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RECIP.NAME RECIPIENT AFFILIATION

SUBJECT: LER 88-016-03:on 880514,reactor trip following earlier than anticipated criticality.

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JAMES M. LEVINE
VICE PRESIDENT
NUCLEAR PRODUCTION

192-00666-JML/TRB/DAJ
May 25, 1990

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Unit 1
Docket No. STN 50-528 (License No. NPF-41)
Licensee Event Report 1-88-016-03
File: 90-020-404

Attached please find Supplement No. 3 to Licensee Event Report (LER) No. 1-88-016-00 prepared and submitted pursuant to 10CFR50.73. As discussed with Mr. J. B. Martin, this supplement is being provided to update the results of APS' investigations and to provide a current status of the corrective actions. In accordance with 10CFR50.73(d), we are forwarding a copy of the LER to the Regional Administrator of the Region V office.

If you have any questions, please contact Mr. Thomas R. Bradish, Compliance Manager at (602) 393-2521.

Very truly yours,

James M Levine

JML/TRB/DAJ/tlg

Attachment

cc: W. F. Conway (all w/attachment)
J. B. Martin
A. C. Gehr
D. H. Coe
T. L. Chan
J. R. Newman
INPO Records Center

IE22
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NRC FORM 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WTH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

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Palo Verde Unit 1	0 5 0 0 0 5 2 8	1 OF 2 1

TITLE (4): Reactor Trip Following Earlier Than Anticipated Criticality

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 5	1 4	8 8	8 8	0 1 6	0 3	0 5	2 5	9 0	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): 2

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check one or more of the following)* (11)

[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER *(Specify in Abstract below and in Text, NRC Form 366A)*
[ ] 20.405(a)(1)(iii)	[X] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
Thomas R. Bradish, Compliance Manager	6 0 2	3 9 3 - 2 5 2 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES *(If yes, complete EXPECTED SUBMISSION DATE)* [X] NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT *(Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines)* (16)

At approximately 0335 MST on May 14, 1988, Palo Verde Unit 1 was in Mode 2 (STARTUP) when a reactor trip occurred as the Control Element Assemblies (CEA's)(AA) were being inserted following an attempt to startup the reactor. The trip occurred when conservative Radial Peaking Factors (RPF) were utilized by the Core Protection Calculator (CPC)(CPU)(JC) as the CEA's were being inserted. There were no other safety system responses (including ESF actuations) and none were necessary. The plant was immediately stabilized in Mode 3.

The CEA's were being inserted after criticality had been achieved earlier than calculated. The criticality resulted in the CEA's being below the Power Dependent Insertion Limits of LCO 3.1.3.6. The root cause of criticality outside established guidelines has been determined to be non-conservative operator performance during the reactor startup. Errors in the information utilized for calculating the Estimated Critical Condition (ECC) contributed to this event.

The corrective action to prevent recurrence was to correct the errors in the information utilized for the ECC and improve the administrative controls for utilizing the ECC. Appropriate disciplinary action was taken.

There have been no previous similar events reported pursuant to 10CFR50.73.

This is a supplement to LER 1-88-016-02.

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

On May 14, 1988, Palo Verde Unit 1 was in Mode 3 (HOT STANDBY) at normal operating temperature and pressure. A reactor startup was in progress following a trip from 91 percent power which had occurred approximately 38.5 hours earlier.

B. Reportable Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification:

Automatic actuation of the Reactor Protection System. Condition prohibited by the plant's Technical Specifications.

On May 14, 1988, Palo Verde Unit 1 was in Mode 3 (HOT STANDBY) conducting a reactor (AC)(RC) startup. During the reactor startup, the reactor achieved criticality prior to that calculated by the Estimated Critical Condition (ECC). Since there was a significant discrepancy between the plant response and the ECC, control room supervision (utility, licensed) decided to insert Control Element Assemblies (CEA)(AA) to calculate a new ECC. As the CEA's were being inserted, a reactor trip occurred at approximately 0335 MST on May 14, 1988. The trip was uncomplicated and the plant was immediately stabilized in Mode 3.

The startup began at approximately 0100 MST by withdrawing the Shutdown (SD) CEA's banks and the Part Length CEA's (PLCEAs). The reactor had been shutdown for approximately 38.5 hours prior to the trip. The Estimated Critical Rod Position per the ECC was 90 inches withdrawn on Regulating (Reg) Group 4 with a boron concentration of 1033 ppm presuming a startup time of 0000 MST. The Primary Operator (utility, licensed) completed withdrawal of the SD banks and the PLCEA's at approximately 0159 MST. Withdrawal of the Regulating Groups began at approximately 0304 MST.

