIA FOR QUICKLY DETERMINING SIGNIFICANCE OF AND APPLICABILITY TO PVNGS OF EMERGING ISSUES AND INDUSTRY EVENTS (HANDBOOK LIKE TMI)
- STAFF COHESIVENESS (ROTATIONAL ASSIGNMENTS)
- RELATIONSHIP WITH PRA AND HOW WE ARE GOING TO USE IT

ACCOMPLISHMENTS

- ACCOMPLISHMENTS

- MAJOR ASSESSMENTS COMPLETED

  - FIELD EVALUATION 92-17, EVALUATION OF DEBRIS POTENTIALLY ENTERING THE REACTOR VESSEL

  - ASSESSMENT 92-21, INDEPENDENT REVIEW OF PVNGS RESPONSE TO NUMARC 91-06, "GUIDELINE FOR INDUSTRY ACTIONS TO ASSESS SHUTDOWN MANAGEMENT"

    - THE PRELIMINARY RESPONSES WERE INADEQUATE AND ISE PROVIDED DETAILED RECOMMENDATIONS FOR IMPROVEMENT

    - THIRTEEN AREAS WERE IDENTIFIED BY ISE WHERE NUCLEAR SAFETY IMPROVEMENTS COULD BE MADE

  - ASSESSMENT 92-22, COMPARISON OF QUALITY AND NON-QUALITY WORK ACTIVITIES

    - NO PROCEDURAL DEFICIENCIES WERE IDENTIFIED. THE SAME PROCEDURES APPLY TO BOTH Q AND NON-Q WORK. A "CULTURAL" DIFFERENCE IN TREATMENT OF Q AND NON-Q WORK WAS IDENTIFIED IN HOW THOSE PROCEDURES ARE IMPLEMENTED

  - ASSESSMENT 92-23, TECHNICAL SPECIFICATION VALVE ALIGNMENT

    - TWO AREAS WERE IDENTIFIED WHERE THE TECHNICAL SPECIFICATION SURVEILLANCE TEST MAY NOT HAVE MET THE INTENT OF TECHNICAL SPECIFICATION SURVEILLANCE REQUIREMENT

- RECOMMENDATIONS MADE AS A RESULT OF ASSESSMENTS
    - AN EVALUATION BE CONDUCTED TO DETERMINE THE NEED FOR ACQUIRING VIDEO EQUIPMENT TO EXAMINE THE REACTOR VESSEL THROUGH THE LOWER CORE SUPPORT PLATE FOR DEBRIS ACCUMULATION DURING OPERATION
    - AN EVALUATION BE CONDUCTED TO DETERMINE THE METHODS AND TOOLS NEEDED FOR RETRIEVAL OF FOREIGN MATERIAL LOCATED BY THE VIDEO EQUIPMENT
    - EVALUATE THE NECESSITY FOR:
        - PERIODICALLY VERIFYING SHUTDOWN COOLING SYSTEM RELIEF VALVES ARE ALIGNED PROPERLY WHILE IN MODES 4, 5, AND 6 AND IN STEADY STATE WITH REACTOR VESSEL HEAD TENSIONED
        - IDENTIFY VALVE POSITION FOR SPA-HV-49A/B AND HPB-HV-50A/B
    - REVISE PROCEDURE 51PR-0ZZ01, "CONDUCT OF FORCED OUTAGES," TO INCLUDE THE RESPONSIBILITY OF THE UNIT MANAGER FOR THE REVIEW OF IMPACT OF FORCED OUTAGE WORK ACTIVITIES ON RCS PERTURBATIONS
    - REVISE MAINTENANCE PROGRAMS AND PROCEDURES TO REQUIRE AN INCREASED LEVEL OF DETAIL FOR NON-QUALITY RELATED WORK PACKAGES.
    - ESTABLISH, CLEARLY COMMUNICATE, AND CONSISTENTLY ENFORCE STANDARDS AND EXPECTATIONS CONCERNING LEVEL OF DETAIL, CRAFTSMANSHIP, AND USE OF RESOURCES FOR QUALITY VS. NON-QUALITY AND PRIORITY VS. NON-PRIORITY WORK ACCOMPLISHMENTS

- OBSERVATIONS/MINOR ASSESSMENTS COMPLETED

  - OBSERVATION 92-0002 DOCUMENTED A REVIEW OF THE LOOSE PARTS VIBRATION AND MONITORING SYSTEM IN UNIT 1. A CRDR WAS ISSUED IDENTIFYING THAT THE DETECTORS/SENSORS MAY NOT BE POSITIONED AS REQUIRED BY RG. 1.133

  - OBSERVATION 92-0004 DOCUMENTED A REVIEW OF THE UNIT 2 SHIFT SUPERVISOR's LOG AND RESULTED IN THE ISSUANCE OF 2 QDRs IDENTIFYING THAT MNCRs WERE NOT ISSUED IN A TIMELY MANNER FOR ARD RELAY DRAWING DISCREPANCIES.

  - OBSERVATIONS 92-0005 THROUGH 92-0013 DOCUMENTED A REVIEW OF WORK CONTROL RELATED PROCE RES TO DETERMINE IF QUALITY AND NON-QUALITY WORK WAS HANDLED THE SAME. (SEE ASSESSMENT 92-22)

  - OBSERVATION 92-0016 THROUGH 92-0033 AND 92-0035 THROUGH 92-0036 DOCUMENTED A REVIEW OF RESPONSES TO NUMARC 91-06 GUIDELINES. THESE REVIEWS IDENTIFIED THAT SEVERAL RESPONSES WERE INADEQUATE. (SEE ASSESSMENT AN 92-21)

  - OBSERVATION 92-0034 DOCUMENTED A REVIEW OF TECH SPEC VALVE POSITION SURVEILLANCE FOR THE EW SYSTEM. A CRDR WAS ISSUED AS A RESULT IDENTIFYING THAT ALL VALVE POSITIONS MAY NOT HAVE BEEN VERIFIED. (SEE ASSESSMENT AN 92-23)

  - OBSERVATION 92-0037 DOCUMENTED A REVIEW OF AUDITS AND MONITORING ACTIVITIES TO DETERMINE WHY DEFICIENCIES IDENTIFIED IN LER 92-008, VALVE POSITION VERIFICATIONS, WERE NOT IDENTIFIED BY PREVIOUS AUDITS AND MONITORING. (SEE ASSESSMENT AN 92-23)

  - OBSERVATION 92-0038 DOCUMENTED A REVIEW OF WORK CONTROL GUIDELINE FOR CONTROL OF CONTROL ROOM NUISANCE ALARMS. THE RESULTS INDICATED THAT THIS GUIDELINE CONTAINS ALL NECESSARY CONTROLS AND SHOULD BE PROCEDURALIZED.

  - OBSERVATION 92-0039 DOCUMENTED A REVIEW OF DEFICIENCIES IDENTIFIED WITH ROSEMOUNT TRANSMITTERS IN MNCR 92-SG-9072 TO DETERMINE SAFETY SIGNIFICANCE

  - OBSERVATIONS 92-0040 THROUGH 92-0045, 92-0047 THROUGH 92-0050, AND 92-0052 THROUGH 92-0060 DOCUMENT REVIEWS OF UNIT 3 OUTAGE ACTIVITIES.

  - OBSERVATION 92-0051 DOCUMENTS A REVIEW OF CORRECTIVE MAINTENANCE PERFORMED ON TRAIN A CEDM

MOTOR GENERATOR SET WHICH INVOLVED WORK INSIDE AN ENERGIZED CABINET.

- MAJOR RECOMMENDATIONS

  - RECOMMENDATIONS MADE AS A RESULT OF OBSERVATIONS:

    - PROCEDURALIZE ADMINISTRATIVE CONTROLS FOR CONTAINMENT OPENINGS WHEN RCS LEVEL IS GREATER THAN 111 FEET.

    - PROCEDURALIZE THE MINIMUM HEIGHT THE UPPER GUIDE STRUCTURE CAN BE WITHDRAWN TO ASSURE CLEARANCE OF THE REFUELING POOL "O-RING" SEAL

    - PROVIDE A LIFTING DEVICE FOR THE ADV VALVE BOARD

    - LIGHTS SHOULD BE SCHEDULED TO BE INSTALLED IN THE UPPER GUIDE STRUCTURE STORAGE PIT PRIOR TO THE START OF THE REMOVAL EVOLUTION

    - ISE INITIATED CRDR 3-2-0340 TO DOCUMENT THAT TEMPORARY POWER CABLING WAS UNDERSIZED AND THE OVERCURRENT PROTECTION WAS INADEQUATE.

    - ISE OBSERVED THAT ELECTRICIANS WORKING NEAR ENERGIZED EQUIPMENT HAD OBJECTS STRAPPED AROUND THEIR NECKS WHICH HAD METAL COMPONENTS WHICH COULD SWING OUT AND CONTACT ENERGIZED COMPONENTS.

