UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

November 3, 2003

Greg R. Overbeck, Senior Vice
President, Nuclear
Arizona Public Service Company
P. O. Box 52034
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SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC SPECIAL INSPECTION REPORT 05000528/2003011, 05000529/2003011, AND 05000530/2003011

Dear Mr. Overbeck:

On September 19, 2003, the US Nuclear Regulatory Commission (NRC) completed a special inspection at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility. The enclosed report documents the inspection findings, which were discussed on September 19, 2003, with Mr. David Mauldin and other members of your staff.

The inspection examined the response of all three units to the grid disturbance which occurred on July 28, 2003, the consequent Unit 3 reactor trip, and subsequent equipment problems. The inspection focused on the events leading up to the reactor trip, subsequent plant response, and equipment operation as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records and interviewed personnel.

On the basis of the results of this inspection, no findings of significance were identified.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Mark A. Satorius, Deputy Director
Division of Reactor Projects

Dockets: 50-528
50-529
50-530
Licenses: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report 05000528/2003011, 05000529/2003011, and 05000530/2003011
w/Attachments: Supplemental Information
Charter for the NRC Special Inspection Team at Palo Verde Nuclear

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RITS Coordinator **(NBH)**
PV Site Secretary **(vacant)**
ANO Site Secretary **(VLH)**

ADAMS: √ Yes ☐ No Initials: __LJS__ **DMB (IE35)**
√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

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RIV:RI:DRP/D	RI:DRS/EMB	SRI:DRP/D	C:DRP/D
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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528, 50-529, 50-530
Licenses:	NPF-41, NPF-51, NPF-74
Report No:	05000528/2003011, 05000529/2003011, and 05000530/2003011
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Tonopah, Arizona
Dates:	September 15-19, 2003
Inspectors:	N. Salgado, Senior Resident Inspector, Project Branch D G. Warnick, Resident Inspector, Project Branch D J. Taylor, Reactor Inspector, Engineering and Maintenance Branch
Approved By:	Mark A. Satorius, Deputy Director Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000529/2003011, 05000528/2003011; 05000530/2003011; 9/15/03 - 9/19/03; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Special Inspection Report.

The report covered a 1-week special inspection by one senior resident inspector, one resident inspector, and one regional engineering inspector, who assessed the licensee and reactor plant response to an automatic reactor trip resulting from a three-phase ground on the offsite power grid. No findings of significance were identified. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. <u>NRC-Identified and Self-Revealing Findings</u>

No findings of significance were identified.

REPORT DETAILS

1. SPECIAL INSPECTION ACTIVITIES

The NRC conducted this special inspection to better understand the response of all three units to the grid disturbance, consequent Unit 3 reactor trip, and subsequent equipment problems.

The special inspection team evaluated the potential safety implications related to the cause of the reactor trip and the subsequent loss of some nonsafety-related equipment. The team used NRC Inspection Procedure 93812, "Special Inspection," to conduct the inspection. The team reviewed procedures, operator logs, corrective action documents, a posttrip review report, and design and maintenance records for equipment of concern. The team interviewed key station personnel regarding the reactor trip event and restoration of systems. The team performed a walkdown of the Unit 3 cabinets that contained the subsynchronous oscillation (SSO) relays and the undervoltage (UV) relays. Attachment 2 is the team charter which describes the inspection scope in greater detail.

2. DESCRIPTION OF EVENT AND CHRONOLOGY

2.1 System Description

Palo Verde Nuclear Generating Station (PVNGS) Electrical Distribution System

The PVNGS 525 kilovolt (kV) switchyard is the receiving location for offsite power from the Westwing 1 and 2, Rudd, Hassayampa 1, 2, and 3, and Devers lines, which are part of the offsite electrical grid system. The PVNGS switchyard also serves as the transmission system for electrical power generated by the site's main generators, which exits the switchyard through the same lines when the plant is operating. The PVNGS switchyard consists of two buses, the 525 kV east bus and the 525 kV west bus. All breakers in the switchyard are electrically isolable by two disconnect switches on either side of the breakers. Power to PVNGS Class 1E electrical equipment is normally supplied from the PVNGS switchyard through startup Transformers X01, X02, and X03. This electrical equipment includes the engineered safety features (ESFs) equipment powered through electrical Buses PBA-S03 and PBB-S04 for each unit. If offsite power to these ESF buses is degraded or isolated, emergency diesel generators will start automatically and provide power to the ESF electrical equipment. Additionally, power is also available to the ESF buses from station blackout gas turbine generators.

