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FACIL:STN-50-528 Palo Verde Nuclear Station, Unit 1, Arizona Publi 05000528
STN-50-529 Palo Verde Nuclear Station, Unit 2, Arizona Publi 05000529
STN-50-530 Palo Verde Nuclear Station, Unit 3, Arizona Publi 05000530
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SUBJECT: Discusses telecon conversation between Arizona Public Svc Company & NRC on 920130 & APS response supporting setpoint tolerance changes for PVNGS PSVs & MSSVs enclosed.

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EXECUTIVE VICE PRESIDENT
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102-02159-WFC/DAF
May 27, 1992

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Reference: Letter 161-03587-WFC/JST, dated November 13, 1990, from W. F. Conway, APS, to NRC, "Proposed Technical Specification Amendments to Sections 3/4.3.1, 3/4.4.2, 3/4.7.1, and 3/4.7.2"

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Proposed Setpoint Tolerance Changes for PSVs and MSSVs
File: 92-056-026

During a telephone conference between Arizona Public Service Company (APS) and the NRC on January 30, 1992, the NRC identified questions regarding the referenced Technical Specification amendments. Provided in the enclosure is APS' response to these questions.

If you should have any questions, please contact Thomas R. Bradish of my staff at (602) 393-5421.

Sincerely,

WFConway

WFC/DAF/pmm

Enclosure

cc: J. B. Martin
D. H. Coe
A. C. Gehr
A. H. Gutterman

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ENCLOSURE

APS RESPONSE SUPPORTING PROPOSED SETPOINT TOLERANCE CHANGES FOR PVNGS PSVs AND MSSVs

PROPOSED SETPOINT TOLERANCE CHANGES FOR PSVs AND MSSVs

In response to the issues discussed by the NRC (Reference 1--see page 14 for list of References) and Arizona Public Service Company (APS) with respect to the PSV/MSSV tolerance Technical Specification change requested (Reference 2) and a telephone conference on January 30, 1992, APS submits the following responses to NRC questions (paraphrased from the telephone conference):

NRC QUESTION No. 1:

Discuss conservatisms in modeling the Loss of Condenser Vacuum (LOCV) event, including assumptions and margins involved.

APS RESPONSE TO No. 1:

The response to this question is presented in three parts, namely: conservatisms in the LOCV analysis, margin for Reactor Coolant System (RCS) pressure for an LOCV event at normal operating conditions, and probability risk assessment of an LOCV event.

CONSERVATISMS IN THE LOCV ANALYSIS

There are a number of conservative assumptions in the LOCV analysis. Of all the analyzed events, the LOCV analysis is the bounding pressurization event and results in the highest calculated RCS pressure. These conservative assumptions are:

1. Feedwater and steam flow to the turbine are assumed to ramp down to zero lbm/sec in 0.1 second. This is essentially an instantaneous reduction in main feedwater flow. This assumption is very conservative. For an actual LOCV event, a more realistic modeling of the feedwater rampdown is approximately 18 seconds. This would result in lower peak pressures since the colder auxiliary feedwater (AFW) flow decreases the secondary side temperature during this interval. A reduced secondary side temperature dissipates more heat from the primary side thereby reducing both the primary and secondary side pressures. This is also true for steam flow rampdown.

2. In the analysis, all the safety valves (4 PSVs and 20 MSSVs) are assumed to open at the maximum setpoint tolerance of +3%. In an actual LOCV event, only some MSSVs would equal or exceed this limit. (See the actual PVNGS MSSV setpoint tolerance data shown on page 7). Note that since there are 20 MSSVs, it is reasonable to expect some will open below +3% and some could even open below the setpoint. Any valve that opens below the +3% tolerance value will have a mitigating effect (i.e., reducing peak pressure) on the transient. The PSVs and MSSVs will be set to ± 1% of their set pressure when found out of this range.

3. The analysis assumes a high pressurizer pressure trip (HPPT) setpoint of 2450 psia. This includes a 30 psi uncertainty due to a wire defect in the pressurizer transducers (Reference 3) which affects the monitoring of RCS pressure. During the recent Unit 1 refueling outage, this wire defect was corrected in Unit 1. Corrections have already been made for Units 2 and 3. Since this error was corrected, the 30 psi uncertainty can be removed and the HPPT setpoint of 2420 psia can be used in the analysis. This would reduce peak pressure.