ASSESSMENT SCHEDULE

Schedule Name : ISE ASSESSMENT SCHEDULE - 1992/93
Responsible : S.G. PENICK
As-of Date : 26-Oct-92 Schedule File : C:\TL3\DATA\ISE3RD

Task Name	Start Date	End Date
ASSESSMENTS:	8-Jun-92	29-Oct-93
NUMARC 91-06 GUIDELINES	8-Jun-92	17-Aug-92
SAFETY VS. NON-SAFETY WORK	22-Jun-92	22-Jul-92
TECH SPEC VALVE SURVEILLANCES	20-Jul-92	31-Aug-92
U3 SHUTDOWN RISK	31-Aug-92	27-Nov-92
STATION BLACKOUT	3-Mar-93	3-May-93
BACKLOG REVIEW	6-Jul-93	31-Aug-93
ALARMS - CONTINUOUS	15-Jul-93	30-Aug-93
ATWS	7-Sep-93	29-Oct-93
SOLENOID ACTUATED DEVICES	4-Jan-93	26-Feb-93

92 / 93
Jul 1, Aug 3, Sep 1, Oct 1, Nov 2, Dec 1, Jan 4, Feb 1, Mar 1, Apr 1

Detail Task — (Started) — (Slack)
===== Summary Task — ===== (Started) — ===— (Slack)
▲ Milestone — ▸▸▸ Conflict — .. Resource delay

Scale: 1 week per character

TIME LINE Gantt Chart Report, Strip 1, Page 1

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Schedule Name : ISE ASSESSMENT SCHEDULE - 1992/93
Responsible   : S.G. PENICK
As-of Date    : 26-Oct-92    Schedule File : C:\TL3\DATA\ISE3RD
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93
May Jun Jul Aug  Sep Oct Nov Dec
3   1   1   2    1   1   1   1
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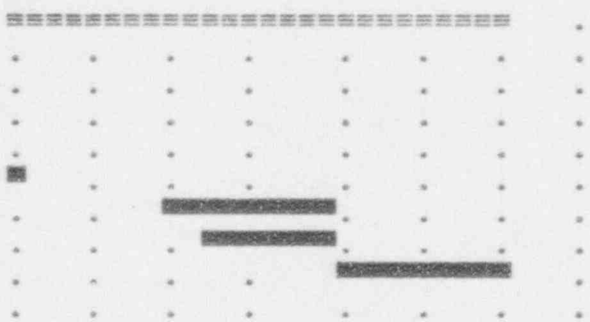

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----------------------------------------------------------------
■■■■■ Detail Task      ===== Summary Task      ▲   Milestone
..■■■ (Started)        ===== (Started)         ▶▶▶ Conflict
■■■— (Slack)           ===—— (Slack)           ..■■■ Resource delay
----------------- Scale: 1  week per character ----------------
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TIME LINE Gantt Chart Report, Strip 2, Page 1

REFUELING
OUTAGE
SCHEDULE

ISE U3R3 OUTAGE SCHEDULE
OCT. 26, 1992

Task Name	Notes	Keyword	1992 (Sep / Oct / Nov / Dec)
Tours & Safety Inspections		[illegible]	24-Sep-92 ▮ 24-Sep-92
OR 92-0040 Ind. Cont. Act.	SRT	—[illegible]/ELC	24-Sep-92 ▮ 24-Sep-92
[illegible] Prog		Con	19-Sep-92 ▬ 27-Nov-92
Loose Parts Monitor Sys.		Con	19-Sep-92 ▬ 27-Nov-92
[illegible] Test		Con	26-Sep-92 ▬ 30-Oct-92
OR 92-0041 Planning	SRT	—ELC	28-Sep-92 ▮ 28-Sep-92
Vibration Test		Con	30-Oct-92 ▮ 30-Oct-92
Scope Change Process		Con	19-Sep-92 ▬ 27-Nov-92
Tagging/Jumper Control		Con	19-Sep-92 ▬ 27-Nov-92
Mid-loop Operations		Con	4-Oct-92 ▮ 5-Oct-92
Review Refuel Pool Cleaning		[illegible]	19-Sep-92 ▬ 20-Oct-92
OR 92-0056	SRT	—[illegible]	19-Sep-92 ▬ 20-Oct-92
Selected Power T-[illegible]		[illegible]	28-Sep-92 ▬ 7-Oct-92
OR 92-0043 I-Pwr to [illegible] contr	[illegible] CRDR 3-2-0340	—[illegible]	28-Sep-92 ▮ 28-Sep-92
OR 92-0048 I-Pwr to I-PSN-[illegible]	SRT	—[illegible]	7-Oct-92 ▮ 7-Oct-92
[illegible] Terry Turb [illegible]		[illegible]	29-Sep-92 ▮ 29-Sep-92
OR 92-0047 Observe HP Turbine	SRT - F/U Scheduled	—[illegible]	29-Sep-92 ▮ 29-Sep-92
Insp. of [illegible]		Ferguson	5-Oct-92 ▬ 13-Oct-92
OR 92-0057	SRT	—[illegible]	5-Oct-92 ▬ 13-Oct-92
I-[illegible]		Ferguson	19-Sep-92 ▬ 20-Oct-92
[illegible]		Ferguson	27-Sep-92 ▬ 30-Oct-92
OR 92-0053	SRT	—[illegible]	27-Sep-92 ▬ 30-Oct-92
[illegible]		Ferguson	4-Nov-92 ▬ 8-Nov-92
[illegible]	Sched. [illegible]	[illegible]	29-Sep-92 ▮ 29-Sep-92
OR 92-0050 [illegible] observations	SRT - F/U Sched. 11/20	—[illegible]	29-Sep-92 ▮ 29-Sep-92
[illegible] Evaluation		[illegible]	30-Sep-92 ▮ 30-Sep-92
OR 92-0044 [illegible]	[illegible] F/U Sched. 12/[illegible]	—[illegible]	30-Sep-92 ▮ 30-Sep-92
[illegible]		[illegible]	19-Sep-92 ▬ 27-Nov-92
Main Turbine [illegible]		[illegible]	29-Sep-92 ▬ 2-Oct-92
OR 92-0042 Turb. Stop [illegible]	SRT - F/U	—[illegible]	29-Sep-92 ▮ 29-Sep-92
OR 92-0045 followup to 92-0042	SRT	—[illegible]	2-Oct-92 ▮ 2-Oct-92
[illegible] Containment Closeout		[illegible]	17-Nov-92 ◆ 17-Nov-92
[illegible]		Young	26-Oct-92 ▬ 4-Nov-92
[illegible] Removal	[illegible] - F/U Sched.	Young	9-Oct-92 ▮ 9-Oct-92
OR 92-0049 [illegible] Removal OR 92-5060	[illegible] 10/20, 92 4/15/93	—[illegible]	9-Oct-92 ▮ 9-Oct-92
[illegible] Eddy Current Tst		Young	1-Oct-92 ▬ 19-Oct-92

ASSESSMENT SUMMARIES

ISE FIELD EVALUATION 92-17
EVALUATION OF DEBRIS POTENTIALLY ENTERING THE REACTOR VESSEL

EXECUTIVE SUMMARY

INTRODUCTION

During a four month period from November 1991 through March 1992, four instances of metallic foreign material were documented that entered the Unit 1 and 2 reactor vessels. Broken pieces of the seal and backup rings from SI-657 entered the Unit 2 reactor vessel and broken pieces from SI-657, SI-658 and a "skyhook" inadvertently left in Steam Generator B tube sheet, entered the Unit 1 reactor vessel. Systems Engineering and Nuclear Fuels Management verified that this debris could have been small enough to have entered the core where fuel failure from fretting could not be ruled out. Ultrasonic testing performed on fuel in Units 1 and 3 during the last refueling outages indicated 34 and 4 failed fuel pins in each unit respectively. Ultrasonic and visual examination of the fuel indicated that two pins in Unit 3 and 1 pin in Unit 1 failed due to debris related fretting.

SCOPE

This field evaluation was performed:

- to confirm that foreign material which potentially damages fuel assemblies can accumulate in the reactor vessel despite controls that are in place to eliminate its intrusion and

- to review the actions that are ongoing which will further help reduce the intrusion of foreign material and enable the removal from the reactor vessel.

RESULTS

Strengths

The field evaluation concluded that SED determined the size and shape of missing parts and concluded that they probably reside in the reactor vessel. The EERs, MNCRs and CRDRs associated with these parts provided detailed analyses, and long term corrective actions for specific instances of failed equipment. The 10 CFR 50.59 Safety Evaluations accurately concluded that there is no safety concern.

Areas for Improvement

Areas for improvement include the need for development of the capability to detect and remove foreign material in the reactor vessel lower area, under the core support plate. This is where debris would accumulate over time and possibly break down into small pieces.

These pieces could enter the core and potentially damage fuel cladding.

RECOMMENDATIONS

It is recommended that:

- SED evaluate other valves similar to SI-657 and SI-658 to determine if similar failures exist where the seal material has entered the RCS

- In keeping with the Fuel Reliability Program, Operations Engineering-Refueling should evaluate the need for acquiring video equipment to examine the reactor vessel through the lower core support plate for debris accumulation during operation

- RP/Outage Planning evaluate methods and tools for retrieval of foreign material located by the video equipment.