The count rate, obtained from the Startup Channels (IG)(XI), was approximately 300 counts per second (cps) when Reg Group 1 was 0 inches withdrawn. The startup was conducted in accordance with 41OP-1ZZ03, "Reactor Startup", with the regulating CEA's being withdrawn in 30 inch increments per step 4.3.12. After each

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withdrawal increment, a pause was established to allow count rate/power level to stabilize. Additionally, the Shift Technical Advisor (STA) (utility, licensed) was recording count rate after each 30 inch withdrawal. This was started when Reg Group 1 was being withdrawn even though the procedure only requires that power level be recorded and plotted with each 30 inch withdrawal after reaching 60 inches withdrawn on Reg Group 3 and thereafter.

The Primary Operator (utility, licensed) complied with section 4.3.12 of the procedure and withdrew Reg Groups 1 and 2 in 30 inch increments. When Reg Group 3 was withdrawn to 30 inches, the Primary Operator (utility, licensed) questioned the STA concerning count rate and was told that it had stabilized (the STA noted that the count rate was approximately 1277 cps). Count rate was noted to have doubled twice since beginning the withdrawal of Reg Group CEA's. Since criticality was imminent, the Control Room Supervisor (CRS) (utility, licensed) checked the Power Dependent Insertion Limits (PDILs) of Specification 3.1.3.6. Technical Specification LCO's 3.0.4 and 3.1.3.6 specify that in order to enter Mode 2 (STARTUP) with Keff greater than or equal to 1.0, the CEAs in Reg Group 3 must be at least 60 inches withdrawn. With the count rate stable at approximately 1277 cps, the Primary Operator pulled Reg Group 3 to 45 inches withdrawn. While the CEA's were being withdrawn to 45 inches, the startup channels (IG) were deenergized in accordance with the procedure at approximately 2000cps. Power level was then monitored on the log power channels (IG) after observing proper overlap on the startup channel and log power channel.

Upon reaching 45 inches withdrawn on Reg Group 3, the startup rate was still not definitely positive and power level had stabilized. Since the reactor was not yet critical, the Primary Operator commenced pulling Reg Group 3 to 60 inches withdrawn. The CEA withdrawal from 45 inches to 60 inches was made in three steps taking approximately one (1) minute to complete. After the 15 inch withdrawal, the CRS concluded that the reactor was slightly supercritical and, hence, the critical CEA position was between 45 inches and 60 inches. (Note: The measure of criticality is actually based on the indication of a positive startup rate and an increasing power level without CEA motion. Thus, the reactor is actually brought to a supercritical condition.)

The CRS directed the Primary Operator not allow power to exceed 1E-03 percent. The Primary Operator initiated CEA insertions to stabilize power at less than 1E-03 percent power. The CRS then

conferred with the Shift Supervisor on what action to take. Since their was a significant discrepancy between the plant response and the ECC, they decided to insert Reg Group 3 to 0 inches withdrawn and investigate the deviations from the ECC. The direction to insert Reg Group 3 to 0 inches was given to the Primary Operator who then complied. It should be noted that Reg Group 3 was 60 inches withdrawn for approximately 2 minutes, 39 seconds.

When the CEA's reached approximately 25 inches withdrawn, an auxiliary trip was generated by Core Protection Calculators (CPC) (CPU)(JC) Channels B and C on high Radial Peaking Factors. The Reactor Trip Switchgear (SWGR) operated as designed, and CPC channels "A" and "D" tripped as expected. The plant was immediately stabilized in Mode 3. The event was diagnosed by the Assistant Shift Supervisor (utility, licensed) as an uncomplicated Reactor trip and performance of the appropriate procedure was initiated.

The reactor was subcritical at the time of the trip. No Engineered Safety Features (ESF) actuations were received or required. The Emergency Plan was not initiated and no emergency classification was made.

During APS's Post Trip Review evaluation, it was determined that the reactor had gone critical between 50 and 55 inches withdrawn on Group 3. Based upon criticality being achieved below 60 inches withdrawn, Unit 1 operated in a condition prohibited by Technical Specification 3.0.4 in that criticality was achieved without meeting the conditions of LCO 3.1.3.6.

