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

EA-

Gregg R. Overbeck, Senior Vice
President, Nuclear
Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3 - NRC AUGMENTED INSPECTION TEAM (AIT) REPORT 05000528/2004-012; 05000/204529/2004-012; 05000530/2004-012 AND PRELIMINARY FINDINGS

Dear Mr. Overbeck:

On June 18, 2004, the Nuclear Regulatory Commission (NRC) completed an Augmented Inspection at your Palo Verde Nuclear Generating Station, Units 1, 2 and 3. The enclosed repot documents the inspection findings, which were preliminarily discussed on June 18, 2004, with you and other members of your staff. A public exit was conducted with you and other members of your staff on July 12, 2004.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

Bruce S. Mallet, Regional Administrator
Region IV

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

Enclosure:

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cc w/enclosure:
Steve Olea
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Douglas K. Porter, Senior Counsel
Southern California Edison Company
Law Department, Generation Resources
P.O. Box 800
Rosemead, CA 91770

Chairman
Maricopa County Board of Supervisors
301 W. Jefferson, 10th Floor
Phoenix, AZ 85003

Aubrey V. Godwin, Director
Arizona Radiation Regulatory Agency
4814 South 40 Street
Phoenix, AZ 85040

M. Dwayne Carnes, Director
Regulatory Affairs/Nuclear Assurance
Palo Verde Nuclear Generating Station
Mail Station 7636
P.O. Box 52034
Phoenix, AZ 85072-2034

Hector R. Puente
Vice President, Power Generation
El Paso Electric Company
310 E. Palm Lane, Suite 310
Phoenix, AZ 85004

Jeffrey T. Weikert
Assistant General Counsel
El Paso Electric Company
Mail Location 167
123 W. Mills
El Paso, TX 79901

John W. Schumann
Los Angeles Department of Water & Power
Southern California Public Power Authority
P.O. Box 51111, Room 1255-C
Los Angeles, CA 90051-0100

John Taylor
Public Service Company of New Mexico

2401 Aztec NE, MS Z110
Albuquerque, NM 87107-4224

Cheryl Adams
Southern California Edison Company
5000 Pacific Coast Hwy. Bldg. DIN
San Clemente, CA 92672

Robert Henry
Salt River Project
6504 East Thomas Road
Scottsdale, AZ 85251

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
1701 North Congress Avenue
Austin, TX 78701-3326

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
Senior Resident Inspector **(GXW2)**
Branch Chief, DRP/D **(TWP)**
Senior Project Engineer, DRP/D **(JAC)**
Staff Chief, DRP/TSS **(PHH)**
RITS Coordinator **(KEG)**
Jennifer Dixon-Herrity, OEDO RIV Coordinator **(JLD)**
PV Site Secretary **(vacant)**
G. Sanborn, ACES **(GFS)**
M. Vasquez, ACES **(GMV)**
S. Lewis, OGC **(SHL)**

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ATGody/lmb	CJPaulk	TMcConnell	PAlter	TKoshy	APal	GSanborn	DDChamberlain

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528; 50-529; 50-530
Licenses:	NPF-41; NPF-51; NPF-74
Report No.:	05000528/2004-011; 05000529/2004-011; 05000530/2004-011
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	June 14 through July 12, 2004
Team Leader:	Anthony T. Gody, Chief Operations Branch
Inspectors:	P. Alter, Senior Resident Inspector, Projects Branch B Division of Reactor Projects T. Koshy, Electrical & Instrumentation and Controls Branch Office of Nuclear Reactor Regulation Amar Pal, Electrical & Instrumentation and Controls Branch Office of Nuclear Reactor Regulation T. McConnell, Resident Inspector, Projects Branch D Division of Reactor Projects C. Paulk, Senior Reactor Inspector, Engineering Branch Division of Reactor Safety
Accompanied By:	G. Skinner, Electrical Engineer, Beckman and Associates
Approved By:	Anthony T. Gody, Chief Operations Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000528/2004-012; 05000-529/2004-012; 05000-530/2004-012; June 18, 2004; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Augmented Inspection

The report covered a period of inspection by inspectors. The significance of most findings is indicated by its color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the Significance Determination Process does not apply may be green or be assigned a severity level after NRC management review. 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.

NRC-Identified and Self Revealing Findings

On June 14, 2004, at 9:41 a.m. CDT, a ground-fault occurred Phase "C" of a 230 kV transmission line in northwest Pheonix, Arizona between the "West Wing" and "Liberty" substations located approximately 47 miles from the Palo Verde Nuclear Generating Station (PVNGS). A failure in the protective relaying resulted in the ground-fault not isolating from the local grid for approximately 38 seconds. This uninterrupted fault cascaded into the protective tripping of a number of 230kV and 525kV transmission lines, a nearly concurrent trip of all three PVNGS units, and the loss of six additional generation units nearby within approximately 30 of fault initiation. This represented a total loss of nearly 5,500 MWe of local electric generation. Because of the loss-of-offsite power (LOOP), the licensee declared a Notice of Unusual Event (NOUE) for all three units at approximately 9:50 a.m. CDT. The Unit 2 Train "A" Emergency Diesel Generator (EDG) started, but failed early in the load sequence process due to a diode that had less than seventy hours of run time in the exciter rectifier circuit that short-circuited. This resulted in the Train "A" Engineering Safeguards Features (ESF or Safety) busses de-energizing which limited the availability of certain safety equipment for operators. Because of this failure, the licensee elevated the emergency declaration for Unit 2 to an Alert at 9:54 CDT.

An NRC Augmented Inspection Team (AIT) was dispatched to the site later that same day and found that the licensee's response to the event, while generally acceptable, was complicated by a number of equipment failures, procedure issues, and human performance issues with diverse apparent causes and with varying degrees of significance.

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Report Details

1.0 Introduction

1.1 Event Description

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The Unit 2 Train "A" Emergency Diesel Generator (EDG) started, but failed early in the load sequence process due to a diode that had less than seventy hours of run time in the exciter rectifier circuit that short-circuited. This resulted in the Train "A" Engineering Safeguards Features (ESF or Safety) busses de-energizing which limited the availability of certain safety equipment for operators. Because of this failure, the licensee elevated the emergency declaration for Unit 2 to an Alert at 9:54 CDT.

An NRC Augmented Inspection Team (AIT) was dispatched to the site later that same day and found that the licensee's response to the event, while generally acceptable, was complicated by a number of equipment failures, procedure issues, and human performance issues with diverse apparent causes and with varying degrees of significance. For example;

- The Technical Support Center (TSC) emergency diesel generator failed because a test switch was not returned to its' proper position following maintenance six-days prior to the event. As a result, the emergency response organization assembled in the alternate TSC. This resulted in some confusion and posed some unique challenges to the emergency response organization.
- The ability of the licensee to conduct automatic dial out for emergency responders and to develop protective action recommendations, had they been needed, appeared to have been affected by the loss of power.
- Other facility issues were identified which could have impeded emergency responders but did not during this event.
- An Atmospheric Dump Valve (ADV) on Unit 1 drifted closed due to an apparent equipment malfunction which posed a minor operational nuisance to the control room operators during the event.
- Operators did not anticipate that the Unit 1 letdown system would not automatically isolate because a temporary modification was not fully understood or translated into operating procedures. This resulted in high temperatures in that system. The high temperatures resulted in fumes being generated as paint heated up which precipitated a fire brigade response. This complicated the Unit 1 event.

- The Unit 2 Positive Displacement Charging Pump "E" was temporarily lost due to human performance errors.
- An unanticipated control interaction in the Unit 3 steam bypass control valve system resulted in a momentary opening of all Unit 3 steam bypass valves and an unanticipated main steam isolation signal. The main steam isolation signal only slightly complicated the Unit 3 operators response to the loss-of-offsite power event.
- A check-valve leakage problem in the Unit 3 safety injection system resulted in operators having to manually depressurize the low-pressure safety inject system three times during the event. This posed an unnecessary additional distraction for the event.
- Two Magna-Blast circuit breakers failed to operate during recovery operations in Unit 1 and Unit 3 which delayed electrical system recovery efforts.
- Limited equipment affected the ability to manually drain condensate from the turbine-driven auxiliary feedwater system and that systems availability.

Despite the number of challenges to the plant operating staff and management, all three units were safely shutdown, placed in a stable condition immediately following the loss-of-offsite power event, and power restoration efforts began immediately. With the exception of the local 525 kV transmission grid surrounding the Palo Verde switchyard, the Arizona, California, and Nevada electrical grid remained stable, only noting the fault through some minor frequency and voltage fluctuations. This was notable considering the amount of generation lost due to propagation of the fault. The total local generation lost during the event included the three Palo Verde units, three co-generation units at the Red Hawk generating station, and three co-generation units at the Arlington generating station for a total of approximately 5,500 megawatts of electrical generation.

In the following sections, each pertinent aspect of the event is discussed in detail. Section 2.0 contains the teams findings in the area of system performance and design. Section 3.0 contains the teams findings in the area of human performance and procedures. Section 4.0 contains the teams findings associated with the facilities interaction with off-site entities. Section 5.0 includes a summary of the NRC analysis associated with overall risk significance of the event. Finally, Section 6.0 contains the teams overall assessment of the licensee's response to the event.

1.2 System Descriptions

1.2.1 Off-site Power Transmission and Distribution Systems

a. General

The Palo Verde Nuclear Generating Station is connected by its associated transmission system to the Arizona-New Mexico-California-Southern Nevada extra high voltage (EHV) grid which is interconnected to other EHV systems within the Western System Coordinating Council (WSCC).

b. Palo Verde Nuclear Generating Station Switchyard

The PVNGS switchyard consists of two 500 kv buses which are connect to the three PVNGS 525/22.8 kv main step-up transformers, and seven transmission lines, using a breaker and a half scheme. The seven 525 kV transmission lines comprising the Palo Verde transmission system are situated in four corridors from the PVNGS switchyard as follows:

One line to the Devers substation (240 mi.)
Three lines to the Hassayampa substation (3 mi.)
One line to the Rudd substation (25 mi.)
Two lines to the Westwing 500 kv substation (44 mi.)

c. West Wing Substation

The Westwing substation is comprised of a two bus 230 kV section and a two bus 500 kV section. The 500 kV section is connected to the adjacent 230 kV Westwing section through three 525/345/230 kV load tap changing transformers. The Westwing 230 kV buses are connected to the transmission system as follows:

One line to the Surprise substation
One line to the Pinnacle Peak substation
One line to the Liberty substation
One line to the Agua Fria substation
One line to the Deer Valley substation
One line to New Waldell substation
Two 230/69 kV transformers feeding the APS distribution system

The above lines are connected to the Westwing substation through a breaker an a half scheme such that at least two circuit breakers must be opened to isolate a line from the substation.

d. Hassayampa Switchyard

The Hassayampa substation is located three miles from the PVNGS switchyard. It consists of two 500 kv buses connected to the PVNGS switchyard and several other generating stations and substations through a breaker an a half scheme, as follows:

Three lines to the PVNGS switchyard (3 mi.)
Two lines to the Red Hawk Switchyard (1 mi.)
One line to the Jojoba substation (20 mi.)
One line to the Noth Gila substation (110 mi.)
One line to the Mesquite switchyard (0.5 mi.)
One line to the Arlington Valley switchyard (1 mi.)
One line to the Harquahala Switchyard (30 mi.)

The three lines to the PVNGS switchyard were equipped with negative sequence relays intended to serve as pole mismatch protection for the Hassayampa PCBs. APS stated that this relaying was set to trip on 20% negative sequence current after a definite time delay of 5 seconds.

1.2.2 On-site Power Distribution System

a. General

Power is supplied to the PVNGS auxiliary buses from the offsite power supply through thee startup transformers. In addition, during normal plant operation, power for the onsite non-Class 1E ac system is supplied through the unit auxiliary transformer connected to the main generator isolated phase bus. The non-Class 1E ac buses normally are supplied through the unit auxiliary transformer, and the Class 1E buses normally are supplied through the startup transformers. Each unit's non-Class 1E power system is divided into two parts. Each of the two parts supplies a load group including approximately half of the unit auxiliaries. Three startup transformers connected to the 525 kV switchyard are shared between Units 1, 2, and 3 and are connected to 13.8kV buses of the units. Each startup transformer is capable of supplying 100% of the startup or normally operating loads of one unit simultaneously with the engineered safety feature (ESF) loads associated with two load groups of one other unit. The 4160v class 1E buses are each normally supplied by an associated 13.8/4.16 kv auxiliary transformer, and receive standby power from one of the six standby diesel generators. The Class 1E 4160 V system supplies power to 480V and lower distribution voltages through 18 4160/480V load center transformers.

b. Palo Verde Nuclear Generating Station Generator Protective Relaying

The main generator protection schemes feature relaying intended to protect the generators against internal as well as external faults. Protection against external faults includes backup distance relaying and negative sequence time over current relaying. The backup distance relaying provides backup protection for 24 kV and 525 kV system faults close to the switchyard. The distance relay operates through an external timer. If the fault persists and the time delay step is completed, a lockout relay trips the unit aux transformer 13.8 kV breakers, generator excitation, 525 kV generator unit breakers, main turbine and the main transformer cooling pumps. The lockout relay also initiates transfer of station auxiliary loads.

The generator negative sequence time over current relay provides generator protection against possible damage from unbalanced currents resulting from prolonged faults or unbalanced load conditions. The relay operates through a lockout relay to trip the unit auxiliary transformer 13.8kV breakers, generator excitation, 525 kV generator unit breakers, main transformer cooling pumps and the main turbine. The negative sequence relay also incorporates a sensitive alarm circuit that, in conjunction with a separately mounted ammeter, alerts operator action on relatively low values of negative sequence current (just above normal system unbalance).

c. Emergency Diesel Generators

The Class 1E alternating current system distributes power at 4.16 KV, 480V, and 120V to all Class 1E loads. Also, the Class 1E alternating current system supplies power to certain selected loads that are not directly safety-related but are important to the plant . The Class 1E alternating current system contains standby power sources (i.e., emergency diesel generators) that automatically provide the power required for safe-shutdown in the event of loss of the Class 1E bus voltage.