CATS Items ISE 001086, 001087 and 001085 have been issued to the responsible organizations to address the above recommendation. SED is currently committed to inspecting the seats on valves similar to SI-657 and SI-658 in the (CT, EW, NC, DG, PW, SI, SP and TC) systems. This program is tracked as CATS Item 052706 (Partition OER).

CONCLUSIONS

ISE concluded that foreign material has entered the reactor vessel. The foreign material originated from components in service and from personnel oversight. Some of this foreign material is organic and it breaks down in the harsh environment of the reactor vessel and is removed by the CVCS system. Some of the foreign material may become lodged harmlessly below the fuel due to its dimensional characteristics, and some of it may enter the fuel flow channels, and potentially cause damage to the fuel. ISE is in agreement with the Nuclear Fuels Management in that, 1) the missing stainless steel seal ring parts could continue to break up into small parts due to fatigue fracture, and 2) the small missing parts of the skyhook could be entrapped in the fuel. In both cases, fuel failure from fretting cannot be ruled out.

ISE ASSESSMENT NO. 92-21
INDEPENDENT REVIEW OF PVNGS RESPONSE TO NUMARC 91-06, GUIDELINES FOR INDUSTRY ACTIONS TO ASSESS SHUTDOWN MANAGEMENT

EXECUTIVE SUMMARY

INTRODUCTION

At the request of the Unit 3 Manager of Outage Planning and Management (OPM), Independent Safety Engineering (ISE) independently reviewed the PVNGS responses for NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management." ISE attended committee meetings starting on June 16, 1992, and reviewed the available preliminary responses from August 4 through August 14, [illegible]

SCOPE

In reviewing the responses, ISE evaluated whether the complete NUMARC guideline was addressed, whether the response answered the guidance, whether the response provided sufficient detail and documentation to determine that the guideline is met, and if any areas existed which should be addressed to improve plant safety.

RESULTS

Strengths

Outage Planning Management

- took charge of ensuring NUMARC 91-06 was applied to 3R3 to the greatest extent possible even though the due date was December 31, 1992.
- requested independent ISE review for confidence in the quality of the response, and
- independently realized the inadequacies in the preliminary responses and took action for improvement in parallel with ISE's assessment.

Areas for Improvement

- A significant number of the preliminary responses were superficially conducted, resulting in incomplete or inaccurate documentation (20 of 67 responses), incompletely addressing the NUMARC guidance (22 of 67), or either not addressing or being inconsistent with the NUMARC guidance (22 of 67). One response was complete and accurate as submitted and had

no ISE comments.

- The significance of a commitment to NUMARC or a NUMARC initiative has not been communicated to the working level.

- The "Defense in Depth" concept of "Technical Specifications plus one" has not been adequately communicated from the groups preparing the Shutdown Risk Assessment to those implementing the outage, in particular Operations.

- Shutdown Risk Assessment Instruction Guide Appendix A does not have a "Key Safety Function" for dilution (reduction of Shutdown Margin).

- Procedures, supporting calculations and training are concentrated on mid-loop operations. There is significantly less detail available and in some specific cases no coverage in these three areas for the transition from normal loops filled Mode 5 operations to mid-loop operations (see Conclusions for details).

- PVNGS procedures require containment closure on a loss of shutdown cooling before core uncovery, which prevents any release of fission products. This is not conservative to the NUMARC guidance to use core boiling as the criteria. The use of core boiling as a criteria addresses radiological and environmental issues associated with the RCS steaming out the hot leg vent or refueling pool.

CONCLUSIONS

Detailed evaluation, comments, conclusions and recommendations to be used in improving the individual PVNGS responses are in ISE Observation Report Numbers 92-0003, 92-0016 through 92-0033, 92-0035 and 92-0036. These reports were provided to Outage Planning and Management on an as-completed basis during conduct of this ISE assessment to allow timely incorporation for the 3R3 outage.

The responses reviewed by ISE were the preliminary responses provided to OPM by the responsible organizations. OPM had not specifically screened them before ISE's review.. Also, only a few weeks

had been provided for the development of the responses. Not unexpectedly, the responses were generally superficial, incompletely documented, and frequently did not completely address the NUMARC guidance.

The significance of a NUMARC initiative or a commitment to NUMARC has not been communicated to the working level. The need to respond to the initiative was not put into CATS for tracking when the initiative was received by APS. In addition to the quality of the responses already described, in responding to the NUMARC guidelines, one organization noted that work had to be done on a "not to interfere with scheduled work" basis and no commitment was made to a schedule for "enhancements," one organization found some specific items unaddressed and made no commitment to address them, one organization took exception to guidance not already in place, and some organizations committed to action past the NUMARC implementation date.

The following are conclusions from ISE's evaluation which ISE considers significant and, when acted upon, should result in an improvement in nuclear safety.

- The "Technical Specification plus one" philosophy is only addressed as "Defense in Depth" in Appendix A of the Shutdown Risk Assessment Instruction Guide (i.e., does not appear by name and does not appear in an NATM procedure). The "Technical Specification plus one" philosophy has not been adequately communicated to the groups implementing the outage, in particular Operations (based on their response).

- Provision of plant/equipment status for outage personnel outside of the Control Room has not been procedurally provided for.

- Overtime policy exists for Nuclear Production and Site Technical Support personnel but is not procedurally covered for contractors performing safety- related work and APS personnel not in Nuclear Production or Site Technical Support performing work on safety-related or "Key Safety Function" equipment (e.g., the call out crew working on the transformer bushing in the

Unit 3 crane event).

- Abnormal Operating Procedures (AOPs) are in place for emergency boration, loss of shutdown cooling, loss of refueling pool/spent fuel pool level, and loss of AC power. No attempt has been made to match these to the Key Safety Functions developed and documented in Appendix A of the Shutdown Risk Assessment (SRA) Instruction Guide. An AOP should be available for loss of any Key Safety Function. In addition a Key Safety Function addressing dilution (inadvertent reduction of the required boron concentration for shutdown margin) needs to be added to Appendix A of the SRA Instruction Guide.

- Procedures, supporting calculations and training are concentrated on reduced inventory operations and, more specifically, mid-loop operations. This addresses the worst case scenario and guidance from NRC Generic Letter 88-17. There is significantly less detail available and in some specific cases no coverage between mid-loop operations and reduced inventory operations and between reduced inventory operations and normal operations. For example: acceptable time to shut containment penetrations is procedurally addressed for mid-loop operations but not reduced inventory operations; current supporting calculations for the procedures and core data books are only for mid-loop operations with a hot leg vent installed (although considered bounding, reduced inventory operations without a hot leg vent have not been addressed); and currently simulator training jumps from normal mode 5 to mid-loop operations when running the loss of shutdown cooling scenarios.

- Currently PVNGS procedures require containment closure for mid-loop operations before core uncovery (reduced inventory conditions above mid-loop currently have no procedural requirement as noted above). NUMARC guidance is to use core boiling when determining the time for containment penetration closure. Core boiling is more conservative but automatically addresses radiological and environmental issues associated with the RCS steaming out the hot leg vent or

refueling pool. These issues are not currently addressed at PVNGS other than by personnel evacuation of containment. The down side is that use of core boiling significantly reduces the time available for penetration or hatch closure (by about a factor of 8).

- The Shutdown Risk Assessment (SRA) currently does not procedurally address fire and flooding hazards posed by plant activities, system interactions, impact of temporary installed equipment, "single failures," returning equipment promptly to service, or use of periods of low decay heat, maximum inventory or defueled conditions. System interactions and temporarily installed equipment have been considered for the SRA but this is not in the instruction guide. Fire and flooding hazards were not considered in the past and the proposed schedule of 1R4 is not appropriate since this would leave 3R3 and 2R4 unreviewed. Per the response, "single failures" have not been considered and no commitment was made to consider these. Although single failures are partially addressed by the "Technical Specification plus one"/"Defense in Depth" process, this needs to be considered in properly developing "Contingency Plans." No commitment was made in the response to minimize windows by returning equipment to service promptly. No commitment was made in the response for use of periods of low decay heat, maximum inventory or defueled conditions (other than for 3R3) when going to reduced inventory conditions. These items should, at a minimum, be in the instruction guide for the Shutdown Risk Assessment.

- No connection is being made between Higher Risk Evolutions in the Shutdown Risk Assessment and Critical Evolutions in 40AC-9OP02, "Conduct of Shift Operations," even though PVNGS is taking credit for the briefings and other actions associated with Critical Evolutions in meeting the NUMARC guidance concerning Higher Risk Evolutions.

- Consideration should be made to expanding the disabling of the Shutdown Cooling Isolation Valve interlock from mid-loop operations to all reduced inventory operations. PVNGS has

had a loss of shutdown cooling (SDC) event due to inadvertent actuation of the SDC Isolation Valves at Unit 1 on May 23, 1989. A request for removal of the SDC Isolation Valve Interlock from the Technical Specifications is with the NRC. As an interim action, expanding disabling of the interlock to all reduced inventory operations would result in a decrease in the risk of a loss of shutdown cooling due to inadvertent closure of the SDC isolation valves.

