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KNIGHTON,G. Licensing Branch 3

SUBJECT: Corrected response to 841006 request for addl info re proof & review Tech Specs.Reactor protection sys rate setpoint of 11% per minute has no adverse impact on safety analysis due to rapid rate of increase of core power.

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Arizona Nuclear Power Project
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ANPP-31156-EEVB/SRF
November 16, 1984
Corrected Copy

Director of Nuclear Reactor Regulation
Attention: Mr. George Knighton, Chief
Licensing Branch No. 3
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2 and 3
Docket Nos. STN-50-528/529/530
File: 84-056-026; G.1.01.10

Reference: Letter from G. W. Knighton, NRC, dated
October 6, 1984
Subject: Request for Additional Information-
PVNGS Technical Specification

NRC letter dated October 6, 1984 requested APS to supply information to questions asked by RSB during meetings held to discuss the Palo Verde proof and review technical specifications.

Attached are responses to those questions. It should be noted that APS previously responded to Question 6 under a separate cover letter dated November 13, 1984.

If you have any questions please contact me.

Very truly yours,

E. E. Van Brunt

E. E. Van Brunt, Jr.
APS Vice President
Nuclear Production
ANPP Project Director

EEVB/SRF/jle

cc: E. A. Licitra w/attachment
A. C. Gehr w/attachment

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STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, Edwin E. Van Brunt, Jr., represent that I am Vice President, Nuclear Production of Arizona Public Service Company, that the foregoing document has been signed by me on behalf of Arizona Public Service Company with full authority to do so, that I have read such document and know its contents, and that to the best of my knowledge and belief, the statements made therein are true.

Edwin E. Van Brunt

Edwin E. Van Brunt, Jr.

Sworn to before me this 26th day of November, 1984.

Nora E. Meador

Notary Public

My Commission Expires:

My Commission Expires April 6, 1987

Question

1. Reactor Protective Instrumentation Setpoints (Table 2.2-1, Section 2.2, page 2-3 and 2-4)

   A. Provide basis for the trip setpoint of the high pressurizer pressure on the Supplementary Protection System (SPS).

   B. Table 15.0-4 of the FSAR indicates that the analysis setpoint of the high pressurizer pressure trip is 2450 psia. Explain how the SPS pressurizer pressure-high with an allowable value of $\leq$2439 psia plus instrument uncertainty could ensure the plant operation within the conditions covered by the safety analysis.

   C. Confirm that the overpower setpoint in Table 15.0-4 of the FSAR will be modified to 11%.

   D. Provide basis of the variable overpower allowable setpoint value of 11.0%/min in light of the safety analysis assumptions.

Response

A. The basis for the Supplementary Protective System (SPS) Trip is to provide an additional trip, which is diverse from the Reactor Protective System (RPS) Trip on high pressurizer pressure, for the purposes of mitigating an ATWS transient.

B. The SPS pressurizer pressure-high trip does not ensure plant operation within the conditions covered by the Safety Analysis. The RPS trip on high pressurizer pressure ensures plant operation within the conditions covered by the safety analysis. (The safety analysis does not assume that the failure of a safety grade RPS trip occurs, i.e., the consequences of ATWS transients are not included in the safety analysis).

   The SPS pressurizer pressure-high trip was referenced in the Response to NRC Question 440.5 as the second reactor trip on high pressure. Since the NRC requires that the pressurizer safety valves be sized assuming the first reactor trip during loss of load events does not function, the sizing of these valves is based on the SPS pressurizer pressure-high trip occurring at an analysis setpoint value of 2450 psia. The total instrument uncertainty for the SPS pressurizer pressure-high trip is 36 psi. Therefore, Table 2.2-1 of the Technical Specifications has been revised to indicate that the SPS pressurizer pressure-high setpoints are reduced as attached.

C. The variable overpower ceiling setpoint in Table 15.0-1 of the PVNGS FSAR will be modified to read 117% for all transients except for steam and feedwater line breaks inside containment for which it will remain at 116%.