   Recent tests of the instrumentation have found that the HPPT setpoint is actually within a few pounds of the nominal setpoint of 2383 psia. This would result in a further decrease of RCS peak pressure for the LOCV event.

   The HPPT response time has been reduced from 1.15 seconds to 0.5 second. The reduction in the response time reduces the RCS heatup during an LOCV event. Surveillance tests for all 3 units have shown that this trip response time is consistently less than 0.3 second. Therefore, the assumed response time of 0.5 second used in Reference 2 is conservative. Using the 0.3 second value in the LOCV analysis would further reduce the RCS peak pressure.

4. The pressurizer level and pressure control systems are assumed to be in a manual mode and are not available during the LOCV event. This is conservative in that this condition maximizes the rate of RCS pressure increase during the event. In an actual LOCV event the pressurizer sprays will be activated thereby reducing the peak pressure.

5. The initial pressurizer level is set at 488.8 ft^3 in the analysis which is conservatively lower than the minimum programmed pressurizer level setpoint of 560 ft^3 at low power. For CE System 80 Units, ABB/CE evaluated the programmed pressurizer setpoint as follows. The pressurizer level is programmed to ramp down from 50% to 25% of the total pressurizer volume between 100% and 15% core power. Thus at 15% power, the initial steady state volume of the pressurizer is (0.25x1800+38.8) ft^3, i.e., 488.8 ft^3 (where 1800 ft^3 is the pressurizer volume and 38.8 ft^3 is the surge line volume). At 100% power this yields 938.8 ft^3. Use of a lower initial fluid level delays the high pressurizer trip and thus maximizes the RCS pressure during the event. Thus using the 488.8 ft^3 at 100% power is conservative. Note that this number is close to the Technical Specification (3.4.3.1) minimum of 463.8 (425+38.8) ft^3 for the minimum steady state pressurizer level.

6. In the analysis, the Reactor Power Cutback System (RPCS) and the Steam Bypass Control System (SBCS) are assumed to be in the manual mode (unavailable during the LOCV event, since they are not safety grade systems). The unavailability of the SBCS minimizes the amount of cooling while the unavailability of the RPCS maximizes the heat generation in the core. The RPCS is designed to drop control element assembly regulating group(s) 5, or 4 and 5 (depending on core life, power level, etc.) in reaction to a load rejection thereby reducing the reactor power. The units normally operate with these systems available. Operation of the SBCS together with RPCS is

designed to reduce reactor power without tripping the units. If these systems are in automatic mode and credited during the analysis, RCS pressure will not even reach the HPPT setpoint.

7. The Moderator Temperature Coefficient (MTC) is assumed to be most positive (or 0.0% delta rho/°F). This is conservative since a positive MTC minimizes the core power decrease during an LOCV event when RCS temperature increases.

8. Other conservative assumptions concerning the reactor physics parameters are noted below.[1]

   (a) The fuel temperature coefficient is assumed to be least negative (Beginning of Cycle [BOC] conditions). This is conservative because it inhibits the core power rise the least.

   (b) The BOC generic kinetic parameters are used. This maximizes the heat flux after a reactor trip which maximizes the RCS pressure. In general, the cycle-specific kinetic parameters are smaller than generic values. Thus the generic values are more conservative.

   (c) The scram worth used assumes the worst rod is stuck full out. This is conservative because it reduces the negative reactivity inserted by the rods and hence results in a slower power decrease.

<u>LOCV EVENT FROM NORMAL OPERATING CONDITIONS</u>

In order to further evaluate the margin for RCS peak pressure from normal operating conditions, a CESEC case was simulated for an LOCV event from these conditions. The plant operates at this level most of the time. The parameters selected for the key variables are as follows:

initial pressurizer pressure	= 2250 psia
initial pressurizer level	= 938.8 ft^3
HPPT setpoint	= 2383 psia
reactor coolant pump, flowrate/pump	= 106462 lbm/sec
HPPT delay setpoint	= 0.3 secs
Spray on: continuous	= 1.5 gpm
proportional	= 375 gpm
steam generator pressure	= 1070 psia
initial steam generator mass	= 170072 lbm

[1] It is estimated that removal of conservatisms in item 8 will reduce RCS peak pressure by approximately 2 psi.

Additionally, the conservatisms that are generally used in an LOCV analysis for parameters such as MTC, fuel temperature coefficient, kinetic parameters, gap conductance, etc., were not included. The feedwater flow ramps down to 5% normal flow rate in 18 seconds, as was discussed in item 1 above. The RPCB and SBCS are again set in manual and are not operational.