- On a loss of shutdown cooling in mid-loop or reduced inventory operations, makeup using gravity feed from the RWT must be throttled so there is sufficient flow to prevent core boiling but not so much that the RCS overfills and spills out into containment or the RWT prematurely empties. There is no procedural guidance or supporting calculations/testing on where to position the throttled valve (the LPSI pump suction gate valve). This weakness was recognized during the completion of ISE recommendations for FE 19-29 and is being pursued by Nuclear Fuels Management and Operations Standards.

- The assumptions and initial conditions for the calculations supporting mid-loop/reduced inventory operations and loss of shutdown cooling should be provided to and used by PRA in performing the Shutdown Risk Assessment to ensure that planned activities do not invalidate these assumptions and initial conditions.

- Equipment loss due to flooding from a loss of Refueling Cavity seal was not addressed by the PVNGS response. While not considered a concern at PVNGS due to our low leakage rate, it needs to be addressed and documented since it has occurred at other plants and is part of the NUMARC guidance.

- Currently spare high voltage transformers are stored in a fenced area adjacent to the switchyard and high voltage transmission lines. Cranes are needed for the movement of these heavy components. Relocation of the spare transformers to a different storage area should be considered.

RECOMMENDATIONS

The following recommendations were discussed with the Unit 2 and 3 Managers of Outage Planning and Management and are assigned to the Fall Outage Manager:

- Provide the detailed comments and recommendations of ISE Observation Reports 92-0003, 92-0016 through 92-0033, 92-0035 and 92-0036 along with the NUMARC 91-06 response matrix to responsible department managers, to be addressed and incorporated into the final PVNGS response to NUMARC 91-06. Assign actions, on this basis, that will ensure comprehensive coverage of the guidelines, require specific documentation, and validation with specific due dates which are placed into CATS. This action is being tracked under CATS item ISE 001090 Action 01, with a due date of 10/30/92.

- Develop a response for addressing the thirteen specific ISE conclusions for improving nuclear safety in this assessment. This action is being tracked under CATS item ISE 001090 Action 02, with a due date of 10/30/92.

ISE ASSESSMENT NO. 92-22
COMPARISON OF QUALITY AND NON-QUALITY RELATED WORK ACTIVITIES

EXECUTIVE SUMMARY

Introduction

At the request of the Vice President, Nuclear Production, an independent team was formed to assess differences in quality related and non-quality related work at PVNGS. The assessment was performed June 22 through July 17, 1992. Independent Safety Engineering (ISE) was an active participant on that team.

Scope

The assessment scope included addressing the following questions asked by the Vice President:

- Are there programmatic/procedural differences?
- If so, what are the differences?
- Based on how work is actually done, are we following the program?
- Are we interpreting too much into the program?
- Is there a culture that people treat non-quality related work differently and less significantly than quality work?

Results

The independent review team's report is attached as Attachment A. This ISE Assessment documents the independent review team effort for ISE. The results of the team effort are summarized below.

Weaknesses

- Non-quality related work is the first to be deferred during scheduling conflicts.
- Non-quality related work packages are not always developed to the same level of detail as quality-related packages because of the room for interpretation allowed by the procedures.

- There is not a clear, consistent message being sent down through the organization as to the level of detail that is acceptable for non-quality related work packages.

Conclusions

A brief summary of the answers to the questions follows. See the ISE Assessment or team report for greater detail.

- *Are there programmatic/procedural differences?* Yes. The differences that exist are those necessary for the proper inspection and documentation of quality class activities and those due to perceived importance. The same procedures are used for both quality and non-quality related work activities and specified differences are few and narrow in scope.

- *If so, what are the differences?* ISE found seven procedural differences which were not based on code or QA Program requirements. See the conclusions in this assessment or the team report for details.

- *Based on how work is actually done, are we following the program?* Yes, but refer to the next question.

- *Are we interpreting too much into the program?* Yes. The differences ISE and the team observed in the field can be attributed to interpretation of the existing procedures, resulting in a difference in the level of detail in the work packages.

- *Is there a culture that people treat non-quality related work differently and less significantly than quality work?* Yes. See discussion below.

Although personnel perceive the work being done at PVNGS as being accomplished to a high standard of craftsmanship, work packages are not always written with the same level of detail for similar quality related and non-quality related jobs. Most craftsmen performing the work generally believe there is no difference in how they accomplish the work, even though the instructions may differ. The same PVNGS programs and procedures are used for quality and non-quality work, but they allow for differences in how quality related vs. non-quality related work is accomplished. Differences between quality and non-quality work activities not driven by the QA program, regulations or codes should be minimized.

Finally, the team noted instances where the field personnel took exception to QC involvement in non-quality related work activities and did not understand or accept the fact that QC can be involved with non-quality related work.

Recommendations

Because the procedure differences were limited, the team did not see the procedural differences as a major concern and recommended that the programs and procedures not undergo extensive revisions, but more appropriately that standards and expectations be clearly communicated and consistently enforced throughout PVNGS.

The following specific recommendations were made within the body of the team report:

- Revise maintenance programs and procedures to require an increased level of detail for non-quality related work packages. Revising the seven specific procedural differences (identified by ISE) would enhance the quality of non-quality related work packages.

  If it is a good idea to perform an activity in quality related work, it is a good idea for all work unless the activity is based on codes, regulations or Quality Assurance program requirements. If there is a documented verified skill possessed by all personnel in a craft, then that skill applies to all their work.

- Establish, clearly communicate, and consistently enforce standards and expectations concerning level of detail, craftsmanship, and use of resources for quality vs. non-quality and priority vs. low priority work.

- Ensure that the standards and expectations are clear, consistent and understood.

- Ensure that planning and scheduling put the correct priority on all work.

- Ensure that all maintenance personnel are aware of the "graded" approach to QC oversight. Also ensure that they understand that QC is not limited as to what they inspect. The message must be clear that we are only trying to improve how we do business through our observations and our own "critical self-assessment."

- Review the differences between quality and non-quality related engineering work activities with the goal of reducing any differences not specifically required by codes or the QA Program.

ISE ASSESSMENT No. 92-23
TECHNICAL SPECIFICATION SURVEILLANCE VALVE ALIGNMENT

EXECUTIVE SUMMARY

INTRODUCTION

As a corrective action to address events similar to those identified in Licensee Event Report (LER) 92-008, "Surveillance Requirement for Nonessential Auxiliary Feedwater Pump Not Performed," Unit 1, dated 5/8/92, Independent Safety Engineering (ISE) performed an evaluation to verify that the Technical Specification (TS) surveillance procedures for valve alignment included all the valves required to be checked per the applicable TS surveillance requirements (SR). Additionally, ISE made a determination as to why previous audits and reviews of the TS surveillance program did not discover the problem addressed in the LER.

> LER 92-008, Section IV, Previous Similar Events states in part: "...A review will be conducted to verify that the TS surveillance testing procedures for valve alignments include all the valves required to be checked in the applicable TS SRs." and "...The review will also attempt to ascertain why previous audits and reviews of the TS surveillance program did not discover these omissions."

SCOPE

A total of 47 Technical Specification surveillance requirements were identified by ISE that require verification of proper valve alignment. All 47 TS surveillance requirements were evaluated against the applicable TS surveillance test procedures to verify the valve alignment met the intent of the TS surveillance requirements. Additionally, ISE evaluated previous audits of the TS program and interviewed members of the Quality Audits and Monitoring Department.

RESULTS

Areas for Improvement

In general, the surveillance test program meets the technical specification surveillance requirements. However, the established program provides the minimum level of action necessary to meet the regulatory requirements. For example: Palo Verde verifies only those valves in a specific flow path to meet the intent of a TS requirement. ISE believes that not only should the flow path valves be verified, but also the valves for components and subsystems that support the system to ensure operability.

CONCLUSIONS

The assessment disclosed two areas where the TS surveillance test may not meet the intent of the TS surveillance requirements.

TS #4.7.3.a. and 4.7.6.1 require operability be verified by verifying valves servicing safety related equipment are in their correct position. However, some valves in support or interface systems or components are not verified by the associated ST. To address this concern, CRDR #92-0472 was issued for TS #4.7.3.a and TS #4.7.6.1 was added later in the review. Operations took conservative action and verified the valves listed in the CRDR were in their correct position. The preliminary response to the CRDR suggests that the ST is adequate to meet the intent of the TS. See Attachment B, CRDR #92-0472 and Attachment A, [illegible] Observation Report 92-0034.

A detailed evaluation of the 47 surveillance requirements is on file and available from ISE.

The assessment of the previous audits and reviews revealed that some technical problems have been identified; even though, the emphasis of past audits and reviews were on programmatic and procedural compliance. As an example, the problem addressed in LER 92-008 was identified by Quality Audit and Monitoring (QA&M) personnel while reviewing a proposed revision to a surveillance test procedure. Since the audit and monitoring activities review only a cross section of an overall area, QA&M, as an oversight group, is not always in a position to identify problems in all programmatic and technical areas. However, to enhance its abilities to identify technical problems, QA&M has emphasized hiring individuals with nuclear plant operating experience (RO/SRO). Additionally, the scope of future audits will be reduced to increase the level of detail for the review.