In the event that preferred power is lost, the Class 1E system functions to shed Class 1E loads and to connect the standby power source to the Class 1E bus. The load sequencer then functions to start the required Class 1E loads in programmed time increments.

d. Station Blackout Gas Turbine Generator Sets

A non-safety related Alternate AC (AAC) power source consisting of two redundant gas turbine generators is available to provide power to cope with a four hour station blackout event in any one nuclear unit. One GTG is analyzed to supply all required station blackout loads, which are located on the 'A' train.

Each GTG has a minimum continuous output rating of 3400kW at 13.8kV under worst case anticipated site environmental conditions. This rating is sufficient to provide power to the loads identified as being important for coping with the SBO.

e. Technical Support Center Emergency Diesel Generator

The technical support center diesel generator provides standby alternating current to the 480 V electrical distribution panel that supplies all electrical power to the technical support center emergency planning facility. The diesel engine is cooled by a self-contained cooling water system with an air cooled radiator. The radiator is in turn cooled by an electric motor driven fan. The fan motor is powered by the technical support center electrical power distribution panel. Normal electrical power for the technical support center comes from the off-site electrical power supply to Unit 1. During a loss of off-site power, when power is lost to the technical support center electrical power distribution panel, the technical support diesel generator automatically starts and re-energizes the technical support center electrical loads, including the diesel engine radiator cooling fan.

1.2.3 Chemical Volume and Control System

The chemical and volume control system controls the purity, volume, and boric acid content of the reactor coolant. Water removed from the reactor coolant system is cooled in the regenerative heat exchanger. From there, the coolant flows to the letdown heat exchanger and then through a filter and a demineralizer where corrosion and fission products are removed. It is then sprayed into the volume control tank and returned by the charging pumps to the regenerative heat exchanger where it is heated prior to returning to the reactor coolant system.

When the vital 4160 VAC buses are de-energized, the charging pump breakers must be manually reset and the pumps restarted from the control room. Therefore, no charging flow is assumed for 30 minutes after the time of trip to allow for resetting the breaker and performing manual alignment of one of three gravity-fed boration pathways to the charging pump suction.

Following a loss of offsite power, letdown will isolate automatically due to the loss of nuclear cooling water to the letdown heat exchanger or by operator action. When charging is restarted, the resulting mismatch between letdown and charging will cause volume control tank level to decrease. To reduce the chance of losing suction to the

charging pumps, the volume control tank level is monitored by two nonsafety grade instrument channels. Alarms are provided on low level and if the two channels differ significantly. The use of two channels of different types (one has a wet reference leg and the other is dry) decreases the probability of operator error inaligning the boration systems should one channel fail.

1.2.4 Auxiliary Feedwater System

The Auxiliary Feedwater System (AFW) provides an independent means of supplying water to the Steam Generators during emergency operations when the Feedwater System is inoperable. AFW maintains the water inventory necessary to allow a Reactor Coolant System cooldown at a maximum rate of 75°F/h down to a temperature of 350°F. It also provides the necessary water inventory for startup, normal shutdown and hot standby conditions.

1.3 Preliminary Risk Significance of Event

The Nuclear Regulatory Commission's Management Directive 8.3, "Incident Investigation Program," documents the NRC's formal process conducted for the purpose of accident prevention. This directive documents a risk-informed approach to determining when the agency will commit additional resources for further investigation of an event. The risk metric used for this decision is the conditional core probability. Because there is a lack of complete information at the time of initial decision-making, a preliminary evaluation is performed.

A loss of offsite power is a significant event at any nuclear facility, and more so for a Combustion Engineering plant without primary system power-operated relief valves, because of the inability to perform a reactor coolant system feed and bleed evolution. To evaluate this event, the analyst used the Standardized Plant Analysis Risk Model for Palo Verde (SPAR), Revision 3 model, and modified appropriate basic events to include updated loss of offsite power curves published in NUREG CR-5496. The analyst evaluated the risk associated with the Unit 2 reactor because it represented the dominant risk of the event.

For the preliminary analysis, the analyst established that a loss of offsite power had occurred and that the event may have been recovered at a rate equivalent to the industry average. Both Emergency Diesel Generator A and Charging Pump E were determined to have failed and assumed to be unrecoverable. Additionally, the analyst ignored all sequences that included a failure of operators to trip reactor coolant pumps, because all pumps trip automatically on a loss of offsite power. The conditional core damage probability was estimated to be 6.5×10^{-4} indicating that the event was of substantial risk significance and warranted an augmented inspection team.

2.0 System Performance and Design Issues

2.1 Offsite Power Reliability and Independence Issues

a. Inspection Scope

The team reviewed design drawings associated with the Palo Verde, Hassayampa, West Wing, Devers, and Rudd switch yards and substations. In addition, the team conducted interviews with licensee personnel, Arizona Public service personnel, and Salt River Project personnel involved in the investigation. Finally, the team reviewed the sequence of event and alarm printouts in detail to develop a comprehensive understanding of the event progression.

b. Observations and Findings

The 500 kv system upset at the PVNGS switchyard originated with a fault across a degraded insulator on the 230 KV Liberty line from the Westwing substation. Protective relaying detected the fault and isolated the line from the Liberty substation. The protective relaying scheme at the Westwing substation received a transfer trip signal from Liberty actuating the AR relay in the tripping scheme for circuit breakers 1022 and 1126. The AR relay had four output contacts, all of which were actuated by a single lever arm. The tripping schematic showed that contacts 1-10 and 2-3 should have energized redundant trip coils in PCB 1022, while contacts 4-5 and 6-7 should have energized redundant trip coils in PCB 1026.

PCB 1126 tripped, demonstrating that the AR relay coil picked up, and least one of the AR relay contacts, 1-10 or 2-3, closed. PCB 1022 did not trip. Bench testing by APS showed that, even with normal voltage applied to the coil, neither of the tripping contacts for PCB 1022 closed. The breaker failure scheme for PCB 1022 featured a design where the tripping contacts for the respective redundant trip coils also energized redundant breaker failure relays. Since the tripping contacts for PCB 1022 apparently did not close, the breaker failure scheme for PCB 1022 also was not activated, resulting in a persistent uncleared fault on the 230 kV Liberty line.

Various transmission system events recorders show that during approximately the first 12 seconds after fault inception, several transmission lines on the interconnected 69 kv, 230 kv, 345, and 525 kv systems tripped on overcurrent, including lines connected to the Westwing, Hassayampa substations. Also during the first 12 seconds, two Red Hawk combustion turbines and one Red Hawk steam turbine power plants tripped, and the fault alternated between a single line to ground fault to a two line to ground fault, apparently as a result of a failed shield wire falling on the faulted line. After 12 seconds, the fault became a three phase to ground fault, and additional 525 kv lines tripped.

At approximately 17 seconds after fault inception, the three tie lines between the PVNGS switchyard and the Hassayampa substation tripped simultaneously due to action of their negative sequence relaying, thereby isolating the fault from the several co-generation plants connected to the Hassayampa substation. Approximately 24 seconds after fault inception the last two 525 kv lines connected to the PVNGS switchyard tripped, isolation the switchyard from the transmission system. At approximately 28 seconds after fault inception, the three PVNGS generators were isolated from the switchyard, and by approximately 38 seconds all remaining lines feeding the fault had tripped and the fault was isolated.

Reliability Issues

The degraded insulator was caused by external contamination and did not represent a concern relative to the reliability of the insulation of the 230 kv transmission system. The failed AR relay and the lack of a robust tripping scheme raised concerns relative to the maintenance, testing, and design of 230 kv system protective relaying. Interviews with APS T&D personnel indicated that the Westwing substation where the relay failure occurred was subject to annual maintenance and testing. Following the event, the failed AR relay was removed from service by APS and visually inspected by the NRC team at PVNGS. The relay showed no apparent signs of contamination or deterioration. Although the team considered the maintenance interval to be reasonable, the team did not determine the degree of rigor applied in testing the relaying scheme. For instance, it is doubtful that the testing included methods common in the nuclear industry such as verifying that each contact in the tripping scheme functioned properly. As noted earlier, the tripping scheme lacked redundancy that may have prevented the failure of the protective scheme to clear the fault. APS reviewed the design of the Westwing substation as well as all other substations connected to the PVNGS switchyard, and found that only the Liberty and Deer Valley lines at the Westwing substation featured a tripping scheme with only one AR relay. All of the newer lines featured two AR relays. However, APS also noted that the middle breakers in the breaker and a half scheme at the Westwing substation only contained one trip coil, as opposed to two trip coils in the bus connected breakers. This feature was believed to be representative of the design at other APS substations. In order to improve reliability, APS modified the tripping schemes for the Liberty and Deer Valley lines to feature two AR relays enegizing separate trip coils. APS also stated that they would evaluate the feasibility of installing two trip coils in all PCBs. The team noted that even considering the completed and proposed modifications, all of the tripping circuits were still powered by a single 125VDC system, so "single failure" vulnerabilities will remain. APS stated that 125 DC system reliability was enhanced by redundant battery chargers and alarms that annunciate in the APS control center. Grid reliability studies performed by utilities typically have not considered the occurrence of an uncleared fault on the transmission system. This event, and the specific concerns identified relative to the design and testing of transmission system protective relaying suggest vulnerabilities may exist that render the offsite power supplies less reliable than previously assumed.

<u>Independence of Offsite Power Supplies</u>

GDC 17 requires that power from the offsite transmission network be supplied by "two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions".

Ex2

The uncleared fault resulted in tripping of transmission lines both locally, and at remote substations. Lines at several interconnected transmission voltage levels tripped, commencing a few cycles after fault inception, and continuing for another 38 seconds. Even remote lines were tripped by inverse time overcurrent relays, which were not intended to protect against remote faults, but nevertheless succumbed to the fault because its duration.

Ex2

Another concern was raised by the simultaneous tripping of the three Hassyampa tie lines. The three Hassayampa tie lines featured negative sequence relaying intended to serve as pole mismatch protection. The scheme featured a 5 second definite time delay to avoid spurious tripping due to faults. Although these individual lines could have been considered as separate sources of offsite power, this event demonstrated that the lines were subject to simultaneous failure resulting from unintended operation of the relaying scheme. SRP has stated that the negative sequence relaying has been disabled and pole mismatch protection is being implemented by alternate relaying.

2.2 Unit 1, Atmospheric Dump Valve 185 Failure

a. Inspection Scope

The team reviewed the operators' responses and control room logs relating to the loss of manual control of the atmospheric dump Valve 185 during the performance of Procedure 40EP-9EO10 "Loss of Offsite Power/ Loss of Forced Circulation," Revision 10.

b. Observations and Findings

The team identified an unresolved item associated with the control of atmospheric dump Valve ADV-185 in Palo Verde Unit 1.

Following the June 14, 2004, loss-of-offsite-power event at Palo Verde Unit 1, atmospheric dump Valve ADV -185 failed to operate properly while being manually operated. Operators in the control room observed that the valve had drifted closed, contrary to the manual controller setting. The operators were able to adjust Valve ADV-185 from the controlling station; however, the valve position would not remain in the desired position. Licensee personnel initiated CRDR 2716011 to determine the root cause of the failure and perform corrective actions necessary to address the failure.

The impact on the control of primary plant temperature during this event was minimal. The operator had the skill and ability to readily diagnose and overcome this anomaly. All other atmospheric dump valves on Unit 1 responded properly to manual control signals and presented no further challenges to the control room operators.

Licensee personnel identified the apparent cause of the malfunction as internal leakage equalizing around a pilot valve causing the valve to shut. The valve and it's associated control circuit were quarantined and maintenance personnel were troubleshooting the components to determine the root cause of the malfunction.

This issue is identified as Unresolved Item 05000528/2004012-XXX to evaluate the root cause determination and corrective actions associated with the atmospheric dump Valve ADV-185 drifting shut when in manual control.

2.3 Unit 1, Letdown Heat Exchanger Isolation Failure

a. Inspection Scope

The team reviewed the licensee's temporary modification Package 2594804 and CRDR 2715667 documenting the system response during the event. The team also interviewed plant personnel and reviewed control room logs and temperature plots to determine the impact of the high temperature on the letdown system

b. Observations and Findings

The team identified an unresolved item associated with the design control of the letdown system.

During the 14 June, 2004, loss-of-offsite-power, the Unit 1 letdown system did not operate as expected when fluid temperatures exceeded the alarm setpoint. The letdown system bypassed the ion exchanger and the filter at 140°F, as expected. However, the team determined that a temporary modification to bypass a flow sensor had been installed which removed the signal to isolate the system on low flow. The system was designed to isolate the letdown system if temperature at the outlet of the non-regenerative heat exchanger exceeded 148°F. The isolation did not occur as expected.

Licensee personnel identified the apparent cause of the system not isolating as expected was the failure of the temporary modification to fully address the functioning of the letdown control system during a loss of power to the controller. The team noted that, as a consequence of a loss-of-offsite-power, the nuclear cooling water flow is lost to the non-regenerative heat exchanger. The team also noted that, when power is restored to the system, the valves would be in a manual mode of operation. Therefore, flow through the system would not be secured by the control system. The team found that the temporary modification resulted in the bypass of the backup initiating signal for isolating the system in the event that flow was lost.

The impact on the plant systems and personnel were minimized when the ion exchanger bypass valves actuated to remove high temperature water from the resin. However, the introduction of high temperature water created a distraction when, as a result of paint and insulation being heated, the fire brigade was activated for a report of smoke/fumes emanating from . The report required the building to be walked down by operators. Licensee personnel performed a visual inspection of the system and completed a stress analysis to identify locations that exceeded the maximum allowable stress.

The team noted that the maximum allowable stress associated with 350°F fluid temperature was 27,475 psi. The team determined that a weld on the drain for purification Filter F36 was the only area of that may have exceeded the maximum allowable stress. Licensee personnel performed a visual inspection of the affected weld, and removed the filter element to determine if any damage occurred. Because the filter element is rated for 180°F for 1 hour, and there was no indication of damage, the licensee personnel concluded that the weld was not subjected to the temperatures that could have caused excessive stress on the weld.

With respect to the extent of condition, the team found that Unit 1 was the only unit that had this modification installed to bypass the low flow isolation signal. Therefore, the team had no concerns with the other units.