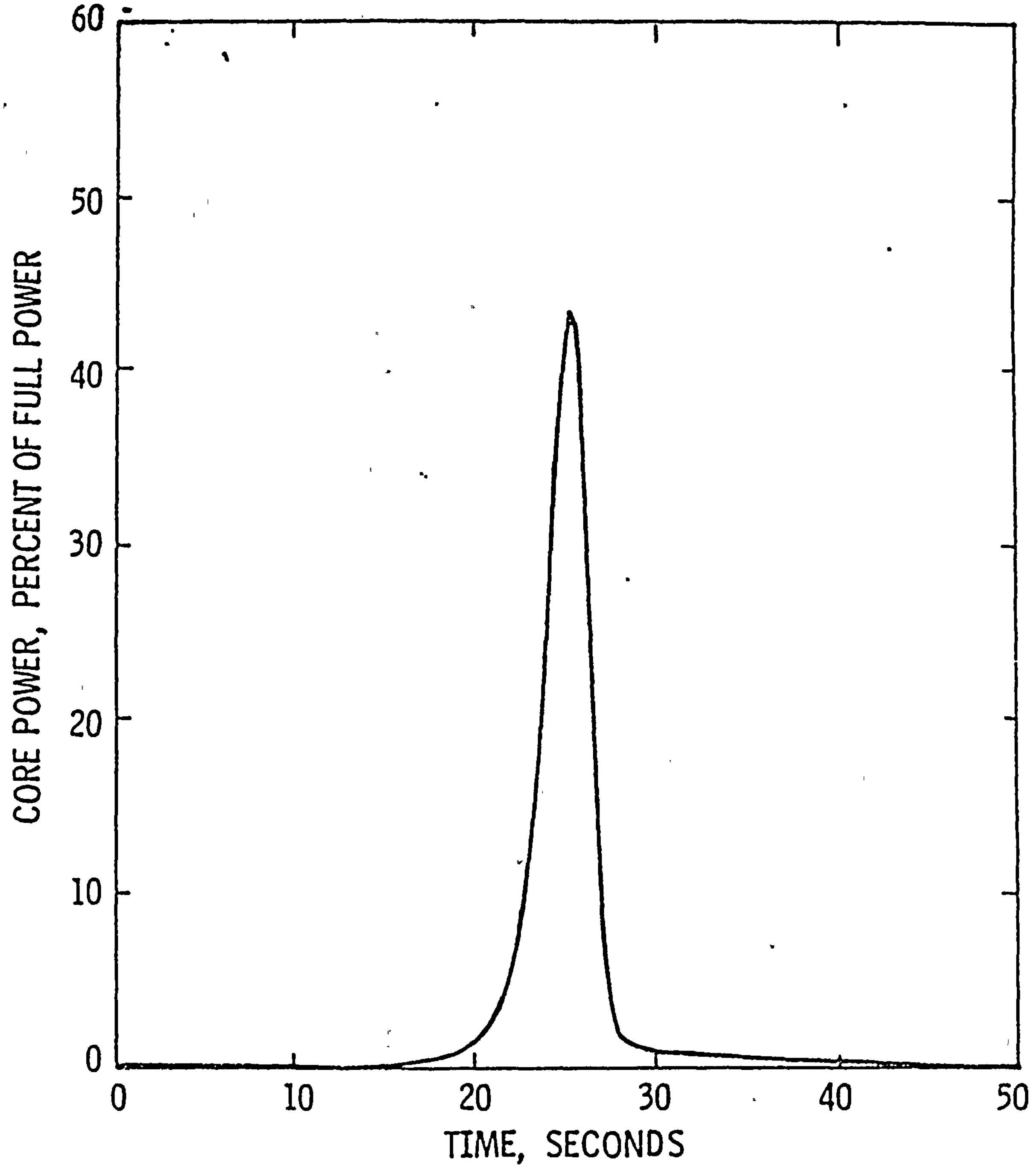
D. In the Chapter 15 safety analysis, two events credit a reactor trip on the variable overpower band setpoint. The band setpoint used in these analyses is 17%. The uncontrolled CEA withdrawal from a low power condition in Section 15.4.1 of the CESSAR FSAR credited this reactor trip. In addition, the CEA Ejection analyses implicitly credited this reactor trip for the purposes of determining that a CEA Ejection at Hot Full power is more limiting than a CEA Ejection at hot zero power. Because the CEA Ejection at hot full power is more limiting, it is presented in CESSAR FSAR Section 15.4.8. The variable overpower band setpoint used in the Safety Analysis (17%) is conservative with the Technical Specification maximum allowable band setpoint of 10%.

The maximum rate at which the variable overpower band setpoint can increase is 11% per minute. For any safety analysis transient crediting the variable overpower band setpoint, this 11% per minute maximum rate of increase has negligible impact on the results. As an example, consider the impact of this rate setpoint on the slower of the two transients discussed above, the uncontrolled CEA withdrawal from a low power condition (Section 15.4.1). From CESSAR-F Figure 15.4.1-2, it can be seen that the core power does not increase appreciably above 0% for the first 15 Seconds. Between 15 and 23.4 seconds (time of trip) core power increases exponentially. During this approximately 10 sec period the maximum increase of the band trip setpoint is (10 sec/60 sec/ min) (11%/min) or 1.8%. As can be seen from Figure 15.4.1-2 the additional amount of time required to increase core power to 18.8% instead of 17% is extremely small due to the exponentially increasing behavior of core power. Because of the more rapid rate of increase of core power for the zero power CEA ejection transient, it is therefore concluded that the rate setpoint of 11% per minute has no adverse impact on the safety analysis.