RECOMMENDATIONS

- ISE recommends a conservative approach to the issue addressed in CRDR #92-0472. ISE believes that all associated systems or components must be available for a system to be considered operable. Therefore, the boundary valves that are not verified in the current program and whose function is necessary should be included in the applicable surveillance test.

- TS #4.4.8.3.1 requires each shutdown cooling system suction (SCS) line relief valve be verified to be aligned every eight hours to provide overpressure protection for the RCS when the RV head is installed and the RCS temperature T_c <255°F during cooldown or <295°F during heatup. The only document that checks these valves is 40ST-9RC01, which requires the valves be checked every six hours during heatup and cooldown. Due to the significance of pressurized thermal shock (PTS), plant parameters are to be maintained within the limits of TS 3.4.8.1; therefore, these SDC reliefs must be in service when the reactor vessel head is installed to prevent exceeding the pressure limitations at a low reactor coolant temperature. Although not a TS requirement, to improve nuclear safety ISE recommends periodic verification of these valves while at steady state, in Modes 4, 5 and 6 when the reactor vessel head is installed.

  Surveillance Requirement 4.4.8.3.1 has an approved change effective September 16, 1992. The change has the shutdown cooling system suction line relief valve verified aligned once per 31 days when the pathway is provided by a locked open valve during cooldown ≤214°F and heatup ≤291°F with the reactor vessel head tensioned (12 hours if the pathway valve is not locked). In implementing the revised requirement ISE recommends conservatively including periodic verification of these valves while in steady state conditions with the reactor vessel head tensioned.

- TS #4.7.1.2.a.2 requires the Auxiliary Feedwater pump (AFP) associated flow path be verified every 31 days, while in Modes 1-4. The valves in the Main Feedwater System that are in the flow path of the non-essential AFP are not specifically checked in 4XST-XAF03, as referenced in 73DP-XZZ01, "Technical Specification Surveillance Requirements Cross Reference - Unit X." However, these valves are verified in 40ST-9AF06. ISE recommends that 73DP-XZZ01 be reviewed to verify the proper ST procedures are referenced for TS #4.7.1.2.a.2.

  Operations Standards was aware of this discrepancy and has

initiated documentation to resolve this recommendation. No further action is required.

- TS #4.7.4.2 requires two essential spray pond loops operable by verifying locked valves in their correct position once per 18 months during shutdown. The required position for SPA-HV-49A/B and SPB-HV-50A/B is "Manual Handwheel Locked," which is not a valve position. ISE recommends identifying SPA-HV-49A/B and SPB-HV-50A/B in an open or closed position for better control of the valve position.

INDEPENDENT SAFETY ENGINEERING

MISSION STATEMENT

ISE MISSION STATEMENT

ISE'S MISSION IS TO AID IN THE IMPROVEMENT OF NUCLEAR SAFETY AT PALO VERDE BY PROVIDING RECOMMENDATIONS TO APPROPRIATE MANAGEMENT AND ADVISING MANAGEMENT ON THE OVERALL QUALITY AND SAFETY OF OPERATIONS.

TO PERFORM THIS MISSION, ISE:

PERFORMS INDEPENDENT ASSESSMENTS OF PLANT ACTIVITIES INCLUDING OPERATIONS, MAINTENANCE, AND MODIFICATIONS;

MAINTAINS SURVEILLANCE OF PLANT OPERATIONS AND MAINTENANCE ACTIVITIES TO PROVIDE INDEPENDENT VERIFICATION THAT THESE ACTIVITIES ARE PERFORMED CORRECTLY AND THAT HUMAN ERRORS ARE REDUCED AS FAR AS PRACTICABLE, AND TO DETECT POTENTIAL NUCLEAR SAFETY HAZARDS;

EXAMINES NRC ISSUANCES, INDUSTRY ADVISORIES, LICENSEE EVENT REPORTS, AND OTHER SOURCES OF PLANT DESIGN AND OPERATING EXPERIENCE INFORMATION, INCLUDING PLANTS OF SIMILAR DESIGN, WHICH MAY INDICATE AREAS FOR IMPROVING PLANT SAFETY; AND

AIDS IN THE ESTABLISHMENT OF PROGRAMMATIC REQUIREMENTS FOR PLANT ACTIVITIES.

JUNE 23, 1992

INDEPENDENT SAFETY ENGINEERING

MANAGEMENT EXPECTATIONS

APS

Arizona Public Service Company
COMPANY CORRESPONDENCE

ID #: 023-03642-RNP

Date: October 13, 1992

To: ISE Staff
Sta.:
Ext.:

Concurrence: SGuthrie
Stephen C. Guthrie

From: Ram N. Prabhakar R. N. Prabhakar
Sta.: 7997
Ext.: 82-5991

FILE: 92-172-419

Subject: Management's Expectations for Independent Safety Engineering

INTRODUCTION

You have, from time to time, raised questions as to how we can effectively meet the intent of PVNGS Technical Specifications for ISE (Section 6.2.3), to the satisfaction of both PVNGS management and the NRC. Another question you have asked is regarding the distinction between QA Monitoring and ISE roles when some of the activities appear to overlap. Another ongoing concern is the amount of time ISE engineers are expected to spend in the field overviewing activities as outlined in the Technical Specifications.

In this memo, I will attempt to answer your questions and also lay out some broad expectations for the ISE group. If you still have questions on these or other related issues, please do not hesitate to contact me.

DISCUSSION

The ultimate measure of effectiveness of any oversight organization, such as ISE, is to help run an operation where there are no incidents that create nuclear safety hazards or contribute to situations that challenge safety systems. Obviously, we all know that when humans and machinery are involved, such incidents are unavoidable. It would be great if we had a crystal ball which would tell us exactly where the next safety significant event is going [illegible] place so that we can take appropriate measures in advance to preclude the occurrence of that event [illegible] facility. Once again, you and I both know that is wishful thinking. The next best thing we can do, as an oversight organization, is to have or develop the foresight, wisdom and the capability to evaluate incidents that have happened both at our plants as well as others, and to come up with effective ways and means of preventing such incidents at our facility. This is where Section 6.2.3.1 of Technical Specifications comes into the picture. This section requires that ISE function to examine plant operating characteristics, NRC issuances, industry advisories, Licensee Event Reports and other sources of plant design and operating experience information, including plants of similar design, which may indicate areas for improving plant safety.

Next, let us briefly examine the role of ISE and QA Monitoring and discuss how these functions are to be accomplished to avoid duplication of effort. ISE's role is one that should be "proactive" in nature. The emphasis is on taking appropriate steps to preclude safety significant incidents from occurring. In general, ISE's role should be "real time" , either forward or backward looking with great flexibility to look "into" issues anywhere they find them. ISE has a higher level of oversight with greater responsibility. QA Monitoring's role, on the other hand, is not mandated by Technical specifications and is intended to be accomplished by a group of discipline experts who conduct their observations in the field, assessing performance against an established scope. With that distinction being made between ISE and QA Monitoring's functions, ISE's activities should be geared towards reviewing up front, plans and procedures for plant evolutions and activities that are either conducted infrequently or that are of a highly specialized nature, with the intention of identifying procedural steps or activities that may compromise nuclear safety or cause human errors to be made. A technique that can be usefully employed here is the Error Modes and Effects Analysis, used during the Shutdown Risk assessment of Unit 1 conducted during the early part of the year. Again, this does not mean that the ISE Engineer is going to sit at his desk and perform all these reviews and issue reports. On a routine basis, ISE engineers should select high risk or non-routine evolutions in the operations, maintenance and modification areas for observation while they are being performed. Many times, this will be the only way to identify problems/inadequacies/deficiencies that may not be obvious to the performer or become apparent during up front reviews. When activities are selected by ISE for observation, it is important that communications be established with QA Monitoring (and QC, where appropriate) to ensure no duplication occurs.

Again, as an oversight organization, it is of vital importance that we maintain independence of our actions and be objective in our evaluations and assessments. Guidance and expectations included in this memo are not to be considered all inclusive. Many times, you will have to go where your instincts lead you based on careful observation techniques.

With this much as background material, let me lay out my expectations for the ISE staff.

MANAGEMENT EXPECTATIONS

1. By attendance at the Daily Plant Status Meetings, review of work activity schedules and discussion with plant staff, identify key evolutions that may have nuclear safety significance or has a potential for creating human error during their execution. As part of this process, ISE should periodically look at the impact and significance on the plant of safety equipment taken out of service and scheduling of high risk work activities. Another area worth pursuing is the scheduling of work activity on energized electrical equipment to determine if a conscious determination has been made as to the need for performing that activity in that state and the consequences on plant safety of any human error. Also, as part of this process, I would expect that at least one activity per week per unit will be selected for observation by the ISE engineers using the guidance I have provided under the Discussion part to eliminate duplication between ISE and QA Monitoring.

   Another aspect that should not be ignored is the selective overview of backshift activities. As experience, time and again has shown, that's when the most serious problems appear to take place in nuclear power plant operation. I would expect that each ISE engineer perform an overview of at least one backshift activity per quarter.