The SSO relays protect the main turbine generator from subsynchronous resonance phenomena that are associated with grid distribution resonances from long transmission lines and widely separated generation sources. The subsynchronous resonance phenomena can result in high torsion on the turbine generator shaft. The setpoints for the relays are staggered between the units, with Unit 3 being the most sensitive and Unit 1 being the least sensitive. The setpoint staggering allows for tripping of a single unit, which should provide enough detuning of the grid to avoid having the other units trip.

2.2 Event Summary

On July 28, 2003, the Unit 3 reactor automatically tripped due to a low departure from nucleate boiling ratio signal caused by loss of reactor coolant pumps, which were powered from the nonsafety 13.8 kV buses that de-energized. The loss of power to these nonsafety buses was caused by a main turbine generator trip and failure to complete a fast bus transfer (FBT) from the normal auxiliary transformer supply to the alternate offsite startup transformer supply. The normal auxiliary transfer supply was unavailable because the main turbine generator tripped due to operation of SSO relays. The trip was caused by a grid disturbance. The FBT did not occur because the UV relay detected that voltage had not recovered from the voltage transient. This is a design feature which prevents a fast bust transfer to a dead bus or otherwise damaged power supply. The cause of the grid disturbance was a three-phase bolted ground on the offsite Hassayampa 1 525 kV line, which is approximately 1.5 miles from PVNGS. The ground was caused by a maintenance error in the Hassayampa switchyard.

All three units sensed the grid disturbance. Unit 3 tripped, as designed, due to the staggered setpoints on the SSO relays. The transient's duration was approximately 50-67 milliseconds, with the grid voltage being recovered in approximately 2 additional seconds. The 4.16 kV safety buses experienced a voltage drop, but the transient was so short that the bus UV relays did not de-energize the buses and emergency diesel generators did not start.

The grid disturbance also caused a loss of power and lock-out of instrument air compressors and normal chilled water chillers on Units 1, 2, and 3. Additionally, the licensee discovered that the third-stage seal on Reactor Coolant Pump (RCP) 2A had failed following isolation of controlled bleed-off.

2.3 Preliminary Risk Significance of Event

This significant operational event was evaluated for risk because: it potentially involved operations that did not meet the design basis as described in General Design Criteria 17; there were potential generic implications associated with the RCP seal failure; there were potential unexpected system interactions in the form of loss of power and equipment lock-outs on all three units and anomalous turbine trip annunciation on Unit 1; and there may be design errors associated with the transmission system protective relaying.

The Unit 3 turbine trip/reactor trip that resulted from the grid disturbance on July 28, 2003, was an event of moderate risk significance. At the request of the NRC, the licensee evaluated the risk associated with this event and estimated the conditional core damage probability as 1.5E-5. As such, in accordance with Management Directive 8.3, "NRC Incident Investigation Program," either a special inspection or an augmented inspection was warranted. The NRC staff reviewed the characteristics for considering the formation of an incident investigation team (IIT) or an augmented inspection team (AIT) found in Management Directive 8.3. The NRC concluded that this event did not meet the criteria for consideration of an IIT or AIT response. The NRC determined that a special inspection in accordance with Inspection Procedure 93812 was appropriate. During the inspection, the team did not identify any new information that would affect the risk analysis. This activity satisfied Special Inspection Team Charter Scope Item 9.

2.4 Sequence of Events

Consistent with the direction provided in the team's charter, the team developed a detailed sequence of events leading up to the grid disturbance and following the Unit 3 automatic reactor trip. The timeline included events applicable to Unit 3 and actions before, during, and following the reactor trip. The timeline was generated from operator logs, written records, alarm printouts, a posttrip report, and interviews with the licensee's staff. This activity satisfied Special Inspection Team Charter Scope Item 1.