TABLE 2.2-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. Logarithmic Power Level - High (1)		
a. Startup and Operating	< 0.798% of RATED THERMAL POWER	< 0.895% of RATED THERMAL POWER
b. Shutdown	< 0.798% of RATED THERMAL POWER	< 0.895% of RATED THERMAL POWER
C. Core Protection Calculator System		
1. CEA Calculators	Not Applicable	Not Applicable
2. Core Protection Calculators	Not Applicable	Not Applicable
D. Supplementary Protection System		
Pressurizer Pressure - High	$\leq$ ~~2434~~ 2409 psia	$\leq$ ~~2459~~ 2414 psia
II. RPS LOGIC		
A. Matrix Logic	Not Applicable	Not Applicable
B. Initiation Logic	Not Applicable	Not Applicable
III. RPS ACTUATION DEVICES		
A. Reactor Trip Breakers	Not Applicable	Not Applicable
B. Manual Trip	Not Applicable	Not Applicable



Amendment No. 7
March 31, 1982

C-E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER CORE POWER vs TIME	Figure 15.4.1-2

Question

2. Reactor Coolant System Process Variable LCO

Are the values used for process variable LCOs indicated values from the instrumentation or the actual values in the systems? If they are actual values, please explain how instrument uncertainty is accounted for when determining if an LCO is met or exceeded.

Response

APS's practice is to put indicated values for process parameters in the Technical Specifications. This avoids the need for the operator to provide a correction factor. The indicated values are obtained by applying the appropriate instrument error to the range of initial conditions used in the accident analysis.

Question

3. <u>Moderator Temperature Coefficient</u> (Section 3.1.1.3, page 3/4 1-4)

The Technical Specifications (3.1.1.3 and Figure 3.1-1) permit plant operation in Modes 1 and 2 with a moderator temperature coefficient range of between 0.22×10^{-4} and -3.5×10^{-4}. The single reactor coolant pump rotor seizure with loss of offsite power event was analyzed at full power with a moderator temperature coefficient of a value specified in Figure 3.1-1?

Response

The effect of a slightly positive MTC is negligible since the event causes a very quick reactor trip (0.8 sec). The time of minimum DNBR is 1.4 seconds. The temperature increase during the first 1.4 seconds is approximately $5^{o}F$. This would cause approximately a 2% power increase with an MTC of $+.22 \times 10^{-4}$ during this time period. The increase in heat flux would be a fraction of 1%. Thus, the effect on DNBR would be negligible and would be offset by conservatisms in the analysis. Moreover, COLSS preserves more margin to DNB at lower powers than at full power to account for wider operating bands. This additional COLSS margin would offset the impact of a small power increase during a single reactor coolant pump shaft seizure event initiated from less than full power. Thus, the event analyzed at full power is the worst case.

If the event was analyzed with a $-3.5 \times 10^{-4} \Delta\rho/^{o}F$ MTC at full power the consequences of this event would also be less severe than that analyzed with a 0.0 MTC. The shaft seizure event with a loss of offsite power is a heatup event which with a negative MTC would cause an initial reduction in power prior to reactor trip, thus reducing the potential for fuel damage.

Question

4. <u>Boron Injection Flow Paths</u> (Section 4.1.2.2.b, page 3/4 1-8)

Provide basis for the minimum flow of 26 gpm to the RCS from the boron injection flow path specified in the surveillance requirements.

Response

The basis for this surveillance test is to verify the boron injection flow path. The capacity of each charging pump is 44 gpm at its discharge. Up to 16 gpm of this may be diverted to the Volume Control Tank via the Reactor Coolant Pump Seal Control Bleedoff. Instrument inaccuracies and pump performance uncertainties are limited to 2 gpm during this test. Thus, if 26 gpm are being delivered to the RCS with one charging pump operating, the specified flow path is verified to exist. For two charging pumps operating 68 gpm verifies the operability of the flow path.

For the System 80 natural circulation cooldown analysis net charging flows into the RCS of 28 gpm and 72 gpm for one and two charging pump operation respectively were assumed. Actual charging flowrates of 26 gpm and 68 gpm for one and two pumps have no impact on the cooldown analysis results. As shown in the cooldown analysis, the charging pumps are operated for limited time intervals, as needed. Therefore, the slightly lower flow rates would simply translate to longer pump operating cycles. A review of the analysis has shown that the small increase in charging flow times would still be off of the critical path for cooling down. This increase in charging flow times is less than the time intervals between charging pump operation for the natural ciruclation analysis. Therefore, no additional time is taken for cooldown and no additional condensate is needed. The existing analysis is still valid.

Question

5. <u>Boron Dilution</u> (Section 3.1.2.7, page 3/4 1-16 through 3/4 1-16d).

Provided bases for the monitoring frequencies for boron dilution detection listed in Tables 3.1-1 through 3.1-5.