C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

Not applicable - no structures, systems, or components were inoperable at the start of the event which contributed to the event.

D. Cause of each component or system failure, if known:

Not applicable - no component or system failures occurred.

E. Failure mode, mechanism, and effect of each failed component, if known:

Not applicable - no component failures occurred.

F. For failures of components with multiple functions, list of systems or secondary functions that were also affected:

Not applicable - no component failures occurred.

G. For failures that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the trains were returned to service:

Not applicable - no failures occurred which rendered a train of a safety system inoperable.

H. Method of discovery of each component or system failure or procedural error:

There were no component or system failures involved. The errors discussed in Section I below were identified during the post trip review process conducted by APS.

I. Cause of Event:

The cause of the reactor trip was an Auxiliary Trip generated by the CPC's. The Auxiliary Trip resulted from conservatively high Radial Peaking Factors being generated as Regulating Group 3 CEA's were being inserted below 30 inches. In general, the conservatively high Radial Peaking Factors may result in a reactor trip when Group 3 is less than 95 inches withdrawn and the CPC's are not bypassed.

APS procedures delineate that the CPC trip buffers are not to be reset until Reg. Group 3 is withdrawn to greater than or equal to 95 inches. The CPC's cannot be reset unless Reg Group 3 is withdrawn sufficiently to reduce the integrated one-pin peak value below the auxiliary trip setpoint (at the time of this event, that position was approximately 27 inches withdrawn). Since the reactor went critical with Group 3 below 95 inches and the CPC trip buffers had not been reset, this resulted in the inability of the CPC's to record actual trip data. If the data was available, APS could have verified the presence of the auxiliary trip. Using the CPC simulator, it was later verified that at less than 30 inches withdrawn on Reg Group 3, an auxiliary trip was correctly generated by the CPC's due to high Radial Peaking factors. Even though the actual trip buffers for the event were unavailable, the re-creation of the event using the CPC Simulator verified that this was the cause of the reactor trip.

The cause of the condition prohibited by the plant's Technical Specifications wherein the reactor achieved criticality below the limits of LCO 3.1.3.6 has been determined to be control room personnel (utility, licensed) performance which was considered to be less conservative than appropriate for the situation during the reactor startup. It was determined that the control room personnel did not act with the desired conservatism in performing the approach to criticality based upon the information available at the time. During the approach to criticality, the control room personnel correctly performed and followed procedures and responded to alarms and permissives to bypass High Log Power trips. However, APS Management considers that the degree of conservatism utilized based upon indications of early criticality was not in accordance with management expectations and is considered to be cognitive personnel error on the part of control room supervision (utility, licensed). As a result of this concern, APS performed a Control Room Staff Evaluation. The results of this evaluation are provided in Section V. There were no unusual characteristics of the work location which contributed to this event.

Some of the information being utilized by the Control Room personnel was later determined to be incorrect and/or inadequate. The Control room personnel's use of this information contributed to the nonconservative actions. The ECC being utilized by control room personnel contained inaccuracies which resulted from: (1) an inaccuracy in the computer program which calculates transient xenon level and (2) a startup procedure which allowed a 4 hour deviation from the projected startup time (At the time of the approach to criticality, approximately 3.5 hours had elapsed from the projected startup time. During this time period, Xenon decay caused a positive reactivity change). The information and controls available for use by control room personnel in evaluating the conditions present during the approach to criticality were determined to be inadequate. That is based upon the fact that the Core Data book did not contain integrated CEA worth curves for Group 3 below 60 inches, and an inverse count ratio plot (1/M plot) was not required by procedure to be started until Group 3 reached 60 inches withdrawn.

During the Post-Trip Review investigation, a concern arose that the boronometer (XI) being utilized for determining boron levels in the Reactor Coolant System (RCS) (AB) may not have provided accurate indication of boron concentration. Engineering subsequently evaluated the operation of the boronometer and determined that the difference between the indicated boron

concentration and the value obtained by chemical analysis was the result of normal system inaccuracies at different boron concentrations. No system malfunctions occurred.

J. Safety System Response:

Reactor Protection System Actuation occurred at approximately 0335 MST on May 14, 1988.

K. Failed Component Information:

Not applicable - There were no component failures.

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:

There were no safety consequences or implications resulting from this event. As described above, the reactor tripped as designed and all safety responses necessary to place the plant in a stable condition functioned properly.