July 27, 2003

0655 Protective relays tripped breakers open to de-energize the "Hassayampa to Arlington Valley 500 kV line."

July 28, 2003

0325 Protective relays tripped breakers open to de-energize the "Hassayampa to Arlington Valley 500 kV line." Contaminated insulators on a structure inside Arlington Valley's 500 kV switchyard were determined to be the cause.

(morning) Salt River Project (SRP) removed the "Hassayampa to Arlington Valley 500 kV line" from service to repair and clean the contaminated insulators.

1835 Maintenance crew for the "Hassayampa to Arlington Valley 500 kV line" released their clearance to SRP transmission dispatch center.

1835-1854 SRP instructed SRP troubleman to remove tags and open grounding Switch HAA 937G. Troubleman reported back the tag is removed and the switch is open.

SRP instructed troubleman to verify open Breakers HAA 935 and 938 and then remove tags and close 500 kV Disconnects 934, 936, 937, and 938. The troubleman reported back that these steps had been completed.

SRP reviewed status of breakers and switches with the troubleman.

1854 SRP closed 500 kV Breaker HAA 938. The 500 kV grounding Switch HAA 937G had remained in the close position.

1854.33	PVNGS Unit 3 main turbine tripped on an SSO relay lockout trip.
1854.34	PVNGS Unit 3 reactor tripped on low departure from nucleate boiling ratio due a loss of forced circulation. Nonclass 13.8 kV Buses NANS01 and NANS02 did not FBT to offsite power, causing a loss of power to all four RCPs.
1855	Unit 3 operators performed standard posttrip actions.
1855	Crew initiated boration due to not having confirmation for two of three indicators for control element assemblies (CEAs) 9 and 11 being fully inserted.
1855-1900	Control bleed-off isolated to RCPs, as directed by procedures due to loss of nuclear cooling water.
1905	CEAs 9 and 11 rod bottom lights and digital displays match control element assembly calculator display screen (per operator logs).
1908	Control room supervisor entered Procedure 40OP-9EO07, "Loss of Offsite Power/Loss of Forced Circulation."
1912	Main steam isolation signal manually initiated as directed by procedures due to loss of condenser cooling.
1948	Crew began controlled reactor coolant system cooldown per Procedure 40OP-9EO07.
1953	Crew restored power to 13.8 kV Buses NANS01, NANS02, NBNS01, and NBNS02.
1959	Instrument Air Compressor A restored to service.
2012	Normal Chillers B and C returned to service
2014	Plant Cooling Pump A restored.
2020	Crew aligned Train B essential cooling water to spent fuel pool cooling.
2029	Turbine Cooling Water Pump A restored.
2039	Nuclear Cooling Water Pump B restored.
2051	Letdown restored.

2122 Containment sump excess leakage alarm. Effluent technician noticed raised reading on containment building atmosphere radiation Monitor RU-1 Channel 4.

2242 NRC notification completed.

July 29, 2003

0043 RCP 1A started restoring forced circulation. Crew started heatup back to normal operating temperature and normal operating pressure.

0102 RCP 1B started.

0257 Crew reset main steam isolation signal.

0300 Containment entry walkdown identified and quantified leakage of 1.7 gpm from RCP 2A seal.

0325 Crew exited Procedure 40EP-9EO07 and entered Procedure 40OP-9ZZ10, "Mode 3 to 5 Operations."

1500 Crew commenced cooldown to Mode 5 to repair RCP 2A seal.

July 30, 2003

1135 Mode 5 is entered.

2.5 Response and Availability of Risk Significant Mitigation Equipment

a. Inspection Scope

The inspectors obtained the dominant cutsets from the senior reactor analyst and evaluated the response and availability of risk significant mitigation equipment. The inspectors also held discussions with the licensee's probabilistic risk assessment expert about the dominant cutsets. The inspectors evaluated the response and availability of the auxiliary feedwater system and the adequacy of the protective relay schemes associated with the nonclass switchgear that de-energized during the trip. This activity satisfied Special Inspection Team Charter Scope Item 3.

b. Findings

No findings of significance were identified.

The team discussed the dominant cutsets with the senior reactor analyst. The probabilistic risk assessment model indicated that the auxiliary feedwater system was the system of highest importance to this event. The team found that this system was fully available during the event. The protective relaying associated with the nonclass switchgear that de-energized during the trip met appropriate design criteria and responded appropriately. See Section 3.2 for additional information.