Response

The basis for establishing the boron concentration monitoring frequencies of Technical Specification 3.1.2.7 is to ensure that the operator, has sufficient time to detect and terminate an inadvertent boron dilution event prior to loss of shutdown margin. Our criteria is that the operator has at least 15 minutes to take action during all modes other than refueling, and 30 minutes to take action during refueling. This is consistent with the criteria of Standard Review Plan (SRP) Section 15.4.6. The monitoring frequencies of Technical Specification Tables 3.1-1 through 3.1-5 ensure that these minimum times are available.

The mathematical model for determining the time to dilute to criticality is given in CESSAR FSAR Section 15.4.6.3. Using this model, the times to criticality supporting Technical Specification Table 3.1-3 ($-3\%\Delta K/K$) are given in the attached Table 5-1. Technical Specification Tables 3.1-1, 3.1-2, 3.1-4 and 3.1-5 were developed in the same manner.

For those periods of time during which no charging pumps are operating, it is prudent to sample the RCS for boron concentration periodically. Appropriate sampling frequencies have been selected to detect the slow events which may occur. Examples of such events might be secondary to primary leakage through steam generator tubes, a water leak entering the refueling pool, or leakage of the iodine removal solution into the shutdown cooling system. Such events may also be detected by other means prior to loss of SHUTDOWN MARGIN. NUREG/CR-2298, Evaluation of Events Involving Unplanned Boron Dilutions in Nuclear Power Plants, gives further examples which have been considered.

Technical Specification Tables 3.1-1 through 3.1-5 were developed for various values of Keff. This was done to give additional operating flexibility as the SHUTDOWN MARGIN specified in Technical Specifications 3.1.1.1 and 3.1.1.2 may be met utilizing various combinations of CEAs and boron. To ensure that the surveillance frequencies are adequate, they have been determined assuming all CEAs are withdrawn (all rods out) and the initial boron concentration is that required to meet the Keff for each Table. This has been done even though it is expected that plant operating procedures may prohibit the achievement of the all rods out configuration in actual practice.

The limiting inadvertent boron dilution event presented in the CESSAR FSAR Section 15.4.6 occurs in Mode 5 with the reactor 2% $\Delta\rho$ subcritical and three charging pumps operating. For this limiting analysis it was assumed that all CEAs, with the exception of the highest worth rod, are inserted and the time to criticality was determined to be 95 minutes. For the Palo Verde Technical Specifications, the times shown in Table 5-1 were determined assuming all CEAs are fully withdrawn (all rods out) and the reactor is being maintained subcritical on boron only. This is more conservative than the FSAR analysis and thus produced some times to criticality which are less than those presented in the FSAR. The assumption that the reactor is being maintained subcritical on boron alone means that the critical boron concentration is higher and will thus be approached more rapidly for a given dilution rate.

Technical Specification Tables 3.1-1 through 3.1-5 will be revised to assume all CEAs are inserted, which is consistent with the CESSAR accident analysis. The revised tables will be available by mid-February, 1985.

Table 5-1

Times to Loss of SHUTDOWN MARGIN, Monitoring Frequencies Required and Time Available for Operator Action as a Function of Operating Charging Pumps and Plant Operational Modes for $0.97 \geq K_{eff} > 0.96$

Number of Operating Charging Pumps	Operational Mode	Time to Loss of Shutdown Margin (Min)	Monitoring Frequency Required (Min)	Time Available for Operator Action (Min)
0	3	---	12 hrs	---
	4	---	12 hrs	---
	5 RCS filled	---	8 hrs	---
	5 RCS partially drained	---	8 hrs	---
	6	---	24 hrs	---
1	3	265	210 (3.5 hrs)	55
	4	279	210 (3.5 hrs)	69
	5 RCS filled	258	210 (3.5 hrs)	48
	5 RCS partially drained	97	60 (1 hr)	37
	6	590	480 (8 hrs)	110
2	3	132	90 (1.5 hrs)	42
	4	139	90 (1.5 hrs)	49
	5 RCS filled	129	90 (1.5 hrs)	39
	5 RCS partially drained	OPERATION NOT ALLOWED*		
	6	295	240 (4 hrs)	55
3	3	88	60 (1 hr)	28
	4	93	60 (1 hr)	33
	5 RCS filled	86	60 (1 hr)	26
	5 RCS partially drained	OPERATION NOT ALLOWED*		
	6	196	120 (2 hrs)	76

* because of insufficient time for the operator actions.

Question

6. RSP/ESF Response Times (Table 3.3-2, page 3/4 3-9 and 3.3-5, page 3/4 3-24 through 3/4 3-26)

   (A) Provide the bases for RPS/ESF response times listed in these tables or refer to the assumptions made in Chapter 15 of FSAR.

   (B) Provide times lines for all the transients discussed in the response to this question.

   (C) Why are the neutron detectors exempt from response time testing?

   (D) Verify that the response time testing procedures include sensor and signal delays.

Response

This question/response was submitted under a separate cover letter dated November 13, 1984 (ANPP-31119).