The team identified the issue of design control as Unresolved Item 05000528/2004012-XXX. The issue is unresolved pending NRC review of the root cause and identification/performance of corrective actions resulting from CRDR 2715667.

2.4 Unit 2, Train A Emergency Diesel Generator Failure

a. Inspection Scope

The team interviewed licensee representatives and reviewed the sequence of events that led up to the failure of the Unit 2 Train A emergency diesel generator to determine the apparent cause. The team also reviewed the effects the loss of the diesel generator had on the recovery of the event; the action plan for determining the root cause (Condition Report/Disposition Request (CRDR) 2715709); and the extent of condition of the apparent cause.

b. Observations and Findings

The team found that the apparent failure of the Unit 2 Train A emergency diesel generator was a failed diode in Phase B of the voltage regulator exciter circuit. The diode failure resulted in a reduced excitation current which was unable to maintain the voltage output with the applied loads.

At approximately 07:41:15 am, the Unit 2 Train A emergency diesel generator received a start signal as a result of an undervoltage signal on the Train A 4.16KV Class 1E bus. The emergency generator started, came up to speed and voltage, and energized the bus at approximately 07:21:23 am, within the 10 seconds allowed by design. Approximately 5 seconds later, the Train A battery chargers, control element drive mechanism cooling units, and the containment cooling units were sequenced onto the bus. The essential cooling water pump was sequenced onto the bus approximately 15 seconds after the first loads.

The team noted that, at approximately the same time the essential cooling water pump was energized, the output voltage from the emergency diesel generator began to fail. The control room operators observed the voltage and current indications in the control room were a zero and had an auxiliary operator observe the indications locally, at the emergency diesel generator control panel. The indications were also zero. The control room operators initiated a manual emergency trip of the diesel at approximately 07:56:21 am. The team found these actions to be appropriate for the circumstances.

The team found that the failed emergency diesel generator did not have a large impact on the recovery, but did result in having only one train of safety equipment available. The only apparent effect of the loss of Train A safety-related equipment was associated with the charging pumps (see Section 4.1, below).

The team noted that licensee engineers and maintenance personnel developed a comprehensive plan to troubleshoot the failure (CRDR 2715709). The plan was methodical and prioritized. The team found that the troubleshooting activities were thorough and well controlled, resulting in the identification of the failed diode in Phase B of the exciter circuit. The failure resulted in a half-wave output with significantly reduce

current that led to the loss of adequate excitation to maintain the required voltage for the applied loads.

The team found that, while this diode was common to all the emergency diesel generators at the Palo Verde Nuclear Generating Station, there was insufficient data to indicate there was a common mode problem. A review of the industry database on component failures revealed only one other failure of this specific model diode. That failure was in 1997. As such, the team found the extend of condition reiew by licensee personnel to have been appropriate for the circumstances.

The team noted that the failed diode had been replaced during the fall 2003 refueling and steam generator replacement outage. This diode had been subject to approximately 75 hours of operation. Licensee personnel had plans to perform additional testing to determine the root cause, if possible, of the diode failure. Unresolved Item 05000529/2004012-XXX is opened to evaluate the corrective actions and root cause determination associated with the emergency diesel generator failure. This item has potential problem identification and resolution aspects.

2.5 Unit 3, System Interactions During Event

a. Inspection Scope

The team reviewed the licensee's CRDR 2715659 documenting the steam system bypass response during the event. The team reviewed control room logs; temperature, voltage and frequency plots; steam pressure and flow plots; primary coolant flow; and nuclear power plots to determine the magnitude and correlation of key events. The team also interviewed various personnel that were either involved in the event or in the analyses of the event. The team conducted an extensive review of the plant computer alarm log printout to establish a time line of the event. The team conducted an analysis of the key events on Unit 3, as indicated by the alarm printout, and noted several differences in the progression of the loss-of-offsite-power event response when compared to the responses for Units 1 and 2 and as described in the Final Safety Analysis Report (FSAR).

b. Observations and Findings

The team identified two unresolved items. The first item is associated with the automatic main steam-line isolation in Unit 3 and tasks the follow-up review to evaluate the response of the bypass control system response in all three units after the loss-of-offsite-power and compare the response to those assumed in the plant safety analysis. The second item is associated with reviewing the licensees root cause for the Unit 3 reactor trip on a variable over-power signal and the licensees evaluation of the impact of the high frequency on plant equipment, as well as the extent of condition once the cause is determined.

The team noted that Unit 3 experienced an automatic main steam-line isolation. Licensee engineers's attributed the automatic isolation to a steam bypass control system anomaly that caused a decrease in steam pressure. The team found, through interviews with licensee engineers, the apparent cause of the "anomaly" was the result of a momentary loss of power to Panel D11 with the control system being re-energized

in the automatic mode, vice manual. According to the licensee engineers, this power loss initiated a 30-second timer that disconnected the valve control signals from the control cabinet. When the 30-second timer completed, all eight valves modulated open in about 14 seconds. This resulted in a rapid drop in steam-line pressure, automatically initiating a main steam-line isolation signal.

The PVNGS FSAR, Revision 12, Section 1.8, "Conformance to NRC Regulatory Guides," documents that the licensee took exception to the separation criterion of NRC Regulatory Guide 1.75, "Physical Independence of Electric Systems," Revision 1, for the power supplies to Panel D11. As a result, Panel D11 has both a non-vital power supply (normal) and a vital power supply (backup). Upon loss of normal power, the supply automatically transfers to the backup supply. After the normal supply returns, the panel must be manually transferred back to the normal supply. Upon a total loss of power to Panel D11, the steam bypass control system will be unable to automatically respond to any challenges (FSAR, Section 7.2.2.4.1.2.1). The team also noted that the power supply configuration was identical on all three units. However, Units 1 and 2 did not respond the same as Unit 3.

The team noted that, in each subsection of the FSAR listed below, the steam bypass control system is assumed to be unavailable because it is either deenergized or in manual. During the loss-of-offsite-power event, the team found that the system was reenergized and operated in automatic. The team noted that this system response may not be as described in the licensee's safety analysis.

6.3.3.5D.	For all break sizes, the reactor trip will result in a turbine trip and the subsequent loss of offsite power will result in the loss of main feedwater flow. Since the steam bypass control system is not available due to loss of condenser vacuum on loss of offsite power . . .
7.2.2.4.1.2.1A.	The SBCS and RPCS will be unable to automatically respond to any challenges on a failure of distribution panel E-NNN-D11.
7.2.2.4.1.2B	. . . the LOFW [loss-of-feedwater] event presented in subsection 15.2.7 assumed that the PPCS, SBCS, and RRS are in the manual mode of operation, unable to automatically respond to challenges.
15.1.4.2	Case 1 Since the steam bypass control system is assumed to be in the manual mode with all bypass valves closed . . .
15.1.4.2	Case 2 Since the steam bypass control system is assumed to be in the manual mode with all bypass valves closed . . .

15.2.3.1	. . . in this analysis both the SBCS and RPCS are assumed to be in the manual mode and credit is not taken for their functioning.
15.3.1.1	The only credible failure which can result in a simultaneous loss of power is a complete loss of offsite power. In addition, since a loss of offsite power is assumed to result in a turbine trip and renders the steam dump and bypass system unavailable, the plant cooldown is performed utilizing the secondary valves and atmospheric dump valves (ADVs). . . The loss of offsite power will make unavailable any systems whose failure could affect the calculated peak pressure. For example, a failure of the steam dump and bypass system to modulate or quick open and a failure of the pressurizer spray control valve to open involve systems (steam dump and bypass system and pressurizer pressure control system (PPCS)) which are assumed to be in the manual mode as a result of the loss of offsite power and, hence, unavailable for at least 30 minutes.
15.3.1.2C.	The turbine is assumed to trip on loss of offsite power. The loss of offsite power produces a loss of load on the turbine which generates a turbine trip signal. The turbine stop valves are closed as a result of the trip. The steam bypass control system becomes unavailable due to the loss of offsite power and subsequent loss of condenser vacuum.
15.3.4.1	The assumed loss of AC renders the steam bypass control system inoperable as a result of the loss of circulating water pumps.
15.3.4.2C.	The loss of offsite power causes a loss of power to the plant loads and the plant experiences a simultaneous loss of feedwater flow, condenser inoperability, and a coastdown of all reactor coolant pumps.
15.3.4.3.1C.	The loss of offsite power also causes a loss of main feedwater and condenser inoperability. The turbine trip, with the steam bypass control system (SBCS) and the condenser unavailable, leads to a rapid buildup in secondary system pressure and temperature . . .
15.4.2.2D.	Following the generation of a turbine trip on reactor trip, the main feedwater control system (FWCS) enters the reactor trip override mode and reduces feedwater flow to

5% of nominal, full power flow. Since the steam bypass control system (SBCS) is assumed to be in manual mode with all bypass valves closed, the main steam safety valves (MSSVs) open to limit secondary system pressure and remove heat stored in the core and the RCS.

15.4.2.3B.	All the control systems listed in table 15.4.2-2, except the steam bypass control system, were assumed to be in the automatic mode since these systems have no impact on the minimum DNBR obtained during the transient. The steam bypass control system is assumed to be in manual mode because this minimizes DNBR during the transient.
15.4.8.3C.	The steam bypass control system is inoperable on loss of offsite power and therefore is unavailable.
15.5.2.1	The loss of normal ac power results in loss of power to the reactor coolant pumps, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control system, the reactor regulating system, the feedwater control system, and the steam bypass control system.
15.5.2.3C.	Since the steam bypass control system is in the manual mode . . . The unavailability of the steam bypass valves . . .
15.6.3.1.2D	Since the SBCS is assumed to be in manual mode with all bypass valves closed . . .
15.6.3.3.1A.	The ADVs [atmospheric dump valves] are used due to the unavailability of the steam bypass control system due to loss of offsite power.
15.6.3.3.3.1C.	The loss of offsite power also causes the steam bypass system to the condenser to become unavailable.

The team identified the determination of the root cause for the main steamline isolation, the evaluation of the response of the bypass control system, and the determination of the analyzed design to be Unresolved Item 05000530/2004012-XXX.

During the teams review of the time-line, it was noted that the main turbine stop valves closed on each unit at approximately 07:41:21 am. The Units 1 and 2 reactor coolant pumps had tripped on undervoltage approximately 1-second prior to the turbine trips, and the reactors tripped on anticipatory low departure from nucleate boiling ration within 1-second of receipt of the turbine trips. However, on Unit 3, the reactor tripped on variable over-power approximately 1-second after the other units. Next, the team noted that the Unit 3 main generator tripped approximately 1-second after the reactor trip on a volts/hertz signal, while the other units' main generators did not trip on volts/hertz

signals until approximately 3.5 seconds after the reactor trips. And, approximately 5 seconds after the Units 1 and 2 reactor coolant pumps tripped on undervoltage, the Unit 3 reactor coolant pumps tripped on undervoltage. The team also noted, from the review of the post-trip review data, that all three units experienced post-event frequency increases to approximately 67 hertz.

During the loss-of-offsite power event, the Unit 3 reactor coolant pumps remained connected to the substation bus while the turbine was in a overspeed condition. Licensee engineers concluded that the bus voltage was maintained because of an unexpected response of the Unit 3 generator's excitation circuit. As a result of the excitation circuit response, the excitation, and therefore the output voltage, remained high, delaying the load shed and tripping of the reactor coolant pumps.

Since the Unit 3 reactor coolant pumps remained operating longer, they turned at the higher frequency, the flow increased through the critical reactor core. This increase in flow (approximately 108.2 percent of design flow), produced a power of approximately 109 percent, as read on excore nuclear instruments. This positive rate of change in reactor power generated a variable over-power-trip signal to shutdown the reactor.

The team reviewed the licensee's evaluation of the increased reactor coolant flow and noted that the estimated flow of 108.2 percent was less than the evaluated limit of 110.4 percent of design volumetric flow. According to the licensee's analyses, the most limiting component of each reactor coolant pump was the motor flywheel which was designed for 125 percent of rated speed. The team noted that this value was not approached during the event. The team agreed with the licensee's conclusion that there was no impact to the continued power operation with respect to fuel grid-to-rod fretting, vessel hydraulic uplift forces, and fuel mechanical design.

While all three turbine generators were in an over-speed condition and connected to the plant busses, all connected loads experienced a higher frequency. The reactor coolant pumps for Units 1 and 2 were not exposed to the high frequency condition because their undervoltage relays actuated before the higher frequency was attained.

The team found that the plant responses observed during this event were apparently different from those described in the FSAR. The evaluation of the root cause for the Unit 3 reactor trip on a variable over-power signal and the evaluation of the impact of the high frequency on plant equipment, as well as the extent of condition once the cause is determined is considered an Unresolved Item XXXX,

2.6 Unit 3, Reactor Coolant Pump 2B Lift Oil Pump Breaker

a. Inspection Scope

The team reviewed the thermal overload curves for the lift oil pumps and the operators' responses to the loss of the pump with regard to restoring forced circulation in the primary plant. The team also interviewed plant personnel, and reviewed CRDR 2715659 and control room logs regarding the activities surrounding the failure of the lift oil pump to start.

b. Observations and Findings

The team identified two unresolved items associated with the design of the lift oil system and the emergency operating procedure to start reactor coolant pumps.

Following the 14 June, 2004 loss of Offsite Power, the Unit 3 reactor coolant Pump 2B lift oil pump thermal overloads were actuated during the recovery of reactor coolant pumps. The team noted that the motor running current was within 0.1 amp of the overload rating. At this level of running current, the team found that the overloads would actuate in approximately 600 seconds. Licensee personnel identified the apparent cause of the trip of the lift oil pump was operating the pump in excess of 10 minutes.

The team found that the thermal overload sizing and motor running amperage are common among the three units. The team noted that the motors for the lift oil pumps had been replaced and the thermal overloads resized through the design change process.

The team identified the evaluation of the adequacy of the design change associated with the lift oil pumps to be Unresolved Item 05000528/2004012-XXX; 05000529/2004012-XXX; 05000530/2004012-XXX. Licensee personnel initiated CRDR 2715659 to track this issue.