The criticality earlier than calculated in the ECC had no adverse safety consequences or implications. As described above, Unit 1 was critical with the CEA's below the transient PDIL limit of Specification 3.1.3.6. Operation in this condition is permitted for up to two (2) hours pursuant to ACTION "a" of LCO 3.1.3.6. The CEA's were below the PDIL limit for less than 10 minutes. It should be noted that the PDIL limits of Specification 3.1.3.6 are established to ensure that an adequate shutdown margin is maintained and at the same time ensure that the potential effects of a CEA ejection accident are limited to acceptable levels. The function of the shutdown margin requirement is to ensure that the reactor remains subcritical following a design basis accident or anticipated operational occurrence. Shutdown margin requirements vary throughout the core life as a function of fuel depletion and reactor coolant system (RCS) cold leg temperature. The most restrictive condition occurs at the end of core life, with cold leg temperature at no-load operating temperature, and is associated with a postulated steam line break accident and the resulting uncontrolled RCS cooldown. In the analysis of this accident, the specified shutdown margin is required to control the reactivity transient and ensure that the fuel performance and offsite dose criteria are satisfied. An analysis of the conditions present during the event has determined that the boron concentration was approximately 120 parts per million greater than necessary to meet shutdown margin requirements.

III. CORRECTIVE ACTIONS:

A. Immediate

When control room personnel (utility, licensed) noted that criticality had been achieved earlier than calculated in the ECC, appropriate actions were taken to shutdown the reactor and place it in a safe condition by inserting Group 3 to zero inches until the problems with the ECC could be investigated.

As described above, the reactor trip occurred as the CEA's were being inserted below approximately 25 inches withdrawn. Following the trip, control room personnel (utility, licensed) took the appropriate action to ensure that the plant was in a safe condition.

B. Action to Prevent Recurrence:

Appropriate procedure precautions were implemented to ensure that control room personnel were aware of the possibility of reactor trips when Regulating Group 3 CEA's were less than 95 inches withdrawn and the CPC's were not bypassed.

Note: This conservatism with the CPC's has been determined not to be required. The CPC software has been revised and the procedural precautions are no longer necessary.

Concerning the cognitive personnel errors described in Section I.I wherein non-conservative operator performance was involved, appropriate disciplinary action and counseling was taken.

Concerning the error in the ECC, the following actions were taken:

* The ECC and Reactor Startup procedures were modified to require that the projected time of criticality used for the ECC must be within one hour of the actual time of criticality.

* The computer program which calculates transient xenon levels was modified.

* RCS boron samples were utilized for plant startup in lieu of boronometer readings until the instrumentation was verified to be operating properly.

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* Information and direction for starting inverse count ratio plots earlier in the startup process were implemented.

* An engineering analysis on the existing ECC calculation methodology was performed. Based upon this analysis, appropriate controls were implemented.

Concerning the information and methodology for starting up the reactor, the following corrective actions were taken:

* The integrated CEA worth curves below 60 inches have been included in the Core Data Book.

* The reactor startup procedure was revised to include the information contained in the Core Data Book.

* A reactor engineer (utility, non-licensed) was required to be in the Control Room (NA) during reactor startups until the appropriate administrative changes were completed.

As a result of the Control Room Staff Evaluation, the following corrective actions were taken:

* A review of the Control Room communications during this event was conducted and guidance on declaring criticality was promulgated. (The results of the review of Control Room communications are discussed in Section VI.A.)

* Management issued a letter reminding all plant personnel to adopt a conservative approach when conditions or indications are other than expected.

* A Human Performance Evaluation System evaluation was performed by the STA Group. (The results of the HPES are described in Section VI.A.)

IV. Previous Similar Events:

There have been no previous similar events reported pursuant to 10CFR50.73 involving a reactor trip following a criticality earlier than anticipated by the ECC. However, a similar trip occurred as reported in Unit 1 LER 88-011-00 when overly conservative Radial Peaking factors (RPF) utilized by the CPC resulted in a reactor trip. As discussed in LER 88-011-00, the conservative RPF values were part of the original design of the CPC software. APS has modified the software.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

V. ADDITIONAL INFORMATION

A. The following information was developed as a result of a Control Room Staff Evaluation conducted by APS:

SHIFT SUPERVISOR (Utility, Licensed)

The Shift Supervisor (SS) was in the "horseshoe" area. It was his intention to maintain a broad perspective on overall plant response and therefore was not directly involved with the specifics of the criticality. When he was consulted by the CRS, the SS concurred with the CRS's recommendation that the Group 3 CEA's be reinserted to 0 inches. APS believes the Shift Supervisor should have been more involved in this evolution.