Question

7. Overpressure Protection System (Section 3.4.8.3, page 3/4 4-32)

Figure 3/4 3.4-2 should be modified to add a curve of Pressure/Temperature limits for RCS cooldown at a rate of 40°F/hour which is used as the basis of the LCO in Section 3.4.8.1.

Response

The 100°F/hr cooldown curve is more limiting than the 40°F/hr cooldown curve.

A 40°F/hr cooldown curve is not recommended on Figure 3/4 3.4-2 for the following reasons. The curve labeled "Isothermal and 100°F/hr Cooldown" shown on Figure 3.4-2 is limiting for the 40°F/hr cooldown condition. The isothermal conditions analyzed are actually from 10°F/hr cooldown to 10°F/hr heatup. The 10°F/hr heatup condition proved to be more limiting than either the 10°F/hr cooldown, 40°F/hr cooldown, or 100°F/hr cooldown. Thus, the isothermal and 100°F/hr cooldown curve shown in Figure 3.4-2 is based on the limiting condition of a 10°F/hr heatup. For better clarity the curve will be relabeled to read "Isothermal to 100°F/hr cooldown".

Question

8. Steam Generator Water Level (Section 3/4.4)

Explain why there is no LCO on the steam generator water level. What assurance is there that the steam generator water level will not exceed the values assumed in the safety analyses?

Response

An LCO on steam generator water level is not necessary since the Chapter 15 and LOCA safety analyses consider the range of steam generator water levels from the low steam generator level trip setpoint to the high steam generator water level trip setpoint. For events in which the value of this parameter would have a significant impact on the event consequences the value of this parameter is selected to maximize the consequences. For events in which the consequences have a negligible sensitivity to this parameter the analysis may assume an arbitrary initial water level within the specified initial condition space.

Question

9. <u>Operability of the Steam Generators</u> (Section 4.4.1.2.3 and 4.4.1.3.2, Page 3/4 4-2 and 3/4 4-4)

These surveillance requirements state that the required steam generator(s) shall be determined operable by verifying the secondary side water level to be 25% of wide range indication at least once per 12 hours. Provide the bases for the 25% steam generator water level.

Response

The 25% level is high enough to provide adequate decay heat removal. This is the initial S/G level assumed in the analyses listed below:

(1) Forced Circulation - 4 RCPs, 2 steam generators taking the RCS from operating conditions to shutdown cooling entry conditions.

(2) Forced Circulation - 2 RCPs, 2 steam generators taking the RCS from operating conditions to shutdown cooling entry conditions.

(3) Natural Circulation, 2 steam generators taking the RCS from operating conditions to shutdown cooling entry conditions.

(4) Natural Circulation, 2 steam generators replacing one shutdown cooling heat exchanger.

Operability of the steam generators was defined by the ability to remove the required amount of heat. The minimum level for operability was defined as the level required to prevent degraded primary to secondary heat transfer. For purposes of this study, the onset of degraded heat transfer was defined as a $1^{o}F$ rise in primary coolant temperature, T_{cold}.

T_{cold} was calculated as a function of overall heat transfer coefficient, heat transfer area, heat flux and secondary temperature. The heat transfer area and heat flux were varied and a plot of percent tube coverage versus differential temperature ($T_{cold} - T_{secondary}$) was generated. The $1^{o}F$ rise in T_{cold} criteria was applied to this plot and a corresponding value of tube coverage was found.

The values for percent tube coverage varied from 40% for the two natural circulation cases (Cases 3 and 4) to 65% for the limiting forced circulation case (Case 1 with four RCPs running). The 65% tube coverage converts to 23% wide range level. Two percent instrument error is added to arrive at the Technical Specification value of 25%.

Question

10. <u>Auxiliary Feedwater System</u> (Section 3.7.1.2, page 3/4 7-4)

A. Section 4.7.1.2 should be modified to include a surveillance test of each AFW pump to verify the required pump head and flow rate.

B. Provide a matrix of Chapter 15 events of the FSAR indicating the effects of a reduction in auxiliary feedwater flow from 875 gpm to 750 gpm, and an auxiliary feedwater delay time and lockout time of 45 seconds/30seconds (without offsite power available/with offsite power available).

Response

A. The responses to this request has been previously submitted and incorporated into Technical Specification 3.7.1.2. This information has been reviewed and approved by RSB for incorporation into the PVNGS Technical Specifications.

B. The matrix of Chapter 15 events requested is being provided as Table 1.9-4 of the PVNGS FSAR change package regarding changes to the auxiliary feedwater system which is being submitted under separate cover.

Question

11. Auxiliary Pressurizer Spray System (Section 3/4.4)

The current Palo Verde Technical Specifications do not include a section to address limiting conditions for operation and surveillance requirements on the Auxiliary Pressurizer Spray System (APSS). It is the staff's understanding that the APSS is required for RCS depressurization during plant shutdown per the requirement of the BTP RSB 5-1 (i.e., plant cooldown using only safety-related equipment) and during the post-SGTR operation. Does the applicant intend to develop appropriate technical specifications for the APSS? If not, provide the technical basis for not doing so.