2. By review of unit outage schedules, determine key activities that will benefit from an ISE overview from the standpoint of precluding nuclear safety significant incidents. This should include operations, maintenance and modification activities. The emphasis here, as stated earlier, is for the ISE organization to take a proactive, forward looking role and review the plans and preparations for the evolution prior to execution, as against Monitoring's (or Quality Control's) role, which is one of ensuring compliance using performance based techniques. For those evolutions, where it is desirable for both the ISE and the Monitoring organizations to be involved during their execution, agree up front with QA Monitoring (and QC Inspection, when applicable and necessary) as to each organization's role, to avoid duplication of effort.

   Again, it is important to remember that during outages, although ISE's coverage of the outage unit may be more than that of the non-outage units, attention should continue to be given to the non-outage units.

3. The effective implementation of items 1 and 2 noted above will result in a significant amount of field time for the ISE staff. ISE's visibility and involvement with plant activities are important and field time is an indication of that. Field time does not exclusively include the time you spend overviewing implementation of evolutions or work activities, but also includes the time you spend with the Operations and Maintenance staff, reviewing plans, procedures, performing field walkdowns, etc. It is anticipated that activities described in 1 and 2 above will result in a field time of anywhere from 30 to 40% of each of your time.

4. Proper and effective implementation of items 1 and 2 should result in ISE Observations documented as Minor Assessments. My expectation is that, on an average, a minimum of four such Minor Assessments per engineer should be completed during the month.

5. Perform or participate in the performance of Major Assessments, as directed by ISE Supervision and Management. No more than four Major Assessments will be planned for during any calendar year.

6. Performance of observations and assessments may, at times, result in the identification of unsatisfactory areas. A concern has been expressed as to ISE's role regarding identification of problems and subsequent tracking of their resolutions, as this process may take ISE's time away from a true oversight function. I do not believe there is any question in your minds as to the need for documenting issues and concerns via appropriate mechanisms, when they arise. I also do not believe that you would want to identify a problem and not be concerned with how it was resolved to ensure prevention of recurrence. You must therefore, plan and manage your activities in such a way that you can allocate time for this important verification activity. You must make sure that this does not consume extensive amounts of your time. If you have other suggestions, please discuss with me.

7. Perform reviews of your assigned industry/operating experience information, clearly with the intent of flagging items of safety significance having impact on or applicability to Palo Verde. As part of this process, ISE engineers will be expected to make recommendations for enhancing nuclear safety at Palo Verde.

RNP/cdd

cc:	W. F. Conway	9082	S. G. Penick	7997
	R. C. Fullmer	7996		
	C. N. Russo	7992		
	R. B. Cherba	7995		
	T. C. Stewart	7960		
	M. D. Ferguson	6792		

MANAGEMENT FEEDBACK

APS

Arizona Public Service Company

COMPANY CORRESPONDENCE

ID #: 023-03604-RNP

DATE: July 17, 1992

TO: S. C. Guthrie
Sta #: 7992
Ext: 82-5810

FROM: R. N. Prabhakar
Sta #: 7997
Ext: 82-5991

FILE: 92-005-726

SUBJECT: INDEPENDENT SAFETY ENGINEERING ACTIVITY REPORT - JUNE 1992

Compliments! Good work

7/15/92

Attached please find the Independent Safety Engineering (ISE) Activity Report for June 1992.

Any suggestions for improvement of format or content of this report are most welcome. Also if there are any questions on any aspects of the report, please contact either myself or Steve Penick at extension 6629.

RNP/SGP/tes

cc:

W. F. Conway	9082
J. M. Levine	7602
R. J. Stevens	7603
E. C. Simpson	7616
R. E. Gouge	7610
W. E. Ide	7194
R. K. Flood	7294
R. J. Adney	7394
G. R. Overbeck	7546
K. W. Hamlin	1536
P. J. Caudill	7818
C. D. Mauldin	7610
E. W. Dotson	7694
J. A. Bailey	1875
A. C. Rogers	[illegible]
B. S. Ecklund	1560
T. R. Bradish	7636
D. H. [illegible]	7078

cc: Steve Guthrie
Steve Penick
Congratulations to you & your staff for a job well done.
- Ram P

⇒ Orig: Steve
cc: Steve Levine

August 31, 1992

To: Ram Prabhakar

From: Jim Levine

I appreciate the efforts by ISE in their recent review of our response to items in NUMARC 91-06. The results of your review show that this was not an adequate effort at all on our part. The only good point is that it was caught internally and with enough time left to fix it.

I do have a question, however, on one statement in your report. At the top of page 3 you state "...Not unexpectedly, the responses were generally superficial, incompletely documented and frequently did not completely address the NUMARC guidance."

I am curious as to why you believe this is "not unexpectedly". My expectations are that when we do a review it be thorough and comprehensive. Your statement would lead me to believe that superficial work of this nature is commonplace. Is this the case? If so, I would like to discuss other examples so that I can personally address them with the appropriate individuals.

Please respond by September 15, 1992.

JML/nar

cc: Bill Conway
Bob Adney
Ron Flood
Dick Gouge
Steve Guthrie
Bill Ide
Bert Simpson
Ron Stevens

Jim/nar

→ incomplete/inadequate responses. There was no reason for the use of the phrase. "Not unexpectedly". We will provide a response to Jim. This & will cc you

Ram —

I'd be interested in your answer as well — Does it refer to the "preliminary" status of the response?
Steve
9/2

Re: I briefly discussed this w/ Jim prior to the 9 a.m. meeting. Upon reflection, I agree we should/could have worded that differently (poor choice of words). But where we were coming from is the written fact that the people at the working level did not have an understanding of what NUMARC guidelines (& our commitments to meeting them) are and hence the

To: Ram N. Prabhakar@NoAnnex2@NoAnnex2
SSWGate@Server 44@Servers[APSVMB60.SGUTHRIE]
Cc:
Bcc:
From: Robert J. Adney,
Subject: ISEG
Date: Friday, September 11, 1992 at 12:47:00 pm
Attach:
Certify: N
Forwarded by: Ram N. Prabhakar@NoAnnex2@NoAnnex2

Comments by: Ram N. Prabhakar@NoAnnex2@NoAnnex2
Forwarded to: Stephen G. Penick@NoAnnex2@NoAnnex2
Comments:

FYI AS DISCUSSED. LET'S DISCUSS THIS TOMORROW. TX

------------------------- [Original Message] -------------------------

To: RPRABHAK--BANYAN PRABHAKAR, RAM N.
cc: Z99652 --APSVMB60 GUTHRIE, STEPHEN C

FROM: Robert J. Adney, U/3 Plant Manager
STA: 7394
EXT: 2520
Subject: ISEG
RAM, I HAVE BEEN PONDERING THE CHANGES GOING ON IN THE OVERSIGHT DEPTS. AND I BELIEVE THERE IS AN AREA THAT WE AS AN ORGANIZATION SEEM TO OVERLOOK. WHEN EVER WE HAVE PROBLEMS WE SEEM TO NARROWLY FOCUS ON THE PIECE OF DOCUMENTATION, EQUIPMENT, OR PART THAT HAS A PROBLEM AND NOT ENOUGH ON THE OVERALL SAFETY OF THE PLANT AS A WHOLE. I FEEL WE FIX ONE THING WHILE WE CREATE ANOTHER PROBLEM. IT CAN BE CALLED RISK MANAGEMENT, BALANCING THE VARIOUS HAZARDS, HAZARD PREVENTION, ETC. FOR EXAMPLE WE HAD A RECOMMENDATION FROM ENG. TO CHANGE OUT A FWIV 4 WAY VALVE. THEY WERE COMPLETING A ROOT CAUSE AND FELT THAT ONE OF OUR VALVES MAY BE UN-RELIABLE. IN ORDER FOR US TO CHANGE OUT THIS VALVE WE MUST ENTER A 4 HOUR ACTION STMT. AND THEN START A SHUTDOWN IF YOU CAN'T RESTORE OPERABILITY. WE FOCUSED ON THE 4 WAY VALVE AND NOT ENOUGH ON WHAT I CALL A BALANCED APPROACH TO SAFETY. THERE WAS ANOTHER ISOLATION VALVE IN SERIESWITH THE VALVE IN QUESTION, ANY DOWN POWER MANEUVER WOULD CAUSE A COMPLETE SHUTDOWN BECAUSE OF OUR TIME IN LIFE. ANY TIME WE DRIVE THE PLANT DOWN WE RISK SOME TYPE OF TRANSIENT AND CHALLENGES TO OUR SYSTEMS. WE ALSO HAD APPROX 10 DAYS LEFT TO OPERATE. IN BALANCE I BELIEVE WE WERE NOT MAKING THE BEST DECISION. THE MOST CONSERVATIVE IN NOT ALWAYS THE BEST. IF THAT WAS THE CASE WEWOULD NEVER ACTIVATE THE CORE AND CREATE A POTENTIAL HAZARD, I KNOW THAT THIS IS AN EXTREME EXAMPLE BUT WE MUST BE ABLE TO MAKE REASONABLE EVALUATIONS IN THE WHOLE. I BELIEVE THAT YOU AND YOUR DEPT. CAN HELP US SEE THE FOREST THROUGH THE TREES. DURING YOUR DEPT. DAILY VISITS I WELCOME THEM TO LISTEN FOR ISSUES THAT TAKE SAFETY EQUIPMENT OUT OF SERVICE TO MAKE IT "BETTER" AND ADVISE ME OF THE WISDOM OF DOING SO. THANKS FOR LISTING, BOB.