CONTROL ROOM SUPERVISION/ASSISTANT SHIFT SUPERVISOR (Utility, Licensed)

The CRS was directing the reactor startup activities. The CRS was using the correct procedure for the evolution. The startup was proceeding in a controlled and "unhurried" manner. The CRS had discussed the potential for criticality earlier than anticipated due to Xenon decay with his Primary Operator. The Primary Operator indicated he understood the discussion.

When Group 3 was at 30 inches, it was apparent to the CRS that, based on the count rate information, the reactor would go critical very close to 60 inches. Due to the apparent large difference between the suspected early criticality of approximately 60 inches on Group 3 and the ECC of 90 inches on Group 4, the CRS should have taken a more conservative approach and reevaluated the ECC prior to continuing the startup. When Reg Group 3 was at 60 inches, the CRS recognized that the reactor had gone critical during the last rod withdrawal. He then directed the Primary Operator to maintain reactor power less than 1E-03 percent of rated thermal power while he consulted with the SS.

It was the understanding of the CRS that the Reactor Operator actually pulling CEAs is the one who actually "calls" criticality. The CRS, upon recognizing that the reactor was critical, asked the Primary Operator, "What are the indications of criticality?". This was done in order to prompt the operator to "call" criticality. In this case the CRS should have been more direct with his communications to the Primary Operator with regard to what information he wanted with respect to the condition of the reactor, i.e. ,by asking "Is the reactor critical?" It should also be recognized that there were no formal guidelines regarding

who on the Control Room staff should or must "declare criticality." APS Management believes that the CRS should have directed that the evolution be stopped when it became apparent that criticality could be achieved earlier than anticipated.

Following the Reactor Trip, the CRS directed the Operators to maintain their safety functions and the plant was stabilized in Mode 3.

Nuclear Operator (NO) III - PRIMARY OPERATOR (Utility, Licensed)

The Primary Operator was pulling the CEA's under the direction of the CRS. He observed the power level increase above the point where the Log Power Channel could be bypassed and the CPC channels become "active." Based on the interview with the Primary Operator, he believed the reactor to be critical at approximately 60 inches withdrawn on Reg Group 3. Actions were taken by the Primary Operator to insert the CEA's in order to maintain the reactor at less than 1E-03 percent power at the direction of the CRS. Before the reactor was stabilized and the critical point data could be taken, it was decided to reinsert Group 3. Therefore, criticality was not formally stated nor entered in the Control Room logs. Criticality should have been entered in the Control Room logs as a late entry.

The indications present with Group 3 at 30 inches indicated that subsequent withdrawals would be very near, if not at, criticality. The Primary Operator should have shown more concern with these indications, and at least questioned, the CRS. A more conservative action would have been to recalculate the ECC prior to continuing the Startup. The Primary Operator should have recognized indications of criticality prior to being "prompted" by the CRS.

APS believes the Primary Operator should have stopped the evolution when it became apparent that criticality would be achieved earlier than anticipated.
NO III - SECONDARY OPERATOR (Utility, Licensed)

The Secondary Operator was performing the Main Turbine Warmup in preparation for secondary plant startup.

NO III - CONTROL ROOM (Utility, Licensed)

Was not directly involved in startup.

SHIFT TECHNICAL ADVISOR (Utility, Licensed)

The Shift Technical Advisor (STA) was observing the progress of the startup and recorded count-rates periodically during withdrawal of the Shutdown groups and Regulating groups. He indicated that the count rates had doubled twice during the course of the rod withdrawal. The STA should have been more aggressive in providing this information to the Control Room staff. This would have provided additional indication to the Control Room on their nearness to criticality.

APS Management believes that the STA should have been more involved in monitoring the startup activities and providing direct communication that the reactor was nearing criticality. He should have recommended to the SS that the evolution be stopped when it became apparent that criticality could be achieved earlier than anticipated.

B. During the ENS notification, it was discussed that the reactor trip occurred as the CEA's were being inserted in order to calculate a new ECC, and the CEA's were being inserted since the reactor was approaching criticality prior to the ECC. However, it was not discussed that the reactor had achieved earlier criticality or that the PDIL's had been exceeded.