The CESEC run with the above parameters resulted in a peak RCS pressure of 2650.5 psia at 6.8 seconds. Thus the RCS peak pressure reduced by about 90 psi for an LOCV event that is more likely to occur from nominal operating conditions than by setting all operating conditions to values that drive the RCS to its worst peak pressure. Such a limiting condition is highly improbable at best.

PROBABILITY RISK ASSESSMENT OF AN LOCV EVENT

An analysis was performed to estimate the frequency of an LOCV event that results in RCS pressure exceeding 110% of design pressure. The analysis conservatively assumed that a LOCV event would result in RCS pressure exceeding 110% of design pressure if (1) the loss of condenser vacuum is sudden and complete; (2) the PSVs operate as unfavorably as is assumed in the Technical Specification change (which assumes that all PSVs open at 103% of the setpoint); and (3) the RPCB and SBCS do not operate. The analysis described above shows that there are other conservatisms in the model. Therefore, it is conservative to assume that these three conditions together would necessarily result in RCS pressure exceeding 110% of the design pressure.

The frequency of these three conditions occurring simultaneously is 2.8E-5 events per year. This frequency will not increase if the Technical Specification change request is approved since PVNGS will continue to adjust the set pressure whenever the PSV setpoint is determined to be outside that band. (See Reference 4).

This frequency is judged to be acceptable since:

1) The probability that the combination of initial plant conditions and trip parameters being as unfavorable as is assumed in the licensing analysis is very low. Therefore, only a small fraction of these events would result in peak RCS pressures approaching 110% of the design pressure.

2) These events are negligible contributors to the core damage frequency.

3) The ASME Code required design margins assure that there is a large margin between the design pressure and the ultimate capacity of the system.

NRC QUESTION No. 2:

Why is it acceptable to remove some of these conservatisms?

APS RESPONSE TO No. 2:

The proposed Technical Specification change would add a conservative assumption for safety valve setpoints and reduce the conservatism in HPPT response time. This will permit Technical Specification setpoints to be relaxed and to be made consistent with the provisions of the ASME OM-1 code. This will require the Technical Specification requirement for HPPT response time to be made more stringent as proposed in Reference 2.

The only other conservative assumptions that are being made less conservative are the surge line friction form loss factor and the PSVs opening to 99% of the nominal area opening at the setpoint plus 3%. The change in friction form loss factor has been justified for PVNGS Units by ABB/CE.

The increase in assumed effective opening area of the PSVs was based on Reference 5. Reference 1 questioned the PSV assumption based on consideration of valve opening times. Approximately 20 milliseconds, referred to in Reference 1, is the "simmer time" for rated lift after the inlet "sees" the pressure. It is not presently possible to model the delay in CESEC (Reference 6) directly. Referring to the CESEC output for 0.02 seconds (i.e., 20 milliseconds), the difference in pressure is less than 2 psi. Thus if this 18 milliseconds of simmer time were to be modelled explicitly in CESEC, the peak pressure using a rate of 100 psi/sec will increase the pressure by less than 2 psi. In other words, the RCS peak pressure for the LOCV event presented in Reference 2 will be less than 2742.9 psia.

This conclusion can also be reached from Figure 1[2] (attached) which is a plot of RCS pressure versus time for the LOCV event. From this figure, the maximum slope of pressure increase before a reactor trip is less than 100 psi/sec. Reference 1 predicted that the peak will go up by about 5.5 psi. Regarding the 18 millisecond interval, ABB/CE has stated that "if the short time interval were accounted for, it is expected that the calculated peak RCS pressure reported in the safety analysis would increase by less than 5 psi."

In view of the number of conservatisms in the analysis listed above, a 2 to 5.5 psi nonconservatism is more than compensated for. Regardless of which approach is taken, the result is that the peak RCS pressure remains below the acceptance criteria of 2750 psia. This conclusion is also supported by ABB/CE (Reference 7) which states:

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[2] The RCS pressure plotted here does not include the pressure differential between the cold leg at the safety injection and the surge line which is usually around 56 psia. This parameter is printed separately in CESEC output at the users request.

C-E Nuclear Licensing has consulted with the technical staffs of Plant Engineering Services, which authored the Reference,[3] and Fuel Engineering, which performed a technical review of the safety analysis that supports the proposed Technical Specification change. It is our opinion that the use of the instantaneous PSV opening model in the safety analysis to support the PVNGS Technical Specification change is reasonable.