Response

A. The Technical Specification has been developed, provided and incorporated into the PVNGS proof and review Technical Specifications. This Technical Specification has been reviewed and approved by RSB.

B. The Technical Specification Basis is the following:

3/4.4.3.2 Auxiliary Spray Valves

The pressurizer spray is required to depressurize the RCS by cooling the pressurizer steam space to permit the plant to enter shutdown cooling. The auxiliary pressurizer spray is required during those periods when normal pressurizer spray is not available, such as during natural circulation and during the later stages of a normal RCS cooldown. The auxiliary pressurizer spray also distributes boron to the pressurizer when normal pressurizer spray is not available. Use of the auxiliary pressurizer spray is required during the recovery from a steam generator tube rupture and a small loss of coolant accident if normal pressurizer spray is unavailable.

Question

12. Cold Shutdown with Loops Filled (Section 3.4.1.4.1, Page 3.4 4-5)

The limiting condition for operation specified in this section will permit the plant to operate in Mode 5 with the reactor coolant loops filled, only one SDCS loop is in operation, plus two steam generators having 25% water level. Explain how the plant could be maintained in Mode 5 assuming a failure of the operating SDCS loop. Verify that sufficient natural circulation could be achieved during Mode 5.

Response

The requirement is that adequate core heat removal be maintained, not that natural ciruclation be established in Mode 5. As the upper temperature limit of Mode 5 is 210°F, steam cannot be drawn off the steam generators until the plant heats up to Mode 4. The length of time after reactor shutdown determines the time at which enough decay heat has been added to raise the reactor coolant system (RCS) temperature sufficiently to permit opening the atmospheric dump valves (ADVs) to remove heat. Until sufficient heat to permit drawing steam off the steam generators is reached, there is no real problem with core heat removal.

There is sufficient time following a loss of shutdown cooling flow for the operator to take action to initiate auxiliary feedwater and open the atmospheric dump valves prior to the plant exceeding Mode 4 conditions. Operations of this nature have been accepted as alternate success paths for core and RCS heat removal on previous plants.

Question

13. Safety Valves (Section 3.4.2.1, page 3/4 4-7)

Section 3.4.2.1.b permits that the provisions of Specification 3.0.4 may be suspended for up to 12 hours for entering into and during operation in Mode 4. Provide the basis for this Technical Specification provision.

Response

The way the original (STS) Technical Specification was written, these valves needed to be tested just after we entered into Mode 4. We need to be at a desired pressure and temperature in Mode 4 in order to perform this test per our manufacturer. Also, we will need time to set-up test equipment and test these valves once we get into Mode 4. The 12 hours will allow us time to perform this test at the appropriate pressure/temperature conditions with the correct test equipment set-up. The 12 hours also limits the time we can be in Mode 4 before performing this test. This Response has been discussed and approved by RSB during our meetings in October, 1984.

Question

14. Pressure/Temperature Limits (Section 3.4.8.1, page 3/4 4-28)

Verify and modify the temperature limits indicated in this section consistent with Figure 3/4 3.4-2.

Response

See Response to RSB Question 7.

Question

15. Reactor Coolant System Vents (Section 3.4)

The current Palo Verde Technical Specifications do not include a section to address limiting conditions for operation and surveillance requirements on the Reactor Coolant System Vents. It is the staff's understanding that the applicant takes credit for RCS vents to depressurize the RCS during shutdown per BTP RSB 5-1. Does the applicant intend to develop appropriate Technical Specification for the RCS vents. If not, provide the technical basis for not doing so.

Response

APS has submitted a Technical Specification (3/4.4.10) for the Reactor Coolant Vent System. This Technical Specification was reviewed by RSB and incorporated into the PVNGS proof and review copy of the Technical Specifications.

Question

16. Atmospheric Steam Dump Values (Section 3/4.7)

The current Palo Verde Technical Specifications do not include a section to address limiting conditions for operation and surveillance requirfements on the Atmospheric Steam Dump Valves (ADVs).

Since the ADVs are required during initial phase of plant shutdown per the requirements of the BTP RSB 5-1 (i.e., plant cooldown using only safety-related equipment), and we understand your FSAR Chapter 15 steam generator tube rupture analysis takes credit for these components, explain what assurances exist in the plant that these components will always be operable in accordance with the assumptions made in the safety analyses.

Similarly, the Staff and Commission concluded it was acceptable to defer a decision on the need to install PORVs in your plant based, in part, on the CE PRA study performed for your plant. This PRA placed high reliability on the availability of the ADVs to affect decay heat removal. It is the belief of the staff that the ADVs should have Technical Specifications to assure their operability and availability. If you do not propose Technical Specifications for the ADVs, then please provide the technical basis for not providing Technical Specifications, and address how the assurances you are providing are consistent with the reliability assumptions made in your PRA.