APS believes that the criticality and PDIL information should have been discussed in a subsequent ENS report.

Investigation into this aspect of the event was performed addressing whether additional reporting requirements were applicable. Based upon the results of the investigation, a Department Instruction prescribing the requirements for NRC notifications was developed. As an immediate corrective action, additional administrative controls were promulgated to provide more explicit directions for NRC notifications.

The results of this investigation are provided in Section VI.D.

C. Exact discussions of the event were impacted by information available in the various logs. APS evaluated this aspect and determined that changes were required to enhance the log keeping techniques.

The results of this evaluation are discussed in Section VI.A and VI.C.

D. As previously discussed, additional evaluations/investigations were conducted as a result of this event in both the reporting/notification aspects and in the area of Human Performance Evaluation System. Based upon the results of these evaluations Supplement No. 2 to this report was issued.

The results of the Human Performance Evaluation System review are contained in Section VI.A.

VI. SUPPLEMENTAL INFORMATION

The information in this section is provided as a result of APS's investigation into the circumstances surrounding the event described in this LER.

A. An evaluation was conducted to address those errors identified during the approach to criticality on May 14, 1988. The evaluation was performed using the INPO Human Performance Evaluation System (HPES) which was developed specifically for addressing human performance problems at nuclear power plants. During the HPES evaluation, the problems identified during the Post Trip Review (PTR) process and discussed in Section I.I. were analyzed. The HPES is intended to identify the "causal factors" affecting the root causes discussed in Section I.I. Also during the HPES evaluation, additional problems were identified and analyzed.

The following provides a summary of the HPES concerns evaluated and their respective corrective actions.

1. Criticality was not declared by the Control Room staff when it occurred.

Corrective Actions:

a. Job performance standards and requirements for the Control Room staff delineating responsibility for the declaration of reactor status were developed and implemented.

b. Procedures, instructions, and programs were revised to incorporate the specific requirements and responsibility for declaring criticality.

TEXT (If more space is required, use additional NRC Form 366A's) (17)

c. Simulator training (initial and requalification) and on-the-job training were revised to address whose responsibility it is for the declaration of reactor status based upon the policies and procedures developed.

2. The Control Room Supervisor (CRS) did not terminate the reactor startup even though count rate nearly doubled when Reg Group 3 CEA's were withdrawn from 0 to 30 inches and it became apparent that criticality would be achieved near the Power Dependent Insertion Limits (PDIL's).

Corrective Actions:

a. A policy which requires more formal communications between members of the Control Room staff was developed and implemented. The policy was incorporated into the Conduct of Shift Operations procedure and subsequently incorporated into simulator training.

b. The administrative procedures governing the STA role in Control Room operations were reviewed and revised as necessary to ensure that the STA is more effectively utilized on shift.

c. Simulator training involving scenarios where there is a large error between the Estimated Critical Condition (ECC) and the actual critical condition is being provided.

3. The reactor was taken critical below the PDIL's.

(Note: A contributory factor in this concern is that the SS on duty was a relief crew SS filling in for the normal SS).

Corrective Actions:

a. Guidance was established on the standardization and conduct of operations between crews to ensure consistency between the on-shift and replacement crew members.

b. Simulator training involving scenarios where there is a large error between the ECC and the actual critical condition is being provided.

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c. The operations crew supervision involved have been re-instructed regarding their responsibilities for unit operations including that they should be directly involved in critical evolutions by providing guidance and ensuring all aspects of the task are understood prior to task performance.

4. The ECC used for the startup was calculated for 0000 MST (approximately 3 hours and 25 minutes prior to the time criticality was achieved). An ECC for 0200 was calculated; however, it was not finalized nor was it utilized to establish a new boron concentration. The 0200 calculation was only used to predict the expected change due to xenon.

Corrective Action:

The ECC and Reactor Startup procedures were modified to require that the projected time of criticality used for the ECC must be with in one hour of the actual time of criticality.

5. APS's HPES investigation identified as a concern the fact that the Primary Operator did not recognize the nearness of the reactor to criticality when Reg Group 3 was withdrawn at 30 inches and 45 inches.

NOTE: Subsequently, the Primary Operator has stated that he was aware that the reactor was near criticality when Reg Group 3 was withdrawn at 30 inches and 45 inches.