To restart reactor coolant pumps, Procedure 40EP-9EO10 Appendix 1, states, in part:

> 15. <u>Ensure</u> the appropriate lift oil pump has been running for 7 minutes or more.

The team found that the procedure may not have contained sufficient detail to ensure the safe and continued operation of the lift oil pumps. The team identified the evaluation of the adequacy of Procedure 40EP-9EO10 with respect to the operation of the lift oil pumps to be Unresolved Item 05000528/2004012-XXX; 05000529/2004012-XXX;

2.7 Unit 3, Low Pressure Safety Injection System In-Leakage

a. Inspection Scope

The team reviewed the CRDR 2715659 documenting the safety injection system response during the event. Plant personnel were interviewed and control room logs and plots were reviewed to determine the impact of the in-leakage to the safety injection system.

b. Observations and Findings

The team identified two unresolved items related to the safety injection check valve leakage. The first item is associated with the root cause determination, and prior corrective actions for previous leakage issues and response to industry operating experience and generic communications. The second item is associated with the adequacy of the inservice testing program for testing and demonstrating the check valves capable of performing their design basis functions.

During the loss-of-offsite-power event, there were several instances of in-leakage to the Unit 3 safety injection system through check Valve RCEV-217. This in-leakage

occurred through 14 inch Borg-Warner check valves and pressurized the safety injection header to reactor coolant Loop 2A. The team noted that, when this system is pressurized above 1850 psig, Train B of the low pressure safety injection system is rendered inoperable. The team also noted that control room operators monitored this condition and utilized an annunciator with a setpoint of 1000 psig.

From the control room logs, the team noted that the operators depressurized the system three times during the response to the loss-of-offsite-power. The operator performed the venting evolution by implementing alarm response Procedure 40AL-9RK2B, **"NEED TITLE,"** Revision **?**. Licensee personnel evaluated each instance of pressure increase to ensure that an intersystem loss-of-coolant-accident had not occurred. The criterion for determining that if there was an intesystem loss-of-coolant-accident was a pressure increase of more than 1100 psig in less than 1 minute.

The team noted that licensee personnel determined that the apparent cause of the leakage was the seat and disc did not come to equilibrium temperatures at the same time. The licensee personnel determined the problem was most likely to occur when the primary plant is changing from a cooled down condition to normal operating temperatures. Licensee personnel initiated CRDR 2715659 to track this item. All three units have these check valves and have experienced back leakage through them during changing plant conditions.

The team identified Unresolved Item 05000528/2004012-XXX; 05000529/2004012-XXX; 05000530/2004012-XXX for the determination of the root cause of the leaking check valve, as well as the extent of condition once the cause is determined. In addition to the root cause determination, this item is unresolved pending NRC review of the adequacy of the corrective action program and the events assessment program to address the generic concerns previously identified by the industry and the NRC, and through actual experience at Palo Verde.

The team found that the impact on the event was the number of distractions of operators attempting to respond to the loss-of-offsite power three times while depressurizing the system over a 7-hour period.

All units in Palo Verde have these check valves and have experienced back leakage through them during changing plant conditions. As a result, the team identified Unresolved Item 05000528/2004012-XXX; 05000529/2004012-XXX; 05000530/2004012-XXX for the evaluation of the adequacy of the inservice test program to correctly determine the operability of check valves.

2.8 Unit 1 and 3, General Electric Magna Blast Breaker Failures

a. Inspection Scope

The team reviewed the failure of two circuit breakers to close on demand during the recovery from the loss-of-offsite power. The team also interviewed licensee personnel associated with the investigation into the breaker failures.

b. Observations and Findings

The team identified an unresolved item associated with maintenance activities and operation of Magne-Blast circuit breakers.

The team noted that, while recovering from the loss-of-offsite-power, 13.8KV circuit Breakers 1ENANS06K and 3ENANS05D failed to close on demand from the control room. Electrical engineering and maintenance personnel determined the apparent cause of the failures to be the improper operation of the latching mechanisms due to poor lubrication and contamination by dirt. Licensee personnel initiated CRDR 2716019 to evaluate the failures, determine the root cause(s), and take any corrective actions identified.

The team noted that the initial response only involved a cycling of the breakers without any detailed troubleshooting. The team found that the licensee personnel considered this acceptable because of a known issue with hardened grease in Magne-Blast circuit breakers. While there is a well known issue with Magne-Blast circuit breakers failing to close as a result of hardened grease, the team found the licensee personnel's approach to be narrow. There have been at least generic communication issued by the NRC, dating to 1979, associated with Magne-Blast circuit breaker operation problems. In addition to the hardened grease issue, other causes of this type of breaker failure include misaligned latches, misaligned auxiliary contacts, and high-resistance contacts.

The team noted that each of the breakers had been refurbished in 2002. Breaker 1ENANS06K had been cleaned, inspected, and cycled during the last refueling outage earlier this year. The team found that the licensee personnel's determination of the apparent cause for the Unit 1 breaker was not supported by the facts because of the recent cleaning and inspection.

The team identified this as Unresolved Item 05000528/2004012-XXX; 05000530/2004012-XXX, pending NRC review of the circumstances surrounding the failure of the breakers, and the licensee's review and corrective actions associated with CRDR 2716019. This item has potential human performance and problem identification and resolution aspects.

3.0 Human Performance and Procedural Aspects of the Event

3.1 Auxiliary Feedwater System

a. Inspection Scope

The inspector evaluated the adequacy of the AFW system performance during the plant trip caused by the loss of offsite power. The inspector also assessed the operator response as it related to the AFW system. The inspection was accomplished through a review of documents and interviews with operators and engineering staff.

b. Observations and Findings

1. Thermally Inducted Vibration Transient

As part of the reactor trip response, operators manually started the essential motor-driven AFW pumps in all 3 units. Six hours after the reactor trip, Unit 1 operators placed

the non-essential motor-driven AFW pump into service and secured the essential pump. At this time, a plant operator reported high vibration for approximately 5 minutes in the main feedwater piping. The licensee generated CRDR 2715731 to document the high vibration. In Units 2 and 3, the non-essential pumps were placed in service, 17 and 29 hours after the reactor trips, respectively. No vibration was noted in Units 2 and 3.

There was no procedural requirement that compelled operators to secure the essential pump and place the non-essential pump in service. According to the Unit 1 operator, the basis for transferring from the essential pump to the non-essential pump was to allow operators to add chemicals to the feedwater, if needed. However, there was no need to add chemicals at the time that the transfer occurred in Unit 1.

The high vibration in the Unit 1 feedwater line occurred when the relatively cold auxiliary feedwater coming from the condensate storage tank mixed with the stagnant hot water in the insulated section of feedwater piping downstream of the injection point of the non-essential AFW pump. That section of feedwater became isolated as a result of a manual Main Steam Isolation Signal (MSIS) actuation required by the applicable Emergency Operating Procedure. There were no subsequent procedural cautions or guidance for preventing the introduction of the cold water into the feedwater system prior to that section of piping being allowed to cool down sufficiently. The placement of the non-essential AFW pumps into service in Units 2 and 3 did not result in high vibration because those sections of feedwater piping had apparently cooled enough to preclude a thermally induced vibration transient. The failure to establish procedural requirements to preclude thermally induced high vibration in the feedwater system when placing the non-essential AFW pump in service after an MSIS actuation and the adequacy of operator training in this area is an unresolved item.

2. Emergency Operating Procedure Adequacy

Unit 2 tripped at 7:41 a.m. on June 14, 2004 as a result of the Loss of Offsite Power. The completion of reactor post trip actions resulted in entry into the "Loss of Offsite Power/Loss of Forced Circulation" Emergency Operating Procedure (EOP) 40EP-9EO07, Rev. 10. Step 6. of this procedure requires a manual MSIS actuation. In addition to closing the main steam isolation valves, this step also causes closure of drains associated with two critical steam traps required to maintain operability of the turbine-driven AFW pump. With the steam traps unavailable, condensate can accumulate in the steam lines which can lead to an overspeed trip of the pump.

The EOP did not caution the operators that an MSIS would potentially make the turbine-driven AFW pumps inoperable. The EOP also did not direct the operators to implement the applicable sections of Normal Operating Procedure 40OP-9SG01, "Main Steam," Rev. 37, which provide the necessary instructions for manually draining those sections of piping necessary to maintain operability of the pump. This procedure requires that the piping associated with the critical steam traps be blown down every two hours until a dry steam condition is reached and then every six hours thereafter. On the day of the event, operators did not commence actions to drain the associated piping until 11 hours after the reactors tripped.

The failure of the EOP to provide a caution on impacting the turbine-driven AFW pump and the failure to have specific procedural direction to implement the system operating

requirements that ensure continued operability of the turbine driven AFW pump and the adequacy of operator training in this area is an unresolved item.

3. Drain Line Equipment

Without the steam traps available, condensate can accumulate in the steam lines and lead to a potential overspeed trip of the pump. A condensation induced overspeed trip of the Unit 1 pump occurred on April 24, 1990. At that time, Engineering Evaluation Request 90-AF-011 was generated to evaluate the root cause. The necessary corrective actions identified included directions to revise the operating and surveillance procedures to address maintaining the steam traps dry and directions to implement manual methods to ensure that the steam lines were maintained drained while in Modes 1, 2 and 3 with the turbine not on line.

After operators realized that draining of the piping associated with the critical steam traps was necessary to ensure continued operability of the turbine driven AFW pump, the applicable portions of the Main Steam normal operating procedure were referenced. The procedure required the installation of a vent rig tool constructed in accordance with Engineering Evaluation Request 92-SG-007 at each manual drain location. Consequently, each turbine-driven AFW pump required two vent rig tools. Operators were only able to find sufficient vent rig tools for one turbine-driven AFW pump. The failure to have adequate resources to be able to drain the piping in each of the three reactor Units delayed the restoration of critical equipment from a potentially inoperable status in a timely manner. The adequacy of the corrective actions from the previous overspeed trip and the failure to maintain adequate resources to limit the inoperability of critical equipment is an unresolved item.

4. Risk Insights

The auxiliary feedwater system is the most risk significant system in terms of its failure having a greater contribution to core damage frequency than any other plant system. With only enough vent rig tools to drain one turbine-driven AFW pump, operators elected to begin draining the Unit 1 pump. However, Unit 2 was in a higher risk condition as a result of having only one of two emergency diesel-generators available. Both emergency diesel-generators in Units 1 and 3 were operable. The A-train diesel-generator in Unit 2 had been manually tripped after a failed voltage regulator precluded the diesel-generator from accepting loads from the load sequencer immediately after the reactor trip. A trip of either the Unit 2 B-train emergency diesel-generator or the motor-driven essential AFW pump, being powered by the B-train emergency diesel-generator, would have resulted in a total loss of cooling water to the steam generators and consequently to the reactor coolant system. The decision making process that failed to direct resources to reduce the risk profile of the most affected Unit represents an unresolved item.

3.1 Unit 2, Train "E" Positive Displacement Charging Pump Trip

a. Inspection Scope

The team reviewed the emergency operating procedures and the operators' responses to the loss of offsite power with respect to the charging pumps to determine the effect

on the response to the event. The team also interviewed plant personnel and reviewed CRDRs 2716521 and 2716806 regarding the activities surrounding the charging pump operations.

b. Observations and Findings

The team identified an unresolved item associated with three examples of operators lack of adherence to the emergency operating procedures.

As the volume control tank level dropped to approximately 15 percent with Pump CHB-P01 operating, a control room operator recognized the need to transfer the charging pump suction from the volume control tank to the refueling water tank. Because of the loss of offsite power, control room operators were implementing the emergency operating procedure. The specific procedure was Procedure 40EP-9EO07, "Loss of Offsite Power / Loss of Forced Circulation," Revision 10.

Step 11 of the procedure states:

> **IF** VCT makeup is **NOT** available, **THEN** perform the following:
>
> a. **IF** RWT level is below or approaching 73%, **AND** the CRS desires to keep charging in service, **THEN** PERFORM **ONE**of the following:
>
> - Appendix 10, Charging Pump Alternate Suction to the RWT / Restoration
> - Appendix 11, Charging Pump Alternate Suction to the SFP / Restoration
>
> b. **IF** RWT level is above 73%, **THEN** perform the following:
>
> 1) **IF** three charging will be used, **THEN** stop the Boric Acid Makeup Pumps.
>
> 2) **IF** three charging pumps are will be (sic) used, **AND** a Fuel Pool Clean Pump is recirculating the RWT, **THEN** stop RWT recirc by stopping the appropriate Fuel Pool Cleanup Pump.
>
> 3) Open CHN-HV-536, RWT Gravity Feed to Charging Pump Suction.

4) Close CHV-UV-501, Volume Control Tank Outlet.

The team noted that the refueling water tank level was greater than 73 percent during this event. As such, the team found that the appropriate steps in the procedure for transferring the charging was Step 11.b.3) and 4). However, the Control Room Supervisor decided that Step 11.a. was appropriate because Valves CHN-HV-536 and CHN-UV-501 did not have power and the supervisor knew that the valves in Step 11.a. could be manually operated. The supervisor failed to consider that the valves in Step 11.b. could also be manually operated. By making this decision, the team considered the actions of the Control Room Supervisor not to be in accordance with the requirements of the emergency operating procedure for the plant conditions at the time (i.e., the refueling water tank level was greater than 73 percent). This is identified as the first example of Unresolved Item 05000529/2004012-XXX. Licensee personnel initiated CRDR 2716521 to evaluate the human performance error.

After deciding to implement Step 11.a., the Control Room Supervisor conducted a briefing with an auxiliary operator to discuss the manual transfer of the charging Pump CHE-P01 suction from the volume control tank to the refueling water tank using Appendix 10 to Procedure 40EP-9EO10, "Standard Appendices," Revision 32. Appendix 10 states, in part:

1. Request that Radiation Protection accompany the operator performing the local operations to perform area surveys.

2. **IF** it is desired to align Charging Pump(s) suction to the RWT, **THEN** perform the following:

   a. Place the appropriate Charging Pump(s) in "PULL-TO-LOCK."

   b. Direct an operator to PERFORM Attachment 10-A, Aligning Charging Pump Suction to the RWT, for the appropriate Charging Pump(s).

   c. **WHEN** the appropriate Charging Pump(s) has been aligned, **THEN** start the appropriate Charging Pump(s) as necessary.