SAFETY - COST - PRODUCTION - PROFESSIONALISM

To: Stephen G. Penick@NoAnnex2@NoAnnex2
Cc:
Bcc:
From: Robert J. Adney,
Subject: ISE CUSTOMER QUESTIONS
Date: Sunday, October 18, 1992 at 12:27:00 pm
Attach:
Certify: N
Forwarded by:

To: SPENICK --BANYAN PENICK, STEPHEN G.

FROM: Robert J. Adney, U/? Plant Manager
STA: 7394
EXT: 2520
Subject: ISE CUSTOMER QUESTIONS
HELLO STEVE, THAT'S FOR TAKING THE TIME TO INQUIRE ON YOUR PERFORMANCE. I BELIEVE THAT YOUR GROUP IS HEADING IN THE RIGHT DIRECTION, THEY ARE GETTING MORE INVOLVED IN THE DAY TO DAY ACTIVITIES AND THE THOUGHT PROCESS THAT IS BEHIND THE DECISIONS. THE FORMAT OF THE REPORTS AND THE CONTENTS ARE APPROPRIATE AND OBJECTIVE. I BELIEVE THAT THE DEPT. NEEDS TO ESTABLISH A LINE OF COMMUNICATIONS WITH THE PLANT AND PERFORMANCE ENG. GROUPS. THEY HAVE SET NEW GOALS FOR THEM SELVES AND I BELIEVE THAT A MUTUAL UNDERSTANDING OF MISSIONS AND GOALS IS THE RIGHT THING TO DO. YOU MAY ALREADY HAVE SET UP DIALOGUE WITH THE ENG. ARM OF THE STATION, IF SO WELL DONE. IF NOT I RECOMMEND THAT YOU DO.I WOULD LIKE YOU TO PERFORM AN EVALUATION OF THE MOV PROGRAM. THIS PROGRAM HAS HAD A SIGNIFICANT AFFECT ON THE ENTIRE STATION AND ESPECIALLY OUTAGES. I BELIEVE WE NEED A FRESH LOOK AT THE BASIS FOR OUR PROGRAM, AND QUESTION WHY WE DO SOME OF THE THINGS AND IF IT IS THE MOST EFFECTIVE USE OF OUR RESOURCES. FOR EXAMPLE WE DO AN AS FOUND MOVAT SIGNATURE ON A VALVE THAT WE KNOW WE WILL REPACK OR REBUILD. THIS INFORMATION MAY BE GREAT FOR A DATA BASE, BUT IT COSTS SET UP TIME, HOLDS THE SYSTEM OUT FROM DOING WORK, AND COSTS POTENTIALLY UN-NECESSARY EXPOSURE. THIS IS NO MINOR TASK, YOU MAY NEED TO SCHEDULE IT FOR A 1993 EVALUATION. HAVE A GOOD DAY, BOB.

SAFETY - COST - PRODUCTION - PROFESSIONALISM

From: SPENICK --BANYAN   Date and time   10/06/92 12:23:00

From: Stephen G. Penick
To: SGUTHRIE--APSVMB60 Guthrie, Stephen C.
    SPENICK --BANYAN   Penick, Stephen G.

Subject: ISE CUSTOMER INPUT
Comments by: Stephen G. Penick@NoAnnex2@NoAnnex2
Forwarded to: Stephen C. Guthrie@NoAnnex2@NoAnnex2
Comments:

For your info.

--------------------------- |Original Message| ---------------------------

To: SPENICK --BANYAN   PENICK, STEPHEN G.

From: R. Schaller
Subject: ISE CUSTOMER INPUT

very valuable comments. They reflect the direction we're trying to go, with more visibility in plant and more issues with true safety significance presented in a well founded technical position — we're getting good management support & involvement, which we appreciate — Steve 10/22

STEVE,

IN ANSWER TO YOUR RECENT MEMO I PROVIDE THE FOLLOWING INPUT FROM U-I.

1. IN GENERAL ISE IS MEETING OUR EXPECTATIONS. HOWEVER, IT WOULD BE VALUABLE TO US IF YOUR GROUPS SPENT MORE TIME IN ROUTINE OBSERVATION AND IMMEDIATE FEEDBACK SUCH AS ROUTINE MONITOR WATCHES IN THE CONTROL ROOM OBSERVING OPERABILITY CALLS, ST EVALUATIONS, WORK CONTROL ON SHIFT, ETC.

2. SOME GOOD ITEMS TO PROVIDE FEEDBACK ON ARE: INTERORGANIZATION COMMUNICATIONS, DECISION PROCESS ON SCHEDULING HIGH RISK WORK, KNOWLEDGE OF WORKERS ON MATTERS OF MANAGEMENT INTEREST AND OTHER TOPICS PROVIDED BY THE PLANT MANAGER.

3. THE MONTHLY REPORTS ARE NOT SUCCINCT. WE FREQUENTLY HAVE TO WADE THROUGH A LOT TO GET TO THE REAL MEAT OF THE REPORT. THE SUMMARY HELPS, BUT THERE IS A LOT OF ROOM FOR IMPROVEMENT.

4. THE REPORT FORMAT IS ADEQUATE IF THE CONCERN IN NUMBER 3 ABOVE IS ADDRESSED.

5. REPORT DISTRIBUTION IS FINE.

6. INTERFACES ARE NOT OPTIMAL. TRY COMING TO DAILY STATUS MEETINGS A FEW TIMES A WEEK OR ATTENDING UNIT STAFF MEETINGS ON THURSDAY AFTERNOON ABOUT ONCE A MONTH TO OPEN UP MORE COMMUNICATION. I THINK BILL IDE'S PRACTICE OF A MONTHLY MANAGEMENT MEETING IS HELPFUL.

I HOPE THESE COMMENTS ARE CONSTRUCTIVE AND HELP YOU. I'D BE HAPPY TO MEET WITH YOU AND ELABORATE ON THIS IF NEEDED.

cc: Karen
Steve P.
Back to me

From: Z20004 --APSVMB60 Date and time 10/14/92 19:01:21
To: Z53314 --APSVMB60 IDE, WILLIAM E.
cc: SPENICK --BANYAN PENICK, STEPHEN G. Z99652 --APSVMB60 GUTHRIE, STEPHEN C
RPRABHAK--BANYAN PRABHAKAR, RAM N. Z78795 --APSVMB60 RIEDEL, FREDRICK W
Z38847 --APSVMB60 GOUGE, RICHARD E. Z32196 --APSVMB60 DENNIS, JOHN W.

From: R. Schaller
Subject: ISE CONCERN REGARDING VALVE LINEUP ST'S

Hold for STCU

BILL,

YOU ASKED ME TO SUMMARIZE HOW THE ISSUE OF ST ADEQUACY RAISED IN ISE ASSESSMENT #92-23 WAS ADDRESSED. AS YOU KNOW THERE WERE TWO CONCERNS:

1. THERE ARE A NUMBER OF ESSENTIAL COOLING WATER VALVES WHOSE POSITIONS ARE NOT CHECKED MONTHLY AND ARE NOT LOCKED OR OTHERWISE SEALED. WHY IS IT PROPER TO EXCLUDE THESE VALVES FROM THE MONTHLY VALVE LINEUP ST?

2. WHY ARE THE NC/EW CROSS TIE VALVES TESTED ON THE 18 MONTH ST OF AUTO ACTUATED VALVES, BUT IT NOT CHECKED ON THE MONTHLY LINEUP?

THESE CONCERNS WERE DOCUMENTED ON CRDR 9-2-0472 WHICH WAS RESOLVED AND CLOSED OCTOBER 1 AFTER ISE REVIEW.

THE CRDR RESPONSE LOOKED AT TWO FACETS: WHAT IS LEGALLY REQUIRED BY THE TECH SPECS, AND WHAT MEASURES SHOULD WE PRUDENTLY REQUIRE TO ENSURE EW IS AVAILABLE TO COOL SAFETY EQUIPMENT.

THE LICENSING DEPARTMENT REVIEWED THE STANDARD TECH SPECS (NUREG 0212), PVNGS TECH SPECS AND THE PROOF AND REVIEW COPY OF NEW STANDARD TECH SPECS (NUREG 1432) BEFORE CONCLUDING THAT THE CURRENT ST LINEUP CHECK SATISFIES THE MINIMUM REQUIREMENT OF CHECKING VALVES WHICH PROVIDE AN EW COOLING FLOWPATH TO SAFETY RELATED EQUIPMENT. THAT ENSURED WE LEGALLY MEET THE PVNGS TECH SPECS.