As modeled in the safety analysis, the PSV is assumed to open to 99% of its full open position at the opening pressure setpoint plus the maximum allowable tolerance. The quick-opening behavior to the full open position is consistent with the test results provided in the Reference. The average time interval for the valve to reach its full open position is very short. If this short time interval were accounted for, it is expected that the calculated peak RCS pressure reported in the safety analysis would increase by less than 5 psi.

A review of other analysis inputs confirms that there is sufficient conservatism in other inputs such that the peak RCS pressure reported in the safety analysis supporting the Technical Specification change remains bounding. In particular, the supporting safety analysis assumes that the main feedwater flow ramps down from its initial 100% value to 0% in less than 0.1 seconds. In reality, the feedwater rampdown time is about 18 seconds. If this conservatism were credited in the safety analysis, it would more than compensate for a 5 psi increase if a PSV valve opening model with a short opening time were used. Thus it is our engineering judgement that the peak RCS pressure reported in support of the Technical Specification change remains bounding.

Therefore, the reduction of these conservatisms is technically justified and is not of sufficient magnitude to affect the acceptability of the analysis.

NRC QUESTION No. 3:

What does APS plan to do in the future regarding resolving the valve problems?

APS RESPONSE TO No. 3:

PVNGS Engineering is trending the PSV and MSSV performance during plant operation and all offsite testing and rework activities. During plant operation, trending is accomplished by a monthly review of each valve in all three units to determine seat leakage occurrence and by monitoring valves that are leaking (mainly MSSVs). PVNGS is also developing a preventive maintenance program for these valves which will remove and replace two PSVs and ten MSSVs every other refueling outage. Engineering continues to review new industry data on safety valve problems to determine if there is any impact to the PVNGS root cause of failure program. PVNGS Engineering is also

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[3] Listed as Reference 5 to this enclosure.

currently conducting a maintenance program to rework the MSSVs and the PSVs. This program, which started during the Unit 2 1991 refueling outage and will be finished during the Unit 3 1993 refueling outage, directs the removal of all the MSSVs and PSVs from the units. The valves are tested at an offsite test facility under the exact PVNGS operating conditions (proper temperature profiles) followed by disassembly, inspection, and reassembly of all valves. This is considered more reliable than the previously used "TREVITEST" method. The "TREVITEST" (in-situ) testing at PVNGS uses a load cell and a strip chart recorder to determine when the valve lifts. The actual system pressure and force required to lift the valve (read from the strip chart recorder) are combined to determine the lift setpoint. Since the test pressure relies on several indications (system pressure, load cell, strip chart recorder and operator strip chart reading accuracy), the instrument uncertainties of this method are much greater than the testing performed at the offsite test facility.

The MSSVs and PSVs at PVNGS continue to drift beyond the current setpoint tolerances. This was evidenced again by the recent Unit 1 surveillance testing results which determined that 14 out of 20 MSSVs and 2 of 4 PSVs as-found relief settings were out of the tolerance limits specified in the Technical Specifications. Reference 8 provides a detailed discussion and assessment of this event.

NRC QUESTION No. 4:

Discuss the Root Cause Program for the safety valves at PVNGS.

APS RESPONSE TO No. 4:

The following is a list of APS actions that have been or will be taken with respect to the root cause program at PVNGS:

1. The Engineering group at PVNGS has developed a program which is trending the PSV and MSSV performance. Since 1987, the "TREVITEST" equipment has been used for set pressure verification. The following matrix summarizes the setpoint tolerance data for PVNGS, indicating the number of valves found between the noted tolerances:

MSSV SETPOINT TOLERANCE DATA			
Total Tested	>3% Tolerance	>2% and <3% Tolerance	>1% and <2% Tolerance
Unit 1 60	5	9	14
Unit 2 100	3	9	26
Unit 3 62	1	4	12

PSV SETPOINT TOLERANCE DATA			
Total Tested	>3% Tolerance	>2% and <3% Tolerance	>1% and <2% Tolerance
Unit 1 11	0	3	3
Unit 2 8	0	3	3
Unit 3 4	2	0	0

It should be noted that the differences between the unit totals and the number of valves with the above tolerances represent those valves whose opening pressure was below +1%. This is not a concern for the LOCV event since this results in earlier event mitigation. In addition, PVNGS started offsite testing in the fall of 1991 and will not be able to show sufficient history of set pressure drift until the fall of 1993 when Unit 2 will be retested.