3. OVERALL OPERATOR AND PLANT RESPONSE

3.1 Human Performance

a. Inspection Scope

The team reviewed the response by operation’s personnel to the turbine and reactor trip and loss of nonvital electrical buses. Specifically, the team evaluated human factor and procedural issues related to the measures necessary to restore power and return equipment to service through review of operator personnel statements and completed plant procedures. The team also verified the adequacy of available staff and procedures. This activity satisfied Special Inspection Team Charter Scope Item 2.

b. Findings

No findings of significance were identified.

The team determined that operators implemented emergency operating procedures in accordance with Procedure 40DP-9AP16, "Emergency Operating Procedure Users Guide," Revision 3. However, during the recovery of plant equipment following restoration of nonvital buses, a procedural inadequacy was identified by the operations crew. Optimal Recovery Procedure 40EP-9EO07, "Loss of Offsite Power/Loss of Forced Circulation," Revision 8, step 50, prompted operators to restore the normal nonvital source of cooling water to the spent fuel pool using Procedure 40EP-9EO10, "Standard Appendices," Revision 24, Appendix 77. The operators could not return the essential cooling water system to the required lineup due to the inadequacy of Procedure 40EP-9EO10. The operators were able to properly restore the system to the required lineup by implementing applicable portions of Procedure 40OP-9EW02, "Essential Cooling Water System Train B," Revision 1. The failure to have adequate procedures as required by 10 CFR Part 50, Appendix B, Criterion V, constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV.A.5.a of the NRC's Enforcement Policy. This issue was incorporated into condition report/disposition request (CRDR) 2623273 for resolution.

The team confirmed that the requirements of Technical Specification 5.2.2, "Unit Staff," were satisfied. Additionally, the team observed that site manning was adequate to respond to the results of the grid disturbance for all three units.

3.2 Unit 3 Protective Relay Schemes

a. Inspection Scope

The team reviewed the causes for the grid disturbance and the Unit 3 turbine and reactor trip. The team interviewed personnel and reviewed condition reports, switchyard diagrams, plant electrical schematics, and relay setting calculations and calibration sheets in this effort. This activity satisfied Special Inspection Team Charter Scope Items 3, 5, and 8.

b. Findings

No findings of significance were identified.

The team determined that the offsite power system, the actuation of the SSO relays, and the nonsafety 13.8 kV busses' FBT scheme performed as designed and complied with General Design Criteria 17. The staggered setpoints of the SSO relays appeared adequate for preferentially tripping the units. However, the licensee will re-evaluate the SSO relay schemes via CRDR 2623273 Action Item 2633041 to determine if improvements can be made consistent with historical risk experienced to date.

Historically, the Unit 3 main turbine generator experienced an SSO relay trip on February 25, 1996, during a grid transient caused by a Unit 1 main turbine generator trip. The Unit 1 main turbine generator tripped because of a lightning strike to the Phase C transformer high voltage bushing. After this event, the SSO relays were desensitized to reduce the risk of undesired trips versus historical low probability risk of an actual SSO condition. Review of this, and other precursor events, determined that the licensee had performed a thorough analysis of the relays and adequately performed corrective action based on apparent risks at the time.

The FBT did not occur because the undervoltage relay used to determine the acceptability of the target power source detected inadequate voltage. This is a design feature which prevents a fast bust transfer to a dead bus or otherwise damaged power supply. Therefore, the FBT worked as designed when the fast transfer did not occur. The licensee has initiated an action via CRDR 2623273, Action Item 2633046, to evaluate the design and determine if any improvements or modifications to this scheme are required.

3.3 Response of Affected Equipment

a. Inspection Scope

The team evaluated the response of various equipment in all the units that failed to respond as expected, including the Unit 3 RCP 2A seal package and the Unit 1 turbine trip annunciation. This activity satisfied Special Inspection Team Charter Scope Item 4.

b. Findings

No findings of significance were identified.

The RCP 2A seal package leakage was due to failure of a third stage 'O' ring. An unresolved item (URI) was opened to track the determination of the root cause of the failure. This URI is further described in Section 4.2.