Based upon the HPES concern, the following corrective actions were developed:

Corrective Actions:

a. An evaluation of the Primary Operator involved in the startup to determine if he possessed sufficient practical knowledge skills in applying reactor theory to instrument indications was performed. The results of this evaluation indicate that the RO possessed sufficient practical knowledge. The individual continues to maintain his license qualification requirements.

b. Simulator training was revised to include non-ideal or off-normal startup scenarios (e.g., shortly after a reactor trip or when errors in boron or xenon concentration are present). Simulator training is being conducted to ensure that operators can apply theory to plant operations by applying 1/M plots and other methods allowed by the procedure for determining critical CEA position or Boron concentration.

6. Rod Worth data for Reg Groups 1 and 2, and Group 3 below 60 inches were not included in the Core Data Book.

Corrective Actions:

a. The review process for changes related to core reloads has been upgraded.

b. The procedural controls for the Core Data Book were reviewed and revised to ensure that the data provided adequately meets the needs of the users.

c. The training and qualification requirements for the Engineering Evaluations Department Reactor Engineering staff has been upgraded to include an integrated knowledge of the effect of core reloads.

7. New core reload calculations included high radial peaking factors associated with Reg Group 3 CEA's. (Note: This concern is also related to the event described in LER 88-011-00 involving a reactor trip caused by conservative peaking factors.)

Corrective Actions:

a. A more effective and productive interface has been established with Combustion Engineering (CE) concerning specific operating practices at Palo Verde.

b. The review process for changes related to core reloads has been reviewed and upgraded.

c. The training and/or qualification requirements for the Fuels Management staff responsible for core reloads has been reviewed and upgraded as necessary.

d. Transient Data Acquisition System (IQ) data is being made available to the Safety Analysis group.

8. The "Xenon" computer program used to calculate the reactivity due to xenon had large uncertainties due to incorrect coefficients.

   Corrective Action:

   The administrative control requirements for the Xenon program (e.g. determining and verifying the correct xenon distribution coefficients) were evaluated and have been upgraded. The upgraded administrative controls ensure that the Xenon program is sufficiently accurate for: 1) Determining xenon worth during transients, 2) Predicting criticality with xenon present, and 3) Quantifying the effect of xenon on shutdown margin.

9. The Compliance representative (utility, non-licensed) did not notify the Compliance Manager (utility, non-licensed) prior to making the 4-hour ENS notification.

   Corrective Actions:

   A Department Instruction prescribing the requirements for ENS notifications has been implemented and provided to Unit Operations Supervision and Compliance Engineers. As an interim measure prior to development of the instructions, the contents of a 1986 letter requiring Management notification of ENS calls was updated and disseminated to the Compliance Engineers.

10. The Shift Technical Advisor (STA) (utility, licensed) did not update his log concerning the events surrounding the approach to criticality until two days after the event.

    Corrective Actions:

    a. The STA work schedule has been evaluated and it was determined that the present schedule is the most effective use of the STA resource.

    b. The need for accuracy and completeness in the areas of shift turnover and log taking has been re-emphasized during STA staff meetings.

    c. The STA involved in this event has been counseled to assure that he has a proper understanding of the requirements of completion of all on shift tasks, particularly logkeeping.

11. The Unit Log and Control Room Log did not reflect entry into operational modes or entry into Technical Specification ACTION statements. For example, criticality was not recorded in the Unit or Control Room Logs. This information should have been entered into the logs as a "late entry".

    Corrective Actions:

    a. The "Conduct of Shift Operations" procedure was revised to require the logging of significant actions occurring during an abnormal event as late entries if those actions were not logged at the time they happened.

    b. The "Conduct of Shift Operations" procedure was evaluated and revised to include instructions requiring an on-shift supervisory review of the Control Room Log prior to the shift turnover to the oncoming crew to assure completeness of the logs.

    c. The Unit Operations Management periodically reviews Control Room and Unit Logs to assure that the logs meet the standards established in the "Conduct of Shift Operations" procedure.

    d. The logkeeping instruction during Simulator requalification training was evaluated and determined to be sufficient.

12. The Event Notification Worksheet (for making ENS notifications) did not include the fact that the reactor was critical.

    Corrective Actions:

    A procedure was developed to ensure that accurate and adequate information is obtained by the Compliance representative for NRC notification.