Response

APS has submitted a Technical Specification (3/4.3.7.1.6) for the Atmospheric Steam Dump Valves. This Technical Specification was reviewed by RSB and incorporated into the PVNGS proof and review copy of the Technical Specification.

Question

17. Safety Injection Tanks (Section 3.5.1, Page 3/4 5-1)

Section 3/4 5.1 describes the modes of operation for the safety injection tanks. The basis for this item implies that the values in the Technical Specification were chosen for compliance with the accident analyses. Address why there are no specifications for the coolant temperature in SIT. Otherwise, justify why the SIT coolant temperature assumed in the ECCS analyses bounds the maximum temperature the SIT could attain.

Response

The LOCA analysis assumes a temperature for the Safety Injection Tanks (SIT) of 120°F, because for these analyses a higher temperature is more adverse. The temperature of 120°F is assumed to be the maximum, since this is the limit on containment air temperature specified in Technical Specification 3/4.6.1.5.

Question

18. Special Test Exceptions, Reactor Coolant Loops (Section 3/4.10.3 page 3/4 10-3)

This Technical Specification permits plant operation up to 5% thermal power on fission heat without any reactor coolant pumps operating for startup or physics test. What safety analyses have been conbducted that demonstrate that transients or accidents initiated from this operating condition would be acceptable for Palo Verde Units? Both the steady state and transient reactor coolant system temperature profiles, margin to saturation, core DNBR, and thermal-hydraulic stability should be assessed. The acceptability of the reactor protective system setpoints during various transients and accidents initiated from this condition must also be justified.

Response

This Special Test Exception is not intended to be used to allow operation without any reactor coolant pumps (RCPs) operating. It is required in order to allow certain low power physics tests to be conducted which require both that the reactor be critical and that the RCS temperatures be below those at which it is permissible to operate all four RCPs. This Technical Specification has been revised to include the requirement that at least one RCP be operable in each reactor coolant loop for this test exception to be allowed (See attached revised Technical Specification).

Considering this Special Test Exception is typically invoked only during the initial core startup for low power testing for a short period of time, usually less than a week, the occurrence of an accident during this plant configuration is of such low probability that it is not considered credible. A review and evaluation of plant responses to transients analyzed for CESSAR Chapter 15 shows that for anticipated operational occurrences this plant configuration is acceptable for the following reasons:

(a) Limiting plant operation to 5% power assures adequate thermal margin to preclude fuel damage following a loss of forced circulation.

(b) Requiring plant operation with at least 1 pump per loop and requiring reduction of reactor trip setpoints to 20% power assures adequate thermal margin to preclude fuel damage during power increases casued by any anticipated operational occurrence.

(c) Limiting power to 5% assures that RCS heatup/overpressurization events will be less severe than these presented in CESSAR & PVNGS FSAR Chapter 15.

SPECIAL TEST EXCEPTIONS

3/4.10.3 REACTOR COOLANT LOOPS

DRAFT

LIMITING CONDITION FOR OPERATION

3.10.3 The limitations of Specification 3.4.1.1 and noted requirements of Tables 2.2-1 and 3.3-1 may be suspended during the performance of startup and PHYSICS TESTS, provided:

a. The THERMAL POWER does not exceed 5% of RATED THERMAL POWER, and

b. The reactor trip setpoints of the OPERABLE power level channels are set at less than or equal to 20% of RATED THERMAL POWER.

c. Both reactor coolant loops, and at least one reactor coolant pump in each loop, ~~shall be~~ are in operation.

APPLICABILITY: During STARTUP and PHYSICS TESTS.

lc

ACTION:

With the THERMAL POWER greater than 5% of RATED THERMAL POWER or with if less than the above required reactor coolant loops is in operation and circulating reactor coolant, immediately trip the reactor.

SURVEILLANCE REQUIREMENTS

4.10.3.1 The THERMAL POWER shall be determined to be less than or equal to 5% of RATED THERMAL POWER at least once per hour during startup and PHYSICS TESTS.

4.10.3.2 Each logarithmic and variable overpower level neutron flux monitoring channel shall be subjected to a CHANNEL FUNCTIONAL TEST within 12 hours prior to initiating startup and PHYSICS TESTS.

4.10.3.3 The above required reactor coolant loops shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

Question

19. <u>Safety Valves</u> (Section 3.7.1.1, Page 3/4 7-1)

Section 3.7.1.1.b indicates that operation in Mode 3 and 4 may proceed with one reactor coolant loop and associated steam generator in operation, provided that there are no more than four inoperable main steam line code safety valves associated with the operating steam generator. Describe any safety analysis performed to support the above plant operation.

Response

Operation in Mode 1 is permitted with up to four inoperable MSSVs per steam generator by this Technical Specification provided reactor power is limited as shown in Table 3.7-2. Operation in Modes 3 and 4 is less limiting than operation in Mode 1.