Turbine trip annunciation received in Unit 1 was not a valid trip. The annunciation was apparently caused by the electrical transient and the alarm window only momentarily flashed and cleared, without an actual trip being experienced. The licensee determined that this response was not unique, had occurred a few times in the past, and was of no consequence.

All operating normal chillers for Units 1, 2, and 3 tripped when the grid disturbance occurred. The team evaluated normal chiller response by reviewing CRDR 2623273, Attachment 12. Through this review, the team concluded that the normal chillers responded per circuit design. The local control panels for the normal chillers utilize ac powered relays that momentarily dropped out and shutdown the normal chillers. There is no auto-restart feature, thus operator action was required to reset the normal chillers for restart. Containment temperatures increased for all units; however, the temperature did not exceed Technical Specification requirements.

All operating instrument air compressors for Units 1, 2, and 3 tripped when the grid disturbance occurred. There was no impact on plant operations as the backup nitrogen system was available. The team evaluated instrument air compressors' response by reviewing CRDR 2623273, Attachment 11. Through this review, the team concluded that the controls acted as designed. Operators reset the units and an instrument air compressor was started in each unit.

The Unit 1 main turbine lube oil conditioners and reactor makeup pump also tripped because of low voltage during the voltage transient. They were reset and restarted.

RCP 2B lift oil pump tripped on thermal overloads. The pump was subsequently run several times and was tested electrically with no problems identified.

Unit 3 CEAs 9 and 11 rod bottom lights were slow to illuminate. Independent of the rod bottom lights, operators verified all rods had fully inserted on the control element assembly calculator display screen. The operators also confirmed that the lower electrical limits illuminated following the trip. Emergency boration was initiated per standard posttrip actions. Licensee followup determined that CEAs 9 and 11 fully inserted with the reactor trip. Review of plant data determined that rod bottom lights for CEAs 9 and 11 came on at 9 and 14 minutes, respectively. CRDR 2623273, Attachment 14, addressed the issue. Work Mechanism 2624363 was written to document the deficiency and to perform troubleshooting. The indication problem has been determined to be in the system's isolation relays' contacts.

Abnormal condition on Unit 3 Load Center LC-02 occurred. Air removal Pump A, turbine control oil Pump B, service/breathing air compressor, and instrument Air Compressor B all had "86 lockouts." A ground fault on the air removal pump motor apparently tripped nearby ground fault relays on other loads and operated lockouts. The bus was inspected, reset, and returned to service.

A ground developed on Load Center LC-17, which supplies power for Unit 3 containment lighting. Electricians reset the ground.

A leak developed on the Unit 3 isolation valve for the plant cooling water Pump B discharge pressure gauge. The leak was isolated and repaired per Work Mechanism 2623440.

4. CORRECTIVE ACTIONS

4.1 Root Cause Evaluation

a. Inspection Scope

The team reviewed the licensee's significant investigation report CRDR 2623273, "Unit 3 Turbine and Reactor Trip on Switching Error at the Hassayampa Switchyard," Revision 1, for independence, completeness, and accuracy. The team interviewed the lead investigator, and other members of the licensee as part of this inspection effort. This activity satisfied Special Inspection Team Charter Scope Item 6.

b. Findings

No findings of significance were identified.

CRDR 2623273 evaluation determined that the direct cause of the Unit 3 main turbine trip was a human performance error at the Hassayampa switchyard. The direct cause of the reactor trip was a loss of all RCPs when 13.8 kV Buses NANS01 and NANS02 did not autotransfer to the alternate offsite power source. The transfer did not occur due to voltage requirement not being met within the required time frame. The licensee performed a thorough historical review of past grid disturbances.

Revision 1 of the report identified the need for 15 corrective actions associated with this event. A schedule for the remaining corrective actions had been developed with planned completion date of January 27, 2004.

The licensee's investigation report was objective and provided a comprehensive self-assessment of its performance.

4.2 Extent of Conditions

a. Inspection Scope

The team evaluated corrective action documents, maintenance work orders, operator logs, and personnel statements and conducted interviews to assess the extent of condition review performed by the licensee. The team evaluated both safety- and nonsafety-related equipment failures and degradations to consider operational impact, potential generic implications, and corrective actions taken. This activity satisfied Special Inspection Team Charter Scope Item 7.

b. Findings

No findings of significance were identified.