Attachment 10-A states, in part:

1. Open CHB-V327, "RWT TO CHARGING PUMPS SUCTION" (70 ft. East Mechanical Piping Penetration Room). . .

4. **IF** aligning Charging Pump E, **THEN** perform the following (Charging Pump E VlvGallery)

a. Close CHE-V322, ""E" CHARGING PUMP CHE-P01 SUCTION ISOLATION VALVE".

b. Open CHE-V757, ""E" CHARGING PUMP ALTERNATE SUCTION ISOLATION VALVE".

5. Inform the responsible operator that the appropriate Charging Pump(s) are aligned to the RWT.

The team found that the auxiliary operator did not implement Appendix 10, Step 1 of emergency operating Procedure 40EP-9EO10. Instead of requesting a radiation protection person to accompany him, the operator went to the radiologically controlled area access to perform a routine entry. However, because of the loss of offsite power, the access computers were not functioning and routine entry data was being entered manually. The auxiliary operator failed to inform the radiation protection person of the necessity of his entry nor of the procedural requirement for a radiation protection person to accompany him. This is identified as the second example of Unresolved Item 05000529/2004012-XXX. Licensee personnel initiated CRDR 2716806 to evaluate the delay at the access point.

After reaching the valves, the auxiliary operator, with the procedure on the wrong page, proceeded to perform Attachment 10-A, Steps 4 and 5. After positioning the valves listed in Step 4, the auxiliary operator informed the control room operator that the charging Pump CHE-P01 suction had been transferred. The control room operator then started charging Pump CHE-P01 at approximately 08:05 am and secured charging Pump CHB-P01 at approximately 08:05:52 am. At approximately 08:05:59, charging Pump CHE-P01 tripped on low suction pressure, resulting in a loss of all charging flow.

At approximately 08:06:22, the control room operator re-started charging Pump CHB-P01. The team found that the control room operator was unaware that this pump was operating with the suction from the volume control tank. After approximately 4.5 minutes, the control room operator noticed that the volume control tank level had dropped to approximately 10 percent. At that time, the operator secured charging Pump CHB-P01 to prevent it from tripping on low suction pressure of becoming air-bound.

At approximately 08:11:31 am, the charging pump suction was properly transferred to the refueling water tank and charging Pump CHB-P01 was restarted. At approximately 11:32:37 am, the time line indicated that charging Pump CHA-P01 was started.

The team found that the auxiliary operator did not properly implement emergency operating Procedure 40EP-9EO10 as required. This is identified as the third example of Unresolved Item 05000529/2004012-XXX. Licensee personnel initiated CRDR 2716521 to evaluate the human performance error.

The team found that the failure to properly implement the emergency operating procedures, as written, complicated the recovery from the loss-of-offsite-power by

distracting the operators. The actual significance will be assessed during closure of Unresolved Item 05000529/2004012-XXX. This item has potential human performance and problem identification and resolution aspects.

3.2 Technical Support Center Emergency Diesel Generator Trip

a. Inspection Scope

The team interviewed members of the licensee's emergency planning organization and electrical maintenance department and reviewed security department logs to determine the cause of the failure of the technical support center diesel generator during the loss of off-site power. The team walked down the technical support center electrical distribution system and the technical support center diesel generator. The team reviewed the licensee's preliminary findings attached to CRDR 2715749 written to investigate and determine the root causes for the emergency planning problems arising from the loss of off-site power and plant trip on June 14, 2004.

b. Observations and Findings

The team found that the apparent cause for the failure of the technical support diesel generator to restore power to the technical support center was a human performance error during post maintenance testing of the diesel engine starting system on June 8, 2004.

On June 14, 2004, as a result of the loss of off-site power, electrical power was lost to the technical support center. As designed, the technical support center diesel generator started, but it did not re-energize the technical support center electrical loads. Electrical maintenance technicians were called to investigate the problem and shortly after they arrived at the technical support center diesel generator the diesel engine tripped. The engine control panel alarms indicated that the trip was due to high engine temperature. Electrical power was restored to the technical support center when off-site power was restored to Unit 1 at 9:10 AM. The technical support center was without electrical power for approximately 1 hour 30 minutes.

During subsequent troubleshooting, electrical maintenance technicians determined that the engine operating switch was in "Idle." With the switch in "Idle," the diesel generator started on loss of electrical power to the technical support center, but did not come up to proper voltage and frequency and did not re-energize the technical support center electrical distribution panel. As a result, the engine radiator cooling fan did not start, so the engine overheated and tripped on high temperature. The electrical maintenance technicians returned the engine operating switch to its normal "Run" position and wrote CRDR 2715726.

The licensee determined that the engine operating switch was apparently left in the "Idle" position after post maintenance testing of the engine starting system performed on June 8, 2004 under work Order 2623863. During this monthly engine starting battery inspection, electricians noted that one battery terminal and connector were corroded. The electricians contacted their team leader and received permission to cleanup the connection using the same work order. The team leader and the lead electrician determined that the starting system needed to be tested after the battery was returned

to its normal configuration. The lead electrician suggested using a portion of preventative maintenance task, "Quarterly Restrike Test for TSC Diesel Generator." Since this test is routinely performed by the electricians working on the starting battery, the team leader allowed the electricians to perform the test without a working copy of the test procedure in the field. After the diesel generator was successfully started, the engine operating switch was moved from "Run" to "Idle" to let the engine run at a slower speed and cooldown before being secured. The team determined that the failure to have a working copy of the test procedure at the engine during this post maintenance testing and failure to use the restoration guidance contained in the test procedure contributed directly to the failure to restore the technical support center diesel generator to its normal standby condition.

On June 16, 2004 The licensee performed the periodic one hour loaded test run of the technical support center diesel generator using preventative maintenance task, "Quarterly Restrike Test for TSC Diesel Generator," under work Order 2715869. The diesel generator started as expected and automatically energized the technical support center electrical power distribution panel. The diesel generator ran loaded for one hour with no problems noted. The diesel generator was shutdown using the task instructions and restoration directions.

The team determined that the diesel generator failure contributed to the delay in staffing the technical support center. As a result of diesel generator failure, the responding members of the emergency response organization were moved to the satellite technical support center adjacent to the Unit 2 control room. However, normal off-site power was restored to the technical support center before the two hour staffing requirement of PVNGS Emergency Plan, Table 1, "Minimum Staffing Requirements for PVNGS for Nuclear Power Plant Emergencies," Revision 28.

Unresolved Item 05000529/2004012-XXX is opened to evaluate the corrective actions and apparent cause determination associated with the technical support center diesel generator failure. This item has potential human performance error aspects.

3.3 Emergency Response Organization Issues

a. Inspection Scope

The team interviewed members of the licensee's emergency planning organization and security department and reviewed security department logs and emergency planning records to determine the cause of the multiple emergency response organization communication problems during the loss of off-site power. The team also reviewed the licensee's preliminary findings attached to significant CRDR 2715749 initiated to investigate and determine the root causes for the emergency planning problems arising from the loss of off-site power and plant trip on June 14, 2004 and attended the significant event investigation team meetings.

b. Observations and Findings

The team found that the apparent causes for the multiple emergency response organization communication problems were (1) the unanticipated loss of off-site power to all three units which resulted in the loss of normal emergency planning

communications equipment, and (2) human performance errors in implementing EPIP-01, "Satellite Technical Support Center Actions," Revision 14.

When the loss of off-site power and three unit trip occurred the two of the unit shift managers, the on-site manager and the operations manager, who was the on-call technical support center emergency coordinator, were in the plan of the day meeting in the operations support building adjacent to the Unit 2 control room. The Unit 1 shift manager returned to the Unit 1 control room and assumed the duties as emergency coordinator for all three units. When the on-site manager arrived at the Unit 1 control room to relieve the shift manager of his emergency coordinator responsibilities, Unit 2 entered an Alert emergency action level, so the on-site manager returned to Unit 2 to set up the satellite technical support center ant the most affected unit. The Unit 1 shift manager had declared a Notification of Unusual Event for the loss of off-site power for greater than 15 minutes. He gave this information to the on-site manager to coordinate the emergency notification to state and local authorities.

The Unit 2 shift manager declared an Alert emergency action level based on the loss of off-site power concurrent with a loss of one of the Unit 2 emergency diesel generators for greater than 15 minutes. He directed the on-shift emergency communicator to notify state and local authorities. The emergency communicator immediately determined that the normal notification alert network system was not working and used the backup radio notification system to notify the state and local authorities within 8 minutes of the Alert classification.

When the on-site manager arrived at the Unit 2 satellite technical support center in the Unit 2 control room, he was told by the operations manager that unit 2 had assumed all emergency communications, but did not question him as to whether or not the Unit 1 Notification of Unusual Event notification was sent out to the state and local authorities. The team determined that there was no formal turnover on emergency communications responsibilities from the Unit 1 shift manager to the Unit 2 shift manager or the on-site manager who was going to relieve the Unit 2 shift manager of emergency coordinator responsibilities. In addition, the on-site manager and operations manager did not effectively communicate the status of off-site notification. These two incomplete communications human performance errors that resulted in the Unit 1 Notification of Unusual Event not being sent to state and local authorities.

The Unit 3 shift manager declared a Notification of Unusual Event for the loss of off-site power for greater than 15 minutes. There was a time delay before the Unit 3 on-shift emergency communicator attempted to send out the notification using the normal notification alert network system. When he determined that it was not working he used the backup radio notification system but did not notify the state and local authorities until 20 minutes after the Notification of Unusual Event classification. The team determined that the delay in starting the notification process and the need to use the backup radio system were human performance errors that delayed the Unit 3 Notification of Unusual Event beyond the 15 minute requirement in EPIP-01, "Satellite Technical Support Center Actions," Revision 14.

The team determined that loss of power to the normal notification alert network system did complicate the emergency notification of state and local authorities. In addition the licensee determined that the three satellite technical support center dose projection

computers. The apparent cause for both failures was that both systems were supplied electrical power from electrical circuits that have no backup power supplies. CRDR 2715749 addresses the loss of power to the normal notification alert network system and CRDR 2716281 addresses the dose projection computers. The recommended corrective action is provide an uninterruptible power supply for both systems.

During the initial loss of off-site power and failure of one Unit 2 emergency diesel generator the Unit 2 shift manager and on-shift emergency communicator were delayed in sending out the emergency pager notification to the on-call emergency response organization. The team determined that the delay of 16 minutes contributed to the greater than 2 hour response time of the on-call technical support electrical engineer to the technical support center. The problems with protected area access (See Report Section X.X.) did not interfere with this failure to meet the minimum staffing requirements of PVNGS Emergency Plan Table 1. The Unit 2 mistakenly N/A'd the EPIP-01 step to activated the backup dialogic auto-dialer system for emergency response organization notification. During interviews the Unit 2 stated that he thought that June 14 a Monday ws a normal working day and the emergency response organization would respond to the plant wide announce of the Alert classification. The team determined that this human performance error contributed to the late staffing of the technical support center and the less than minimum required number of radiation protection technicians reporting to the operations support center within the required 2 hours. This failure to use EPIP-01 properly was documented in CRDR 2715749 and the licencee revised EPIP-01, to always activate the dialogic auto-dialer for backup emergency response organization notification.

Unresolved Item 05000529/2004012-XXX is opened to evaluate the corrective actions and root cause determination associated with the delayed Unit 3 and missed Unit 1 notifications of state and local officials of their notification of unusual events. This item has potential problem human performance error aspects.

Unresolved Item 05000529/2004012-XXX is opened to evaluate the corrective actions and root cause determination associated with the inoperability of the radiological dose projection computers used to provide radiologically based protective action recommendations to state and local authorities.

Unresolved Item 05000529/2004012-XXX is opened to evaluate the corrective actions and apparent cause determination associated with the delay in notifying the on-call emergency response organization. This item has potential problem human performance error aspects.

4.0 Coordination with Off-site Electrical Organizations

a. Inspection Scope

The team reviewed the design and maintenance practices off site electrical organization in order to assess factors that influenced electrical power Grid failure, the extend of the system failure and the corrective actions for preventing such failures.

b. Observations and Findings

The loss of the Palo Verde 500kV grid, which disabled all the seven offsite power supplies for the nuclear stations, was due to the cascading effect of a wide area electrical isolation that originated from an electrical fault on a 230kV transmission line that remained un isolated for a period of 39 Sec., The selective tripping of the breakers to isolate problems at the West Wing 230Kv Substation, near the source of the fault, did not perform as required due to a relay failure and a design deficiency

The switchgear maintenance at the Palo Verde 500kV substation is performed by Salt River Project (SRP). The breakers undergo a yearly maintenance including a check of the SF6 tubing, pressure switches; a check of the air system for alarms and the operation of the compressor; breaker timing and operational check of the mechanisms.

The protective relaying is also inspected yearly. The relays' settings, software and firmware, operating characteristics, and communication circuits are verified for accuracy. The Palo Verde substation is manned by maintenance personnel during normal working hours for prompt identification of any evolving problems.

The licensee has calculated the onsite requirement for electrical voltage to be 512kV. They have directed the APS Energy Control Center (APS-ECC), the local transmission system operator, to provide voltage range of 525 to 535kV for the Palo Verde 500kV Substation. The Energy Control Center continued to provide voltage at the expected voltage band following the isolation of the fault.

The team concluded that the remedial measures taken and planned by the offsite electrical organizations would be an enhancement for preventing a cascading blackout in the Palo Verde 500kV substation.