B. Investigation was conducted to determine the length of time it took to withdraw Reg Group 3 to 60 inches withdrawn. Based upon APS's investigation, the following Reg Group 3 to 60 inches withdrawal information is provided. The information provided is APS's best approximation of the withdrawal sequence and is based upon operator's statements and times for starting/stopping CEA motion provided by the Plant Computer (ID)(CPU).

Time (hrs, min, sec.)			Reg Group 3 Activity	Reg Group 3 Position (Approx) *
03	23	37	Withdrawal Start	0
03	24	32	Withdrawal Stop	30
03	26	55	Withdrawal Start	30
03	27	21	Withdrawal Stop	45
03	30	03	Withdrawal Start	45
03	30	25	Withdrawal Stop	52
03	30	26	Withdrawal Start	52
03	30	44	Withdrawal Stop	58
03	30	48	Withdrawal Start	58
03	30	50	Withdrawal Stop	60

* CEA positions are based upon operators statements for stops at 30, 45, and 60 inches.

C. APS's investigation into this event included an evaluation of the logs that have been maintained during reactor startups. This investigation included an evaluation of the scope and adequacy of the logs that were maintained during this event, and an evaluation of the logs that were maintained during previous reactor startups. An evaluation of Control Room logs including the logs maintained during this event identified that the logkeeping practices were inconsistent, that is, the details included in the logs and the actions recorded appeared to be dependent upon the individual making the entry instead of following pre-established guidelines. A subsequent evaluation of the guidance provided in this area determined that additional controls were necessary to establish consistency in the information recorded in the logs. Therefore, 40AC-9ZZ02, "Conduct of Shift Operations" was revised to provide more prescriptive guidance for the information required to be entered into the logs.

D. APS Licensing Department conducted an independent evaluation of the reportability aspects of this event. The evaluation was specifically conducted to determine if a one-hour notification was required pursuant to 10CFR50.72. As a result of this evaluation, it was determined that the four-hour notification conducted following the event was appropriate and that no one-hour notification was required.

E. A formal "PVNGS Incident Investigation Program" (79PR-0IP01) was developed. This program includes improvements to the post trip review process.

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F. APS's investigation into this event included an evaluation to determine if additional operator actions were required as a result of being critical below PDIL specifications. A clarification of Technical Specification Surveillance Requirement 4.1.1.2.1.b was necessary since it cross references Specification 3.1.3.6 (PDIL requirements). The concern was that if the Control Element Assemblies (CEA's) are not within the Transient Insertion Limits of Technical Specification 3.1.3.6, is immediate boration required in accordance with Technical Specification 3.1.1.2 ACTION "a" or is there a two-hour period to restore CEA's in accordance with Specification 3.1.3.6 ACTION "a".

APS has determined that operators have two hours to restore the CEA's to within the PDIL limits. Immediate boration pursuant to Technical Specification 3.1.1.2 ACTION "a" is not required unless the two-hour ACTION of Specification 3.1.3.6 cannot be met.

G. APS believes that the corrective actions taken in response to this event will be effective in preventing recurrence. Increased procedural requirements and additions to training have increased the knowledge and awareness of plant personnel. The information available to operators in the Control Room has been increased by, for example, the addition of procedural warnings and rod worth curves for all regulating groups. The performance of reactor startups has been improved by having a reactor engineer in the Control Room performing 1/M plots during reactor startups, and by procedure requiring that actual criticality be achieved within one hour of the time assumed in the predicting calculation. The additional training described in Section VI.A has been provided to plant personnel and resulted in an increased awareness of the necessity to operate the plant in a conservative manner.

Record keeping in the Control Room has been improved by continuing supervisory review of logbooks. Investigations of events and the associated documentation have been improved by the implementation of the Incident Investigation Program.

Since the May 14, 1988 event, APS management has communicated to plant personnel the importance of conservatism during operations. In addition, management has re-emphasized to plant personnel that safety always takes precedence over schedule.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WTH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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APS has reviewed the post-event performance of the Control Room personnel (utility, licensed) who were involved in the May 14, 1988 event. Not all personnel have been assigned permanent Control Room responsibilities since the event. However, each has maintained his respective NRC license even though some repeat examinations were necessary for certain individuals. Their performance during this period, in the Control Room and in their other post-event assigned responsibilities, has been evaluated by plant management to be satisfactory. Based on this performance, and the many program improvements described above, APS has concluded that these individuals can be relied upon to properly perform their respective responsibilities, including Control Room assignments.