The team concluded that adequate consideration was given to evaluating the extent of condition for failure and degradation of equipment following the grid disturbance. Equipment performed as designed in response to the electrical transient, with respect to breaker trip features for equipment protection, with no adverse impact to plant safety. Equipment issues identified during the event were appropriately entered into the corrective action program for evaluation and resolution. Additionally, no generic implications were identified.

Operators isolated controlled bleed-off to the RCPs per Procedure 40AO-9ZZ04, "Reactor Coolant Pump Emergencies," Revision 16, due to the loss of nuclear cooling water. Subsequent to controlled bleed-off isolation, operators identified reactor coolant system leakage of approximately 1.7 gallons per minute due to a third stage seal failure on RCP 2A. The licensee established plant conditions to terminate the leak and replace the degraded seal package. The equipment issue has been entered into the corrective action program as CRDR 2627059. A URI is initiated pending review of the root cause evaluation for the RCP 2A seal failure and is identified as URI 05000530/2003011-01, "Reactor Coolant Pump 2A Seal Failure Root Cause Evaluation."

4.3 Posttrip Restart Review

a. Inspection Scope

The team evaluated the Unit 3 posttrip review to assess independence, completeness, and accuracy. Additionally, the team reviewed other corrective action documents, including corrective actions taken prior to restart. The team also attended management review team and plant review board meetings conducted following the event and prior to restart. This activity satisfied Special Inspection Team Charter Scope Item 6.

b. Findings

No findings of significance were identified.

The team determined that a thorough posttrip review was performed by the licensee. The management review team and plant review board maintained an adequate questioning attitude and evaluated event information and associated corrective actions with appropriate independence. The team concluded that the information assembled in the posttrip review was accurate with respect to plant and system response following the grid disturbance. However, the team identified an inconsistency associated with the feedwater control system description in the "Control System Response Evaluation" that related to actions taken by the reactor operator. The operator actions discussed were not consistent with posttrip plant conditions and, consequently, the appropriateness of the operator response was questioned by the team. It was determined that this inconsistency was inappropriately included in the evaluation and that the described operator actions did not occur. This inaccuracy was not identified by engineering during the approval of the evaluation or by the plant review board members. The licensee initiated CRDR 2635817 to evaluate and correct this issue.

5. EXIT MEETING SUMMARY

On September 19, 2003, the team presented the inspection results to Mr. David Mauldin and other members of his staff. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT 1: SUPPLEMENTAL INFORMATION

ATTACHMENT 2: CHARTER FOR THE NRC SPECIAL INSPECTION TEAM AT PALO VERDE NUCLEAR

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

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S. Bauer, Department Leader, Regulatory Affairs
D. Carnes, Department Leader, Operations
D. Fan, Department Leader, Design Engineering
A. Fluegge, Lead Investigator, Nuclear Assurance Department
F. Gower, Site Representative, El Paso Electric
R. Henry, Site Representative, Salt River Project
J. Holmes, Section Leader, Maintenance Engineering
S. Kesler, Section Leader, Nuclear Electrical Engineering
A. Kranik, Director, Emergency Services Division
H. Leake, Senior Consultant, Nuclear Electrical Engineering
D. Mauldin, Vice President, Engineering and Support
C. Seaman, Director, Nuclear Assurance and Regulatory Affairs
G. Sowers, Section Leader, Probabilistic Risk Assessment
M. Winsor, Director, Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000530/2003011-01	URI	RCP 2A Seal Failure Root Cause Evaluation (Section 4.2)

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 3.1: Human Performance

Procedure

40DP-9AP06, “Standard Post Trip Actions Technical Guidelines,” Revision 10

CRAI

2635902
2635686

Miscellaneous

Classroom Lesson Plan NLR03C020602, “C06-LOCA/LOOP,” Revision 0

Simulator Scenario NLR03S020501, “SCN - 5 New S/G & LOOP w/ Restore Offsite Power,” Revision 1

Section 3.2: Unit 3 Protective Relay Schemes

Drawings

02-E-MAB-006, R3 Generator & Transformer Primary Protection Unit Tripping
02-E-MAB-009, R4 Generator & Transformer Primary Protection Unit Tripping
02-E-MAB-037, R9 525 KV SWYD BRKRS-Cont Rm Interface
03-E-NAA-005, R4 13.8 KV Non-Class 1E Power Sys. Swgr 3E-NAN-S02
03-E-NAA-004, R5 13.8 KV Non-Class 1E Power Sys. Swgr 3E-NAN-S