5.0 Risk Significance of the Event

6.0 Assessment of Event Response

7.0 Exit Meeting Summary

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

Dennis W. Gerlach, Manager, Transmission & generation Operations, SRP
Mike gentry, Manager, Grid Operations-PDO, Transmission and Generation Dispatching, SRP
Giang Vuong, Protection Engineer, SRP
Edmundo, Marquez, Manager System Protection, Electronic Systems, SRP
Cary B. Deise, Director, Transmission Planning and Operations, APS
Tom Glock, Power Operations Manager, Power Ops Tech Services, APS
Steven Phegley, Section Leader, Protection Metering, & Automated Control, APS
Steven Kestler, Electrical Engineer, Palo Verde Nuclear Station
Bajranga Aggarwal, Systems Engineer, APS

NRC

ITEMS OPENED, CLOSED, AND DISCUSSED

05000528/2004-012;
05000529/2004-012;
05000530/2004-012

DOCUMENTS REVIEWED

Drawings

NUMBER	TITLE	REVISION
01-J-SPL-003	Control Logic Diagram Essential Spray Pond Auviliary Pumps, Day Tk Valve & Alarms	3

Drawings

NUMBER	TITLE	REVISION
01-J-EWL-001	Control Logic Diagram Essential Cooling Water Pumps and Surge Tank Fill Valves	2
01-J-EWL-002	Control Logic Diagram Essential Cooling Water Loop A X-Tie Valves & System Alarms	0
01-J-SPL-001	Control Logic Diagram Essential Spray Pond Pumps	3
01-M-EWP-001	P&I Diagram Essential Cooling Water System	29
01-M-SPP-001	P&I Diagram Essential Spray Pond System Sheet 1 of 3	35
01-M-SPP-001	P&I Diagram Essential Spray Pond System Sheet 2 of 3	35
01-M-SPP-001	P&I Diagram Essential Spray Pond System Sheet 3 of 3	35
01-M-SPP-002	P&I Diagram Essential Spray Pond System	12

Miscellaneous Documents:

NUMBER	TITLE	REVISION
	Palo Verde Nuclear Generating Station Design Basis Manual, EW System	16
	Palo Verde Nuclear Generating Station Design Basis Manual, SP System	13
	PV Unit 2 Archived Operator Log 06/14/2004, 12:10:47 AM, through 06/15/2004, 11:10:30 PM	
Bulletin 74-09	Deficiency in General Electric Model 4KV Magne-Blast Breakers	August 6, 1974
Information Notice 84-29	General Electric Magne-Blast Circuit Breaker Problems	April 17, 1984
Information Notice 90-41	Potential Failure of General Electric Magne-Blast Circuit Breakers and AK Circuit Breakers	June 12, 1990
Information Notice 93-26	Grease Solidification Causes Molded Case Circuit Breaker Failure To Close	April 7, 1993

Miscellaneous Documents:

NUMBER	TITLE	REVISION
Information Notice 93-91	Misadjustment Between General Electric 4.16-KV Circuit Breakers and Their Associated Cubicles	December 3, 1993
Information Notice 94-02	Inoperability of General Electric Magne-Blast Breaker Because of Misalignment of Close-Latch Spring	January 7, 1994
Information Notice 94-54	Failures of General Electric Magne-Blast Circuit Breakers To Latch Closed	August 1, 1994
Information Notice 95-22	Hardened or Contaminated Lubricants Cause Metal-Clad Circuit Breaker Failure	April 21, 1995
Information Notice 96-43	Failures of General Electric Magne-Blast Circuit Breakers	August 12, 1996

Procedures:

NUMBER	TITLE	REVISION
40EP-9EO07	Loss of Offsite Power/Loss of Forced Circulation	10
40EP-9EO10	Standard Appendices	33
40OP-9CH01	CVCS Normal Operations	35

CRDR 2715749
Security Access Transaction Records for June 14, 2004
Day Shift Security Department Logs for June 14, 2004
Security Computer Alarm logs for June 14, 2004
20SP-OSK08, "Compensatory Measures for the Loss of Security Equipment Effectiveness, Revision 27
21SP-OSK11, "Security Contingencies," Revision 13
20DP-OSK29, "Security System Testing," Revision 27

CRDR 2715669
CRDR 2715749
Sally Port Vehicle Barrier Operating Instructions, as posted on June 14, 2004
Sally Port Vehicle Barrier Operating Instructions, revised on June 17, 2004
Day Shift Security Department Logs for June 14, 2004

Palo Verde AIT June 13-
Prepared by George Skinner

Documents Reviewed

SRP Drawings

A-774-10.110, Palo Verde Station 500KV Switchyard PL912 Closing and Tripping Schematic, Revision 0

A774-10.111/1, Palo Verde Station 500KV Switchyard 500KV Breaker PL912 Schematic Diagram, Revision 0

A774-10.112, Palo Verde Station 500KV Switchyard PL912 Fail/Fault and CT Fail/Fault Schematic Diagram, Revision 0

A774-10.113, Palo Verde Station 500KV Switchyard PL915 Fail/Fault and CT Fault Schematic Diagram, Revision 0

A-774-10.13, Palo Verde Station 500KV Switchyard 500KV Breaker PL932 Closing and Tripping Schematic Diagram, Revision 9

A-774-10.14, Palo Verde Station 500KV Switchyard 500KV Switchyard 500KV Breaker Failure & Fault Monitor PL992 & PL995 Schematic Diagram, Revision 9

A-774-10.15, Palo Verde Station 500KV Switchyard 500KV Breaker PL915 Closing and Tripping Schematic Diagram, Revision 12

A-774-10.20, Palo Verde Station 500kV Switchyard 500kV Breaker PL 942 Closing & Tripping Schematic Diagram, Revision 10

A-774-10.21, Palo Verde Station 500kV Switchyard 500kV Breaker PL 945 Closing & Tripping Schematic Diagram, Revision 10

A-774-10.36, Palo Verde Station 500KV Switchyard 500KV Breaker PL915 Schematic Diagram, Revision 6

A-774-10.42, Palo Verde Station 500KV Switchyard 500KV Breaker PL 945 Schematic Diagram, Revision 10

A-774-10.49, Palo Verde Station 500KV Switchyard 500KV Breaker PL935 Closing and Tripping Schematic Diagram, Revision 7

A-774-10.5, Palo Verde Station 500KV Switchyard Devers Line Relaying Schematic Diagram, Revision 5

A-774-10.50, Palo Verde Station 500KV Switchyard 500KV Breaker PL938 Closing and Tripping Schematic Diagram, Revision 7

A-774-10.82, Palo Verde Station 500KV Switchyard PL972 Closing and Tripping Schematic Diagram, Revision 1

A-774-10.86, Palo Verde Station 500KV Switchyard PL975 Closing and Tripping Schematic Diagram, Revision 1

A-774-10.90, Palo Verde 500KV Switchyard 500KV Hassayampa #1 Line Rel 87La Schematic Diagram, Revision 3

A-774-10.91, Palo Verde 500KV Switchyard 500KV Hassayampa #1 Line Rel 87La Schematic Diagram, Revision 2

A-774-20.3, Palo Verde Substation Westwing #1 500KV Line Relaying21La Schematic Diagram Sheet 1, Revision 1

A-774-20.4, Palo Verde Substation Westwing #1 500KV Line Relaying21La Schematic Diagram Sheet 2, Revision 1

A-774-20.6, Palo Verde Substation Westwing #1 500KV Line Relaying21Lb Schematic Diagram Sheet 1, Revision 1

A-774-20.7, Palo Verde Substation Westwing #1 500KV Line Relaying21Lb Schematic Diagram Sheet 2, Revision 1

A-774-20.9, Palo Verde Substation Westwing #1 500KV Line Relaying 87Lc Schematic Diagram Sheet 2, Revision 1

A-774-8.2, Palo Verde 500KV SWYD. One Line Diagram SH2 Bays 1 & 2 IN-6W, Revision 12
A-774-8.3, Palo Verde Station 500kV Switchyard IN-6W 500KV Bays 3 & 4 One Line Diagram Sh.3, Revision 14

K-774-9.1, Palo Verde Substation Bay 1 Three Line Diagram, Revision 11

K-774-9.3, Palo Verde Station 500KV Switchyard Bay 3 Three Line Diagram, Revision 12

K-774-9.4, Palo Verde Substation 500KV Switchyard Bay 4 Three Line Diagram, Revision 18

K-774-9.6, Palo Verde Station 500KV Switchyard Bay 7 Three Line Diagram, Revision 1

APS Drawings

G-33417 Sheet 1 of 2, Westwing 230KV Switchyard USBR Liberty & Pinn Pk Line Relaying CT/PT Schematic, Revision 12

G-33417 Sheet 2 of 2, Westwing 230KV Switchyard WAPA 230KV Liberty & Pinn Pk Line Relaying CT-PT Schematic, Revision 12

G-33434 Sheet 1 of 1, Westwing 230KV Switchyard WAPA 230KV Liberty Line Relaying DC Schematic, Revision 9

G-33451, Westwing 230KV Switchyard WAPA 230KV Liberty Line & West Bus Tie PCB WW1022 DC Schematic, Revision 14 (with red line revision)

G-33453 Sheet 1 of 1, Westwing 230KV Switchyard WAPA 230KV Liberty & Pinn Pk Line PCB WW1126 Schematic, Revision 16 (with red line revision)

G-33493 Sheet 1 of 2, Westwing 230KV Switchyard USBR Liberty & Pinn Pk Line CCPD Jct. Box Wiring Diagram, Revision 1

PVNGS Drawings

01-E-MAB-001, Elementary Diagram Main Generation System Main Generator Three Line Metering and Relaying, Revision 13

01-E-MAB-0012, Elementary Diagram Main Generator System Main Generator Three Line Metering and Relaying, Revision 9

01-E-MAB-004, Elementary Diagram Main Generation System Main Transformer Three Line Diff, Metering and Relaying, Revision 8

01-E-MAB-006, Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping, Revision 3

01-E-MAB-007, Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping, Revision 5

01-E-MAB-008, Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping, Revision 5

01-E-MAB-009, Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping, Revision 4

01-E-MAB-010, Elementary Diagram Main Generation System Generator & Transformer Back-up Protection Unit Tripping, Revision 8

01-E-MAB-011, Elementary Diagram Main Generation System Generator & Transformer Back-up Protection Unt Tripping, Revision 7

01-E-MAB-011, Elementary Diagram Main Generation System Generator & Transformer Back-up Protection Unit Tripping, Revision 12

01-E-MAB-013, Elementary Diagram Main Generation System Generator & Transformer Unit Tripping Cabling Block Diagram, Revision 10

01-E-NHA-001, Single Line Diagram 480V Non-Class 1E Power System Motor Control Center 1E-NHN-M13, Revision 21

01-E-NHA-010, Single Line Diagram 480V Non-Class 1E Power System Motor Control Center 1E-NHN-M10, Revision 19

01-E-NNA-001, Single Line Diagram 120V AC Non-Class 1E Ungrounded Instrument and Control Panel 1E-NNN-D11, Revision 19

01-E-NNA-002, Single Line Diagram 120V AC Non-Class 1E Ungrounded Instrument and Control Panel 1E-NNN-D12, Revision 19

01-E-PHA-001, Single Line Diagram 480V Class 1E Power System Motor Control Center 1E-PHA-M31, Revision 16

01-E-PHA-002, Single Line Diagram 480V Class 1E Power System Motor Control Center 1E-PHB-M32, Revision 16

13-E-MAA-001, Main Single Line Diagram, Revision 21

G-32900 Sheet 1 of 2, Westwing 500KV Switchyard Bays 1 - 9 One Line Diagram, Revision 23

G-32900 Sheet 2 of 2, Westwing 500KV Switchyard Bays 10 - 18 One Line Diagram, Revision 12

G-32901 Sheet 1 of 2, Westwing 500KV Switchyard Transformer Bays 1 & 4 One Line Diagram, Revision 28

G-32901 Sheet 2 of 2, Westwing 500KV Switchyard Bays 7, 10, 13 & 16 One Line Diagram, Revision 10

G-33300, Westwing 230KV Switchyard Bays 1-9 One Line Diagram, Revision 25

G-33301 Sheet 1 of 2, Westwing 230KV Switchyard Bays 10-18 One Line Diagram, Revision 31

G-33301 Sheet 2 of 2, Westwing 230KV Switchyard Bays 19-27 One Line Diagram, Revision 2

Un-numbered Sketch, Palo Verde Transmission System Sheet 1, undated

Un-numbered Sketch, Palo Verde Transmission System Sheet 2, undated

<u>Miscellaneous</u>

APS Letter Robert Smith to N. Bruce et al., Final Report for the 2002 Palo Verde /Hassayampa Operating Study, dated June 5, 2002

2003-04 Winter Palo Verde Unit 2 Uprating Net Generating Capacity of 1408MW for Updated Final Safety Analysis Report (UFSAR), dated November 2003

Procedure No. PVTS-01, Palo Verde Transmission System Interchange Scheduling and Congestion Management Procedure, Revision 8

PVNGS Technical Specifications, Through Amendment No. 150, dated November 21, 2003, Corrected December 12, 2003

APS Letter 102-04310-WEI/SAB/RKR, Response to NRC Request for Additional Information Regarding Proposed Amendment to Technical Specifications (TS) 3.8.1, AC Sources-Operating and 3.3.7, Diesel Generator (DG)-Loass of Voltage Start (LOVS), dated July 16, 1999

NRC Letter M Fields to G. Overbeck APS, Palo Verde Nuclear Generating Station Units 1, 2 and 3 – Issuance of Amendments Re: Changes Related to Double Sequencing and Degraded Voltage Instrumentation (TAC Nos. MA4406, MA4407, and MA4408)

10CFR50.59 Evaluations

Revise the UFSAR, Technical Specifications, and Technical Specifications Bases to enhance the means of complying with the requirements of Regulatory Guide 1.93 for offsite power source, Revision 0

10CFR 50.59 Screening and Evaluation S-04-0009, Updated Transmission Grid Stability Study: Salt River Project 20031126 (LDCR 2003F040), Revision 0

ATTACHMENT 2

AUGMENTED INSPECTION TEAM CHARTER

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

June 15, 2004

MEMORANDUM TO: Anthony T. Gody, Chief
Operations Branch
Division of Reactor Safety

FROM: Bruce Mallett, Regional Administrator /RA/

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER; PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3, COMPLETE LOSS OF OFFSITE POWER AND MULTIPLE MITIGATING SYSTEM FAILURES

In response to the complete loss of all offsite power sources, the trip of all three units, and the Unit 2 Emergency Diesel Generator "A," failing to function as required at Palo Verde Nuclear Generating Station on June 14, 2004, an Augmented Inspection Team is being chartered. There was no impact to public heath and safety associated with the event. You are hereby designated as the Augmented Inspection Team (AIT) leader.