NEXT OPS STANDARDS LOOKED AT THE FUNCTION OF THE VALVES CALLED OUT BY ISE AND DETERMINED WHETHER MISPOSITIONING OF THESE VALVES COULD REASONABLY GO UNDETECTED AND IMPAIR THE ABILITY OF EW TO COOL SAFETY LOADS. IN EACH SCENARIO THEY DETERMINED THAT THE VALVE DID NOT DIRECTLY INTERRUPT THE FLOWPATH TO ANY SAFETY RELATED EQUIPMENT, AND EITHER HAD NO IMPACT ON THE SAFETY FUNCTION OF EW OR WOULD RESULT IN A MONITORED OUT OF SPECIFICATION READING (E.G. HIGH OR LOW EXPANSION TANK LEVEL) BEFORE COOLING ABILITY WAS IMPACTED. SINCE THIS WAS THE CASE THE DETERMINATION WAS MADE THAT THE CURRENT ST'S ARE ADEQUATE BOTH FROM THE STANDPOINT OF MEETING LEGAL REQUIREMENTS AND IN MEETING THE PRACTICAL INTENT OF THE SPECIFICATION.

THE QUESTION OF WHETHER THE NC/EW CROSS TIE VALVES SHOULD BE MONITORED MONTHL IS ADDRESSED AS FOLLOWS. T.S. 4.7.3.A ONLY REQUIRES MONTHLY TESTING OF VALVE IN THE COOLING FLOWPATH TO SAFETY RELATED EQUIPMENT. THE X-TIES ARE NOT IN T SAFETY GRADE FLOWPATH TO COOLING ANY SAFETY RELATED EQUIPMENT (THEY PROVIDE A MEANS OF BACKING UP EW). T.S.. 4.7.3.B REQUIRES THAT VALVES WHICH SERVICE SAFETY EQUIPMENT AND RECEIVE AUTOMATIC SIGNALS BE TESTED EVERY 18 MONTHS TO ENSURE THEY RESPOND TO THE SIGNALS. EVEN THOUGH THE CROSS TIE VALVES DO NOT SERVICE SAFETY RELATED EQUIPMENT THEY DO RECEIVE A SIAS CLOSING SIGNAL WHICH WOULD SPLIT OUT EW FROM NC IN AN EMERGENCY, AND STANDARDS CONSIDERED IT PRUDENT TO CHECK THIS FEATURE AS PART OF THE INTEGRATED RESPONSE TO A SIAS SIGNAL EVERY 18 MONTHS.

THESE RESOLUTIONS WERE REACHED AFTER SEVERAL MEETINGS WITH ISE, OPS AND OPS STANDARDS. MY INVOLVEMENT IN THIS AROSE FROM MY CONCERN WHEN READING THE REPORT, AND I REQUESTED THAT ISE DISCUSS THE ISSUES WITH THE UNIT OPS MGRS.

THROUGHOUT THE RESOLUTION I FOUND ISE TO BE SENSITIVE TO ALL THE ISSUES AND IMPACTS. STEVE PENICK DEVOTED A LOT OF HIS TIME TO HELPING US RESOLVE THIS SUCCESSFULLY. THESE WERE GOOD QUESTIONS TO ASK!

IF YOU NEED MORE INFORMATION PLEASE LET ME KNOW.

Ran/Steve → the acid-test of your value to the organization —

from the desk of

STEVE GUTHRIE

DATE: Ron/Steve

TO:

Good report —

not enough distribution —

Would Bob Adey care about

mid loop, entering an outage —

ISE DOCUMENT EVALUATION COMMENTS

DOCUMENT #: [illegible] ASSIGNED TO: [illegible]

DUE DATE: [illegible] LOG #: 727005

EVALUATION: See Attached evaluation

RECOMMENDATION(S): Include in planned ISE shutdown Safety Topical Report for IR2. PVNGS is already addressing the issues brought up by AIT + Prairie Island

DISTRIBUTION: S. Fenick
R. Prabhakar (w/s IR report)
S. Guthrie (w/o IR report)

File X N/A ____ Assessment ____

Evaluator: [illegible] Date: [illegible]/92

NRC INSPECTION REPORT (IR) 50-306/92005 AUGMENTED INSPECTION TEAM (AIT) INSPECTION OF PRAIRIE ISLAND NUCLEAR GENERATING STATION UNIT 2 LOSS OF DECAY HEAT REMOVAL (DHR) ON 2/20/92

EVALUATION:

The event was previously reviewed by ISE under NRC IN 92-16, Supplement 1 (ISE Document Evaluation Log #603004).

Prairie Island overdrained the Reactor Coolant System (RCS) while attempting to go to mid-loop operations, resulting in loss of DHR. The NRC sent an AIT to investigate the event and the AIT felt the following factors directly contributed to the cause of the event:

1. The design of the electronic level measurement instruments was incompatible with the nitrogen pressure specified in the draindown procedure. The instruments were essentially unavailable during the entire draining process.

2. The draindown procedure did not adequately describe the required processes to achieve a reduced inventory condition.

3. The training and experience of the operators and support engineering were insufficent to perform the assigned tasks.

4. The operators and senior operators did not exhibit a questioning attitude with regards to safety. With two out of three channels of instrumentation inoperable and concerns over the behavior of the plant, the operators continued draining the reactor coolant system.

6. Management attention was inadequate in the areas of training, human factors, procedure and design reviews, and operator supervision.

It is of interest to note that they were entering mid-loop two days after shutdown (PVNGS was previously analyzed for 5 days and is now analyzed for 1 day).

PVNGS does not use an nitrogen overpressure on the RCS anymore. The tygon tube, if used, is a backup to the newly installed reactor vessel water level system at PVNGS. PVNGS had an event involving the new water level instruments being inaccurrate due to inadequate venting by the technician, resulting in vortexing of the shutdown cooling (SDC) pumps. Procedures were revised to more specifically describe the venting process. PVNGS has draindown and abnormal operating procedures in place (previously reviewed by ISE in FE 91-29). Note that ISE did find the RCS draindown procedure to be complicated and made several recommendations for procedure changes which are partially incorporated at this time. As PVNGS is not going to perform mid-loop operations with fuel in the core, training has not been performed. A lesson plan is available for STA training. NUMARC 91-06, "Guidelines for Industry Actions to Assess

EVALUATION (CONTINUED):

Shutdown Management," is being incorporated into the License Operator Initial Training by June 30, 1993, and will be part of the first quarter 1993 Industry Events for non-licensed operators. Heightened operator and management attention during off-normal events was addressed in INPO SOER 91-01, which was evaluated by ISE in FE 92-01. PVNGS management has also increased supervisory presence in the field for Operations and Maintenance (see meeting notes for NRC and APS management meeting of 5/26/92). The findings of the Prairie Island AIT should not be a problem at PVNGS, given completion of existing commitments.

CC: ~~Simpson~~ ~~Guthrie~~

Docket No. 50-306

Northern States Power Company
ATTN: Mr. L. R. Eliason
Vice President, Nuclear Generation
414 Nicollet Mall
Minneapolis, MN 55401

CC: Steve Renick — Pls look into this as a potential assessment area

Fascinating report! Appropriate personnel should read & heed!!

3/29/92

Dear Mr. Eliason:

SUBJECT: NRC INSPECTION REPORT 50-306/92005

This refers to the special inspection conducted by the Nuclear Regulatory Commission Augmented Inspection Team (AIT) at your Prairie Island Nuclear Generating Plant during the period from February 21 through 25, 1992, concerning an interruption in decay heat removal during reduced inventory operations at Unit 2 which occurred on February 20, 1992. At the conclusion of the inspection, the findings were summarized at a public meeting attended by those members of your staff identified in the enclosed inspection report.

The enclosed copy of the AIT report identifies the areas examined during this inspection. Within these areas, the inspection consisted of selective examinations of plant hardware, procedures and other records, interviews with personnel, and observation of activities in progress.

The AIT concluded that management had made a number of changes in the process for establishing stable reduced-inventory conditions in the reactor cooling system. Although intended as improvements, these changes were not all adequately evaluated, either individually or in the aggregate. As a consequence, a combination of factors, including inadequate supervision, level instrument design limitations, reduced engineering support, procedure ambiguities, and inadequate training led to a condition where the personnel who were draining water from the system believed they knew the current water level when, in fact, they did not. By proceeding despite questions about instrument and system behavior, operators did not exhibit an aggressive, questioning safety attitude. Water level went below that necessary for continued operation of the in-service cooling pump, making it necessary to shut off the pump and interrupt operation of the residual heat removal system.

A review of the inspection findings is continuing to determine whether the described activities violated NRC requirements. You will be advised by separate correspondence of the results of our review of this matter.

In accordance with Section 2.790 of the NRC's "Rules of Practice," a copy of this letter and the enclosure will be placed in the NRC Public Document Room.

Should you have any questions concerning this letter, please contact us.

A. Bert Davis,
Regional Administrator

Enclosure:
NRC Inspection Report
50-306/92005

cc w/enclosure:
E. L. Watzl, Site Manager,
Prairie Island Site
M. Sellman, Plant Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspector, RIII Monticello
John W. Ferman, Ph.D.,
Nuclear Engineer, MPCA
State Liaison Officer, State
of Minnesota
Prairie Island, LPM, NRR
Robert M. Thompson, Administrator
Wisconsin Division of Emergency
Government
J. C. Partlow, NRR
C. E. Rossi, NRR
G. Holahan, NRR
W. D. Lanning, NRR
J. Zwolinski, NRR
E. Jordan, AEOD
G. Grant, EDO