Section 3.3: Response of Affected Equipment

Procedures

40DP-9AP12, “Loss of Offsite Power / Loss of Forced Circulation Technical Guideline,” Revision 9

40EP-9EO09, “Functional Recovery,” Revision 12

40ST-9ZZM1, “Operations Mode 1 Surveillance Logs,” Revision 21

40ST-9ZZM3, “Operations Mode 3 Surveillance Logs,” Revision 11

PVNGS Design Basis Manual, “Hazards Topical,” Revision 6

ANPP Design Criteria Manual, “Detailed Design Criteria,” Revision 4

ANPP Design Criteria Manual, “Detailed Design Criteria,” Revision 6

480V Non-Class 1E Power Sys Load Center 3E-NGN-L02

480V Non-Class 1E Power Sys Load Center 3E-NGN-L16

480V Non-Class 1E Power Sys Load Center 3E-NGN-L17

Work Mechanisms

2634443
2634520

Miscellaneous

Technical Specification 3.6.5, “Containment Air Temperature”

Calculation TA-13-C00-200-001, “Emergency Operating Procedures (EOP) Setpoint Document,” Revision 2

Work Orders

2421990
2623824

CRDRs (Partial Listing)

160160
2585418
2585476
2604392
2623273
2624363
2625489

Section 4.2: Extent of Conditions

Procedure

40DP-9AP06, “Standard Post Trip Actions Technical Guidelines,” Revision 10

CRDR

2627059

Section 4.3: Posttrip Review

Procedures

90DP-0IP06, “Reactor Trip Investigation,” Revision 12

CRDRs

2635817
2624427
2623273

LIST OF ACRONYMS

AIT	augmented inspection team
CRDR	condition report/disposition requests
CEA	control element assembly
ESF	engineered safety features
FBT	fast bus transfer
IIT	incident investigation team
kV	kilovolt
NRC	Nuclear Regulatory Commission
PVNGS	Palo Verde Nuclear Generating Station
RCP	reactor coolant pump
SSO	subsynchronous oscillation
SRP	Salt River Project
URI	unresolved item
UV	undervoltage

ATTACHMENT 2

CHARTER FOR THE NRC SPECIAL INSPECTION TEAM AT PALO VERDE NUCLEAR GENERATING STATION (PVNGS) - REVIEW OF LICENSEE ACTIONS RELATED TO THE JULY 28 GRID DISTURBANCE AND CONSEQUENT TRIP OF UNIT 3 (ML033080284)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

November 3, 2003

MEMORANDUM TO: Nancy L. Salgado, Senior Resident Inspector

FROM: Arthur T. Howell III, Director, Division of Reactor Projects ***/RA/***

SUBJECT: CHARTER FOR THE NRC SPECIAL INSPECTION TEAM AT PALO VERDE NUCLEAR GENERATING STATION (PVNGS) - REVIEW OF LICENSEE ACTIONS RELATED TO THE JULY 28 GRID DISTURBANCE AND CONSEQUENT TRIP OF UNIT 3

In response to our initial evaluation of impact of the July 28 grid disturbance, a Special Inspection Team is being chartered. The inspection team is being dispatched to better understand the response of all three units to the grid disturbance. You are hereby designated as the Special Inspection Team leader.

A. Basis

On July 28, 2003, Unit 3 of the PVNGS tripped due to an offsite power perturbation caused by a maintenance error in a nearby electrical switchyard. On the basis of the offsite power configuration of the facility, all three units sensed the disturbance, but only Unit 3 tripped. Unit 3 reactor coolant pumps lost power during the transient, resulting in reduced reactor coolant system flow and the automatic reactor trip due to a low departure from nucleate boiling ratio. During restoration of forced flow, the licensee discovered that the third stage seal for Reactor Coolant Pump 2A was leaking. The grid disturbance also caused a loss of power and lock-out of instrument air compressors and normal chilled water chillers on Units 1, 2, and 3.