A. Basis

On June 14, 2004, at 9:45 a.m. CDT, all offsite power supplies to the Palo Verde Nuclear Generating Station were disrupted, with a concurrent trip of all three units. Additionally, the Unit 2 Emergency Diesel Generator "A" failed to function as required. As a result, the licensee declared a Notice of Unusual Event (NOUE) for all three units at about 9:50 a.m. CDT and elevated to an Alert for Unit 2 at 9:54 CDT. The licensee and NRC resident inspectors also reported a number of other problems, including the failure of Unit 2 Charging Pump "E," the failure of a Unit 3 steam bypass control valve, multiple breakers failing to operate during recovery operations, and emergency response facility and security interface issues which may have impeded emergency responders. This event meets the criteria of Management Directive 8.3 for a detailed follow up inspection, in that, it involved multiple failures to systems used to mitigate an actual event. The initial risk assessment, though subject to some uncertainties, indicates that the conditional core damage probability was in the range of high E-4. Because the initial risk assessment was in the range for consideration of an AIT and because of multiple failures in systems used to mitigate an actual event, it was decided that an AIT is the appropriate NRC response for this event.

The AIT is being dispatched to obtain a better understanding of the event and to assess the responses of plant equipment and the licensee to the event. The team is also tasked with reviewing the licensee's root-cause analyses.

B. Scope

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

1. Develop a complete sequence of events related to the loss-of-offsite power, the multiple unit trips, and the Unit 2 emergency diesel generator failure.

2. Assess the performance of plant systems in response to the event, including any design considerations that may have contributed to the event.

3. Assess the adequacy of plant procedures used in response to the event.

4. Assess the licensee's response to the event, including operator actions and emergency declarations, and any emergency response facility or security interface issues that may have adversely affected response to the event.

5. Assess the licensee's determination of the root and/or apparent causes of offsite power loss, emergency diesel generator failure, and other mitigating system(s) failures.

6. Based upon the licensee's cause determinations, review any maintenance related actions which could have contributed to the event initiation or produced subsequent response problems.

7. Review the licensee's assessment of coordination activities with off-site electrical dispatch organizations prior to and during the event.

8. Provide input to the regional Senior Reactor Analyst for further assessment of risk significance of the event.

C. Guidance

The Team will report to the site, conduct an entrance meeting, and begin inspection no later than June 16, 2004. A report documenting the results of the inspection should be issued within 30 days of the completion of the inspection. While the team is on site, you will provide daily status briefings to Region IV management. The team is to emphasize fact-finding in its review of the circumstances surrounding the event, and it is not the responsibility of the team to examine the regulatory process. The team should notify Region IV management of any potential generic issues identified related to this event for discussion with the Program Office. Safety concerns that are not directly related to this event should be reported to the Region IV office for appropriate action.

For the period of the inspection, and until the completion of documentation, you will report to the Regional Administrator. For day to day interface you will contact Dwight Chamberlain, Director, Division of Reactor Safety. The guidance in Inspection Procedure 93800, "Augmented Inspection Team," and Management Directive 8.3, "NRC Incident Investigation Procedures," apply to your inspection. This Charter may be modified should the team develop significant new information that warrants review. If you have any questions regarding this Charter, contact Dwight Chamberlain at (817) 860-8180.

Distribution:
B. Mallett
T. Gwynn
J. Dixon-Herrity
J. Dyer
R. Wessman
T. Reis
H. Berkow
S. Dembeck
M. Fields
D. Chamberlain
A. Howell
C. Marschall
T. Pruett
J. Clark
V. Dricks
W. Maier
N. Salgado
G. Warnick
J. Melfi

<u>ATTACHMENT 3</u>
Sequence of Events

Electrical Sequence of Events

07:40:55.747	Fault #1 inception Fault #1 type = C-N Fault #1 cause/location = Phase down (broken bells) reported near 115th Ave. & Union Hills (WW-LBX Line) At Westwing, the Liberty line relays operated properly and issued a trip signal. Incorporated in this scheme is a Westinghouse high-speed "AR" auxiliary tripping relay that is used to "multiply" that trip signal toward both trip coils of two breakers (WW1022 & WW1126). The "AR" relay failed (partially) and issued the trip signal to breaker WW1126 only. Since the trip signal was never successfully issued to WW1022, breaker failure for WW1022 was also never initiated (this would have cleared the Westwing 230kV West bus and isolated the fault). Therefore, the "remote" ends of all lines feeding into the 525kV and 230kV yards were required to trip to isolate the fault.
07:40:55.814	4.0 cycles after fault #1 inception WW1126 opened (LBX / PPX 230kV crossover breaker)
07:40:55.822	4.5 cycles after fault #1 inception LBX1282 opened (Westwing 230kV Line)
07:40:56.115	22.1 cycles after fault #1 inception AFX732 & AFX735 opened (Westwing 230kV Line)
07:40:56.122	22.5 cycles after fault #1 inception YP452 & YP852 opened (Westwing 525kV Line)
07:40:56.136	23.3 cycles after fault #1 inception WW1426 & WW1522 opened (Agua Fria 230kV Line)
07:40:56.142	23.7 cycles after fault #1 inception WW856 & WW952 opened (Yavapai 525kV Line)
07:40:56.165	25.1 cycles after fault #1 inception DV322 & DV722 & DV962 opened (Westwing 230kV Line)
07:40:56.172	25.5 cycles after fault #1 inception WW1726 & WW1822 opened (Deer Valley 230kV Line)
07:40:56.196	26.9 cycles after fault #1 inception RWYX482 & RWYX582 & RWYX782 opened (Westwing 230kV Line) (Waddell 230kV Line) (230/69kV Transformer #8)

ATTACHMENT 3
Sequence of Events

Electrical Sequence of Events

07:40:56.515	46.1 cycles after fault #1 inception WW1222 opened (Pinnacle Peak 230kV Line)
t = unknown	Surprise Lockout "L" operated (230/69kV Transformer #4 Differential & B/U Over-Current)
07:40:56.548	48.1 cycles after fault #1 inception SC622 & SC922 & SC262 opened (Surprise 230/69kV Transformer #4)
07:40:57.549	108.1 cycles after fault #1 inception SC1322 opened (Westwing 230kV Line)
07:40:57.800	123.2 cycles after fault #1 inception RWP-CT2A opened (Redhawk Combustion Turbine 2A)
07:40:57.807	123.6 cycles after fault #1 inception RWP-ST1 opened (Redhawk Steam Turbine 1)
07:40:57.814	124.0 cycles after fault #1 inception RWP-CT1A opened (Redhawk Combustion Turbine 1A)
07:40:58.339	155.5 cycles after fault #1 inception RIV762 opened (Westwing 69kV Line)
07:40:58.372	157.5 cycles after fault #1 inception HH762 opened (Westwing 69kV Line)
t = unknown	Westwing Lockout "AK" operated (230/69kV Transformer #11 Differential & B/U Over-Current)
07:40:59 (EMS)	WW2026 & WW2122 opened (Westwing 230/69kV Transformer #11 - High Side)
07:40:59.272	211.5 cycles after fault #1 inception WK362 opened (Westwing 69kV Line)
07:40:59.489	224.5 cycles after fault #1 inception HAAX935 & HAAX938 opened (Hassayampa - Arlington 525kV Line) (Time stamp provided by SRP)
07:41:00 (EMS)	WW862 & WW962 & WW1362 opened (Westwing 230/69kV Transformer #11 - Low Side)
07:41:00.392	278.7 cycles after fault #1 inception WW752 opened (South 345kV Line)
07:41:01.982	Fault #1 type changed = B-C-N

ATTACHMENT 3

Sequence of Events

Electrical Sequence of Events

07:41:02.144	383.8 cycles after fault #1 inception PSX832 closed auto (Perkins Cap-Bank Bypass) (Time stamp provided by SRP)
07:41:02.154	Fault #1 type changed = C-N
07:41:02.799	Fault #1 type changed = B-C-N
07:41:03.966	493.1 cycles after fault #1 inception SC562 opened (McMicken 69kV Line)
07:41:05.373	577.6 cycles after fault #1 inception MQ562 opened (McMicken 69kV Line)
07:41:07.849	12.102 seconds after fault #1 inception HAAX922 & HAAX925 opened (Palo Verde 525kV Line #2) (Time stamp provided by SRP)
07:41:07.851	12.104 seconds after fault #1 inception PLX972 & PLX975 opened (Hassayampa 525kV Line #2) (Time stamp provided by SRP)
07:41:07.859	12.112 seconds after fault #1 inception HAAX932 opened (Palo Verde 525kV Line #1) (Time stamp provided by SRP)
07:41:07.875	12.128 seconds after fault #1 inception PLX982 & PLX985 opened (Hassayampa 525kV Line #3) (Time stamp provided by SRP)
07:41:07.878	12.131 seconds after fault #1 inception HAAX912 & HAAX915 opened (Palo Verde 525kV Line #3) (Time stamp provided by SRP)
07:41:07.880	12.133 seconds after fault #1 inception PLX942 & PLX945 opened (Hassayampa 525kV Line #1) (Time stamp provided by SRP)
07:41:08.104	Fault #1 type changed = A-B-C-N
07:41:10.445	14.698 seconds after fault #1 inception NV1052 & NV1156 opened (Westwing 525kV Line)
07:41:10.456	14.709 seconds after fault #1 inception WW556 & WW652 opened (Navajo 525kV Line)
07:41:12 (EMS)	WW424J opened (Westwing 230kV West Bus Reactor)

ATTACHMENT 3

Sequence of Events

Electrical Sequence of Events

07:41:20.005	24.258 seconds after fault #1 inception PLX992 opened (Devers 525kV Line) (PLX995 out-of-service at this time) (Time stamp provided by SRP)
07:41:20.113	24.366 seconds after fault #1 inception PLX932 & PLX935 opened (Rudd 525kV Line) (Time stamp provided by SRP)
07:41:20.145	24.398 seconds after fault #1 inception RUX912 & RUX915 opened (Palo Verde 525kV Line) (Time stamp provided by SRP)
07:41:20.864	25.117 seconds after fault #1 inception PLX912 & PLX915 opened (Westwing 525kV Line #1) (Time stamp provided by SRP)
07:41:20.873	25.126 seconds after fault #1 inception WW1456 & WW1552 opened (Palo Verde 525kV Line #2)
07:41:20.874	25.127 seconds after fault #1 inception WW1156 & WW1252 opened (Palo Verde 525kV Line #1)
07:41:20.895	25.148 seconds after fault #1 inception PLX922 & PLX925 opened (Westwing 525kV Line #2) (Time stamp provided by SRP)
07:41:23.848	28.101 seconds after fault #1 inception PLX988 opened (Palo Verde Unit-3) (Time stamp provided by SRP)
07:41:24.280	System Frequency = 59.514 Hz (Measured at APS Reach Substation)
07:41:24.641	28.894 seconds after fault #1 inception PLX918 opened (Palo Verde Unit-1) (Time stamp provided by SRP)
07:41:24.652	28.905 seconds after fault #1 inception PLX938 opened (Palo Verde Unit-2) (Time stamp provided by SRP)
07:41:25 (DOE)	ED4-122 & ED4-322 opened (DOE ED4 Substation) Tripped on under-frequency (Note frequency low at 07:41:24.280)
07:41:25 (EMS)	ML142, ML542, ML1042 & ML1442 opened (Moon Valley 12kV Feeders) Tripped on under-frequency (Note frequency low at 07:41:24.280)
07:41:28 (DOE)	MEX794 closed auto (Mead Cap Bank bypass)

ATTACHMENT 3
Sequence of Events

Electrical Sequence of Events

07:41:34.615	38.868 seconds after fault #1 inception MEX1092 & MEX1692 opened (Perkins - Westwing 525kV Line) Fault #1 cleared
07:42:22.773	System Frequency = 59.770 Hz (Measured at APS Reach Substation)

ATTACHMENT 3
Sequence of Events

Unit 1 Sequence of Events

0741 Startup Transformer# 2 Breaker 945 Open
Excessive Main Generator and Field Currents Noted
Engineered Safeguards Features Bus Undervoltage
Loss of Offsite Power Load Shed Train A and B
Emergency Diesel Generator Train A and B Start Signal
Fast Clsg of IV commanded (then rescinded in same second)
No ETSV pressure trip
Low Departure from Nucleate Boiling Ratio Reactor Trip
Master Turbine Trip
Main Turbine Mechanical Over Speed Trip
Emergency Diesel Generator "A" Operating (10 Second Start Time)
Emergency Diesel Generator "B" Operating (13 Second Start Time*)

0751 Manual Main Steam Isolation System Actuation

0758 Declared Notice of Unusual Event
(loss of essential power for greater than 15 minutes)

0810 Both Gas Turbine Generator Sets Started,
#1 GTG is supplying power to NAN S07

0813 Closed 525 k 552-942. The East bus is powered from Hass #1

0838 Restored power to Startup Transformer X01

0844 Restored power to Startup Transformer X03

0855 Fire reported in 120 ft Aux building. Fire brigade confirmed that no fire existed but paint was heated causing fumes. Later it was confirmed that fumes were caused by the elevated temperature of the letdown heat exchanger when it failed to isolate.