The main steam safety valves (MSSVs) limit secondary system pressure to within 110% (1397 psia) of the design pressure (1270 psia) during the most severe anticipated operational transient. For design purposes, a turbine trip (without reactor trip or cutback) from RATED THERMAL POWER with a coincident loss of condenser heat sink (i.e., no steam bypass) is assumed. The combined relieving capacity of the pressurizer safety valves, and the heat removal capacity of the MSSVs, is sufficient to maintain the Reactor Coolant System pressure below NRC acceptance criteria (120% of design pressure for large feedwater line breaks and 110% of design pressure for all other events).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section 111 of the ASME boiler and Pressure Vessel Code, 1974 Edition. The total relieving capacity of all twenty MSSVs at 110% of system design pressure (adjusted for 50 psi pressure drop to valves inlet) is 19.44×10^6 lbm/hr. This capacity is less then the total rated capacity of 19.53×10^6 given in Table 3.7-1 as the MSSVs are operating at an inlet pressure below rated conditions. At these same secondary pressure conditions, the total steam flow at 102% (2% uncertainity) of 3817 MWt (RATED THERMAL POWER plus 17 MWt pump heat input) is 17.83×10^6 lbm/hr. The ratio of this total steam flow to the total capacity of 109.2%.

STARTUP and/or POWER OPERATION is allowable with MSSVs inoperable if the maximum allowable power level is reduced to a value equal to the product of the ratio of the number of MSSVs available per steam generator to the total number of MSSVs per steam generator with the ratio of total steam flow to available relieving capacity.

$$\text{Allowable Power Level} = \frac{10-M}{10} \times 109.2$$

Although the variable high power reactor trip is not relied on for the limiting overpressure events, the ceiling on this trip is also reduced to an amount over the allowable power level equal to the BAND given for this trip in Table 2.2.1.

SP = Allowable Power Level + 9.8

where:

SP = reduced reactor trip setpoint in percent of RATED THERMAL POWER. This is the ratio of the available relieving capacity of the total steam flow at rated power.

10 = total number of main steam safety valves for one steam generator.

N = number of inoperable main steam safety valves on the steam generator with the greater number of inoperable valves.

109.2 = ratio of main steam safety valve relieving capacity at 110% steam generator design pressure to calculated steam flow rate at 100% plant power +2% uncertainity (see above text).

9.8 = BAND between the maximum thermal power and the variable overpower trip setpoint ceiling.

Question

20. <u>ECCS Subsystems T_{cold} Greater than or Equal to 350°F</u> (Pages 3/4 5-5 and 3/4 5-6)

A. Describe how 277 ± 5 gpm per injection point (HPSI System - Single Pump) relates to the information in CESSAR FSAR Table 6.3.3.3-1.

B. For what pressure is the new value of 816 gpm for three injection points referenced?

C. What injection flow was used in the LOCA analysis of CESSAR Chapter 6.3?

D. Describe how 4900 gpm for the LPSI flow relates to the information in CESSAR FSAR Table 6.3.3.3-1.

Response

A. CESSAR FSAR Table 6.3.3.3-1 provides the minimum safety injection flow delivered to the RCS. The case presented is for failure of one emergency generator to start following a loss of offsite power. In this case only one LPSI pump and one HPSI pump are delivering flow to the RCS. The value of 277 ± 5 gpm, given in the Technical Specification, is the flow per cold leg injection point at 0 psig. Table 6.3.3.3-1 assumes 250 gpm per injection point (A_1, A_2, B_1, B_2) from one HPSI pump at an RCS pressure of 0 psig. An indicated flow rate of 277 ± 5 gpm will ensure that delivered flow rate is greater than or equal to 250 gpm.

B. The HPSI Technical Specification of 816 gpm for the sum of the three lowest legs is at 0 psig.

C. The injection flow used in the LOCA analysis is in Table 6.3.3.3-1, however, location of the break may cause loss of one of the injection legs. For example if the break was at the A_1 injection point then only the flow in A_2, B_1 and B_2 would be available.

D. Table 6.3.3.3-1 provides the minimum flow delivered to the RCS by the safety injection system. The case presented in the table is for loss of an emergency generator following loss of offsite power resulting in only one HPSI pump and one LPSI pump available. In the injection mode one LPSI pump will deliver to injection points A_1 and A_2 (as in Table 6.3.3.3-1) and the other LPSI pump to injection points B_1 and B_2.

Table 6.3.3.3-1 assumes 4214 gpm from one LPSI pump delivered to points A_1 and A_2 at an RCS pressure of 0 psig. The remaining flow of 500 gpm in Table 6.3.3-1 assumed delivered to points A_1 and A_2 is from the available HPSI pump. The value given in surveillance requirement 4.5.2.h for LPSI pump flow of 4900 ± 100 gpm is at 0 psig and is split between two injection points. This total flow exceeds the CESSAR required flow of 4214 gpm even with the measurement uncertainty.

[illegible]