This significant operational event was evaluated for risk because: it potentially involved operations that did not meet the design basis as described in General Design Criteria 17; there are potential generic implications associated with the seal failure; there were potential unexpected system interactions in the form of loss of power and equipment lock-outs on all three units and anomalous turbine trip annunciation on Unit 1; and there may be design errors associated with the transmission system protective relaying.

The turbine trip/reactor trip that resulted from the loss of secondary power in Unit 3 on July 28, 2003, was an event of moderate risk significance. At the request of the NRC senior reactor analyst, the licensee evaluated the risk associated with this event and estimated the conditional core damage probability (CCDP) as 1.5E-5. As such, in accordance with Management Directive 8.3, either a special inspection or an augmented inspection is warranted.

We reviewed the characteristics for considering the formation of an incident investigation team (IIT) or an augmented inspection team (AIT) found in Management Directive 8.3. Our initial review concluded that this event did not meet the criteria for consideration of an IIT or AIT response. Office of Nuclear Reactor Regulation management has agreed that an AIT is not warranted. We have determined that a special inspection in accordance with Inspection Procedure 93812 is appropriate.

B. Scope

Specifically, the team is expected to perform data gathering and fact-finding in order to address the following:

1. Develop a sequence of events related to the plant response to the July 28, 2003, grid disturbance.

2. Evaluate operator response to the trip. Specifically, evaluate human factor and procedural issues related to the measures necessary to restore power and return equipment to service, including the procedure to isolate control bleedoff when nuclear cooling water is lost to the reactor coolant pump seal packages. Confirm the adequacy of available staff and procedures.

3. Obtain the dominant cutsets from the Senior Reactor Analyst and evaluate the response and availability of risk significant mitigation equipment, including:

   a. The availability of the auxiliary feedwater system

   b. The adequacy of the protective relay schemes associated with the nonclass switchgear that deenergized during the trip

4. Evaluate the response of affected equipment. Develop a list of equipment that did not respond as designed, including:

   a. The seal package for Unit 3 Reactor Coolant Pump 2A

   b. The turbine trip annunciation on Unit 1

5. Evaluate the protective relay schemes related to the offsite power supplies to confirm compliance with General Design Criteria 17. Also review the adequacy of the protective relaying as it relates to preferentially tripping Unit 3, then Unit 2, then Unit 1 in response to grid disturbances.

6. Review the licensee’s posttrip review and root cause evaluation determination for independence, completeness, and accuracy, including the risk analysis of the event.

7. For identified failures and degradations, review the extent of the condition, potential generic implications, and the corrective actions proposed by the licensee.

8. Review precursor events, if any, to assess the acceptability of the licensee's previous corrective actions.

9. If any new information is identified that would affect the risk analysis, provide it to the Senior Reactor Analyst.

3. Team Members

Nancy Salgado, Senior Resident Inspector (Team Leader)
Greg Warnick, Resident Inspector
Joseph Taylor, Reactor Inspector

4. Guidance

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used by the inspection team.

This memorandum designates you as the Special Inspection Team leader. Your duties will be as described in Inspection Procedure 93812. The team composition will consist of yourself; Gregory Warnick, Resident Inspector, Project Branch D, Division of Reactor Projects; and Joseph Taylor, Reactor Inspector, Engineering and Maintenance Branch, Division of Reactor Safety. During performance of the Special Inspection, the designated team members are separated from normal duties and report directly to you. You will continue to report to the Chief, Project Branch D and your normal duties will be performed by Jim Melfi, Resident Inspector, Project Branch D, Division of Reactor Projects.

The team is to emphasize fact-finding in its review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

The Team will report to the site, conduct an entrance meeting, and begin inspection on or before September 15, 2003. Related information that was gathered by the resident inspectors during initial followup of the grid disturbance and consequent Unit 3 trip will also be included in this inspection report as appropriate. Tentatively, the inspection should be completed by the close of business on September 19, 2003. A formal exit meeting will be scheduled following completion of the on-site inspection. A report documenting the results of the inspection will be issued within 30 days following the exit meeting. While the team is active, you will provide periodic status briefings to Region IV management.

This Charter may be modified should the team develop significant new information that warrants review. Should you have any questions concerning this Charter, contact me at (817) 860-8248.

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cc via E-mail:
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