0900 HI Temp Abnormal Operation Porcedure entered for Letdown heat exchanger outlet temperature offscale high.

1002 Reset Generator Protective Trips (volts/hertz; Backup under-frequency)
Palo Verde Switchyard Ring Bus restored

1159 Paralleled DG B with bus and cooled down engine restoring the in house buses

1207 Emergency Coordinator terminated NUE for all three units

1248 Paralleled DG A with bus and cooled down

2209 Noted grid voltage greater than 535.5 volts Shift Manager Coordinated with ECC

6/15

<u>ATTACHMENT 3</u>
Sequence of Events

Unit 1 Sequence of Events

0005	Restored CVCS letdown per Std Appendix 12 started Chg Pump 'A'
0155	Established RCP seal injection and controlled bleed off
0241	Started 2A RCP, had to secure due to low running amps other two units had RCP's running (what were the amps at the time) exiting of EOP delayed due to switchyard conditions
0305	Exited Loss of Letdown AOP after restoration of letdown per Standard App. 12 of EOP's
0345	Palo Varde Switchyard E-W voltage at approx. 530.7 KV
0818	Started RCP's 2A and 1A
0920	Started RCP's 2B and 1B
0930	Exited EOP 40EP- 9E007 Loss of Offsite Power/Loss of Forced Circulation

ATTACHMENT 3
Sequence of Events

Unit 2 Sequence of Events

0740	4.16KV Switchgear 3 Bus Trouble Alarm Generator Negative Sequence Alarm 4.16KV Switchgear 4 Bus Trouble Alarm
0741	Main Transformer B Status Trouble Alarm Main Transformer A Status Trouble Alarm ESF Bus Undervoltage Channel A-2 ESF Bus Undervoltage Channel B-2 LOP/Load Shed B ESF Bus Undervoltage Channel B-3 DG Start Signal B LOP/Load Shed A ESF Bus Undervoltage Channel A-4 DG Start Signal A LO DNBR Channels A, B, C, & D Trip RPS Channels A, B, C, & D Trip Main Generator 525KV Breaker 935 Open Mechanical Overspeed Trip of Main Turbine
0751	Manually initiated Main Steam Isolation Signal
0755	Declared an Alert for Loss of All Offsite Power to Essential Busses for Greater than 15 minutes
0901	Energized 13.8KV Busses 2E-NAN-S03 and 2E-NAN-S05
0927	Energized 4.16KV Bus 2E-PBA-S03
0951	Exited Alert
1001	Energized 13.8KV Bus 2E-NAN-S01
1024	Energized 13.8KV Bus 2E-NAN-S02
1132	Started Charging Pump A
1618	Engineering and Maintenance review concluded that Charging Pump E was available for service after fill and vent
1714	Started Charging Pump E
1716	Started RCP 1A
1722	Started RCP 2A
1806	Stopped RCPs 1A and 2A on low motor amperage. ECC contacted to adjust grid voltage as-low-as-possible

ATTACHMENT 3
Sequence of Events

Unit 2 Sequence of Events

2040	Started RCPs 1A and 2A
2051	Stopped RCPs 1A and 2A on low running amperage
6/15	
0400	Started RCPs 1A and 2A
0610	Exited Emergency Operating Procedures

ATTACHMENT 3

Sequence of Events

Unit 3 Sequence of Events

07:40	Gen undervoltage neg sequence master turbine trip 3ENANS01 bus undervoltage Reactor trip circuit breakers open
07:41	exc volt regulator mode change Unit 3 Gen 525 KV bkr 985 opens phase Gen B &C current alarm generator field current ESF bus undervoltage ch A-2 LOP load shed B EDG B start signal CEDM MG set A & B input Bkr open LOP load shed A EDG A start signal Turbine overspeed mechanical trip ESF Bus UV A-1;A-4 alarm 13.8 Kv swgr 1 & 2 load shed Main Generator Gross MW low (402 MW) Power load Unbalance alarm VOPT Ch A, B, C & D Turbine Bypass Gp X quick open
07:42	lo SG press Unit 3 Gen 525 Kv Bkr 988 open
07:43	MSIS actuates automatically on Lo SG press
23:41	started RCP 1A
23:45	started RCP 2A
6/15	
00:40	exited EOP
16:37	Started RCP 1B
6/16	
02:07	started RCP 2B

ATTACHMENT 3

Sequence of Events

Miscellaneous

Ex2

0741 Loss of Off-Site Power

0750

0754 Unit 2 Alert

0758 Unit 1, 3 NOUE

Ex2

0759 Unit 2 NAN sent by radio

0800

Ex2

0807 Unit 1 NAN signed (not sent)*

0815

Ex2

0817 TSC D/G Tripped*
OSC Staffed

0818 Unit 2 NAN initiated*

0819 ERDS activated

0840 NRC ENS notification

0854

Ex2

0900 Unit 1 Intermediate Bus (S06) re-energized from S/U Transformer

0900

0909

0911
0927

Ex2

ATTACHMENT 3

Sequence of Events

Miscellaneous

0930	TSC Staff relocated to STSC
	Ex 2
0936	
0951	Unit 2 downgraded to NOUE
0952	EOF staffed TSC staff moved from STSC to TSC
	Ex 2
1001	Last TSC Key person on-site
1005	Unit 2 NOUE transmitted from EOF
1027	TSC staffed* EC turnover complete
1030	
1038	
1040	Ex 2
1042	
1045	
1207	Event Terminated
1215	NAN for event termination transmitted by EOF
1216	TSC secured

<u>ATTACHMENT 4</u>

FIGURES

FIGURE 1 -

ATTACHMENT 5

PROPRIETARY INFORMATION

ATTACHMENT 5

8.0 Proprietary Information

8.1 Electrical Grid Stability

a. Inspection Scope

The team reviewed the local electric grid stability following the June 14, 2004, loss-of-offsite power event to enure the adequacy of the grid protection to prevent cascading of 500kV and 230kV switchgear. In addition, the team reviewed local switchyard, substation, generator, and transmission line protective relay schemes to ascertain if any generic grid reliability or independence weakness could be identified.

b. Observations and Findings

Ex

ATTACHMENT 5

Ex 2

a. Inspection Scope

The team interviewed members of the licensee's emergency planning organization and security department and reviewed security department logs to determine the cause of encountered during the loss of off-site power. The team reviewed security procedures, the licensee's initial findings and immediate corrective actions taken on June 17, 2004. The team also reviewed the licensee's preliminary findings attached to significant CRDR 2715749 initiated to investigate and determine the root causes for the arising from the loss of off-site power and plant trip on June 14, 2004.

Ex

b.

<u>ATTACHMENT 6</u>

UNRESOLVED ITEMS

URI 05000528/2004012; 05000529/2004012; 050005308/2004012-001	Review licensee's root and/or apparent cause determination, corrective actions, and compliance associated with a number of loss-of-offsite power event related issues. (See Table 1)
URI 05000528/2004012; 05000529/2004012; 050005308/2004012-002	Review design control and compliance aspects of a number of loss-of-offsite power event related issues. (See Table 1)
URI 05000528/2004012; 05000529/2004012; 050005308/2004012-003	Review use of Plant Technical Specifications during emergencies. (See Table 1)

ATTACHMENT 6

Table 1

Focus Area	Potential Issues/Apparent Cause	Tracking	Recommendations
Off-site Power Systems	Reliability of 230kV protective relays *1. The redundency of the protective relay scheme has been improved by APS.* *2. APS has indicated that OC protection would be installed on their 230kV transformers.* *3. Modifications to included double trip coils on the WW and Devers breakers is being considered.*	URI 2004012-01	1. Verify that over current protection installed on Arizona Power System transformers connected to Palo Verde 500kV systems. 2. Verify that breakers in West Wing and Devers have been modified to include dual trip coils.
	Independence of 500kV transmission *1. Hassayampa negative sequence protective relaying was removed by APS*	N/A	No action needed
U2, Train "A" Emergency Diesel Generator Failure	Apparent cause of EDG failure was failure of diode in exciter rectifier circuit. [OK] Resulted in loss of power to Train "A" ESF busses. Note: Diode failed after 75 hours of service.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Verify that licensee's corrective actions are consistent with industry operating experience for these types of diodes.
Emergency Response Organization Challenges	Problems were identified with the emergency notification of state and local officials.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.

ATTACHMENT 6

Focus Area	Potential Issues/Apparent Cause	Tracking	Recommendations
	Problems were identified with the ability to develop protective action recommendations following a LOOP.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.
	Problems were identified with the implementation of emergency response organization notification of an event.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.
U1, Atmospheric Dump Valve 185 Failure	Apparent cause was internal control air leakage allowing valve to drift close on low demand signals. [OK] Minor operator distraction during event. Note: Licensee still troubleshooting	URI 2004012-01	1. Review licensee determination of root and contributing cause(s) 2. Review licensee's extent of condition analysis 3. Verify licensee's corrective actions consistent with industry operating experience for AOVs
U1, Letdown Heat Exchanger Isolation Failure	Apparent cause was poor design control, inadequate training on design modification, and inadequate procedures. [OK] Moderate operator distraction during event.	URI 2004012-02	1. Review adequacy of temporary modification. 2. Review adequacy of training. 3. Review adequacy of procedures.

ATTACHMENT 6

Focus Area	Potential Issues/Apparent Cause	Tracking	Recommendations
U3, Response to Loss-of-Offsite Power	Bypass valve control system caused a Unit 3 main steam isolation. The licensee declared apparent cause as control system "anomaly." The teams review found potential design issues.	URI 2004012-01	1. Review the electrical characteristics of the U3 event. Focus particularly on how the control cabinets are powered and what role the D-11 static switch had on the controls. 2. Review licensee determination of cause and corrective actions 3. Determine if a design control violation occurred 4. Compare control system design to analyses assumptions. 5. Review extent of condition. 6. Assess significance
	Given the actual plant conditions, the team could not explain why U3 responded differently than U1 and U2. The licensee noted that the generator excitation current on the U3 generator responded differently than expected and plans on conducting an evaluation of the exciter control system. This may explain both the VOPT and the bypass valve control cabinet anomaly.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Determine if a finding or violation occurred and assess significance.
U3, Reactor Coolant Pump Lift Oil Pump Breaker Thermal Overloads	Reactor coolant pump lube oil lift pump circuit breaker thermal overloads are only set 0.1 amp above normal running current. This results in increased probability of breaker tripping and operator distraction during plant recovery.	URI 2004012-02	1. Review design of thermal overload protection of RCP lube oil pump breakers. 2. Assess significance of delay on plant recovery.
	Reactor coolant pump starting procedures do not caution operators on potential thermal overload trip if pumps are operated for an extended duration.	URI 2004012-02	1. Review design control aspects of modifications to the thermal overload protection of RCP lube oil pump breakers. 2. Determine if design control or procedure violation occurred.

ATTACHMENT 6

Focus Area	Potential Issues/Apparent Cause	Tracking	Recommendations
U3, Low Pressure Safety Injection System In-leakage	Operators were required to manually implement low pressure safety injection system depressurization procedures to prevent over-pressurization. Operator distraction. Licensee apparent cause involved a thermal and hydraulic phenomena that caused the leakage. [Not OK] Most likely apparent cause was mechanical misalignment of Borg-Warner check valves.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Determine if a finding or violation occurred focusing particularly on the effectiveness of Borg-Warner corrective actions from past issues. 4. Focus on whether the licensee is adequately assuring check-valve operability. 5. Focus on adequacy of check-valve as-found testing and what the results of as-found testing imply about operability. 6. Assess significance.
General Electric Magna Blast Breakers	Two GE Magna Blast breakers failed to operate upon demand during plant recovery. The licensee's apparent cause was that the breakers "were not cycled often enough." [Not OK] NRC raised issues associated with licensee's apparent cause and planned review.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Review licensee's use of industry operating experience for GE Magna Blast breakers. 5. Assess whether the issues identified involved any human performance or PI&R aspects. 6. Determine if a finding or violation occurred and assess significance.
Auxiliary Feedwater System	During plant recovery, U1 experienced thermally induced vibration of the feedwater piping.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.

ATTACHMENT 6

Focus Area	Potential Issues/Apparent Cause	Tracking	Recommendations
	Emergency procedures which direct a main steam isolation do not caution operators on the fact that the MSIS isolated TDAFW steam drains. The emergency procedures do not result in the implementation of manual drain processes to ensure TDAFW operability.	URI 2004012-02	1. Review design control aspects of the TDAFW manual drains. 2. Determine if a design control or inadequate procedure violation exists. 3. Assess whether the issues identified involved any human performance or PI&R aspects.
	Following the 1990 TDAFW overspeed trip, the licensee directed corrective actions that included procedure revisions and the use of manual drains to ensure operability.	URI 2004012-02	1. Review design control aspects of the TDAFW manual drains. 2. Determine if a design control or inadequate procedure violation exists. 3. Assess whether the issues identified involved any human performance or PI&R aspects. 4. Assess the adequacy of previous corrective actions.
	Assess licensee management emergency response effectiveness in directing the equipment needed to manually drain the TDAFW steam traps away from U2 (the unit with one ESF bus denergized).	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess significance.
Use of Plant Technical Specifications	Inspectors noted that the licensee did not enter TS LCO's until EOP's directed a review of LCO status. This occurred very late into EOP implementation. In addition, when the LCO was entered, the time clock started when directed in the EOPs. This resulted in LCO entry hours after the condition occurred. If the practice continued, the inspectors were concerned that some TS LCO Action Statements could not be implemented when necessary.	URI 2004012-03	1. Evaluate potential Conduct of Operations and TS violations for the event: a. TDAFW operability b. U2 EDG operability c. U2 Train "A" Battery Charger d. U3 Low Pressure Safety Injection 2. Assess significance.

ATTACHMENT 6

Focus Area	Potential Issues/Apparent Cause	Tracking	Recommendations
Technical Support Center Emergency Diesel Generator Trip	Licensee electrician failed to return test switch to the normal position following a test run six-days prior to the event.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.
U2 Station Battery	Considering the discharge of the U2 station battery, need to evaluate whether battery discharge characteristics are as expected.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.
U2 Train "E" Positive Displacement Charging Pump Trip	The team found that the actions of the Control Room Supervisor not to be in accordance with the requirements of the emergency operating procedure for the plant conditions at the time... did not follow EOP...	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.
	The team found that the auxiliary operator did not implement Appendix 10, Step 1 of emergency operating Procedure 40EP-9EO10. Instead of requesting a radiation protection person to accompany him, the operator went to the radiologically controlled area access to perform a routine entry.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.
	The team found that the auxiliary operator did not properly implement emergency operating Procedure 40EP-9EO10 as required.	URI 2004012-01	1. Review licensee determination of root and contributing cause(s). 2. Review licensee's extent of condition analysis. 3. Assess licensee corrective actions. 4. Determine if a finding or violation occurred and assess significance.

ATTACHMENT 6