2. APS has reviewed and continues to review the offsite testing procedures from Wyle Laboratories, Dresser, and Westinghouse. These reviews, including a review of testing procedures from other utilities, have resulted in a revision to the PVNGS offsite testing procedure in order to change valve seat leakage requirements. The new test instructions require PSVs and MSSVs to be seat leakage tested with steam at 93% of the set pressure instead of 90%. This will reduce the possibility of challenging the relief valve. Using the PSVs as an example, the following pressure characteristics are noted:

<u>2750 psia</u>
maximum overpressure allowed
on system (10% accumulation)

<u>2500 psia</u>
valve set pressure and
system design pressure

<u>2375 psia</u>
valve closing pressure
(95% of set pressure)

250 psia operating range

<u>2325 psia</u>
seat tightening pressure
(93% of set pressure)

seat leakage range
(valves have zero seat leakage
for pressures < 2325 psia)

<u>2250 psia</u>
operating pressure
(90% of set pressure)

From the diagram shown on the previous page, it is clear that if the operating pressure is increased above the normal operating pressure of 2250 psia, the operating range of 250 psi would be reduced. In addition, if the seat leakage test was performed at less than 2325 psia, then the seat leakage range would be reduced as well. Both of these actions increase the potential for seat leakage which over time will deteriorate the seating surfaces. If not corrected, the disc seat will erode and the valve lift pressure will become erratic due to the varying seat area.

APS has verified for Units 1 and 2 (Unit 3 to be verified in the fall of 1992) that the valves have an operating range (during offsite testing) within the requirements given in the above example. Therefore, the potential for reduced disc seat force has been lessened for these valves.

In addition, PVNGS valves are now tested with more accurate operating temperature profiles than in previous test methodology. Seat leakage testing with nitrogen has been eliminated as PVNGS now requires these valves to be tested with steam only. Listed below are further improvements to PVNGS offsite testing:

* The validation test now requires that the valves shall not exhibit a continuous increase or decrease in set pressure such that differences between the highest and the lowest opening test exceeds 1.5% of the valve's nameplate set pressure. This assures that any trends in the three setpoint openings used in the verification test will be recognized.

* If the valve fails the seat leakage test, the valve may undergo a "jack and lap" process.[4] A retest, consisting of a minimum of three pop tests within the setpoint tolerance must be performed after each jack and lap. Prior to this change, procedures involved a jack and lap process with no retesting requirements.

* No attempt will be made to adjust blowdown rings during functional testing. This will eliminate ring adjustments without reverifying the setpoint as this has been identified as a frequent oversight within the industry.

* The valves are transported with the valve stem in the vertical position and never in the horizontal position. Transportation shock has been reduced to a minimum by transporting the valves on air-ride trailers.

3. APS has reviewed testing procedures and data from other utilities with the same model valves (Duke Power, Entergy, ANO, SCE, and PG&E). PVNGS Engineering participates in a monthly information sharing with these utilities to discuss safety valve set pressure drift problems and review actions being taken.

[4]The jack and lap process involves a quick disassembly of the valve and a cleaning of the seating surfaces.

4. The temperature profiles used are within 10°F of the actual data currently being taken in Unit 2. Prior to offsite testing, the temperature profiles used were not consistent with actual operating conditions. A temporary modification was installed in the Unit 2 PSVs for additional data collection. This modification installed thermocouples and strain gauges at various locations on each of the 4 valves for valve body and spring temperature monitoring to determine if abnormal forces exist and if stresses are within the vendor's limits. The data collection will be completed by June 1993. The analysis is ongoing to provide a more realistic temperature profile for offsite testing. Preliminary indications show that the actual temperature profiles are within a very small temperature range (10°F). This 10°F should not have an impact on valve setpoints. Once the testing and analysis is completed, offsite testing procedures will be revised as required and a report will be issued.

5. NRC Information Notices related to PWR relief valve concerns as well as INPO O&M reminders, SERs, and SOERs were reviewed and lessons learned incorporated into PVNGS offsite test procedures during 1991. These industry documents discussed and recommended actions on issues such as temperature profiling, valve body stresses, blowdown ring settings, etc. These documents include:

IN 85-05	NUREG 3939	SER 82-10	SER 86-25
IN 86-56	O&MR 0207	SER 82-50	SER 82-06
IN 86-92	SER 80-08	SER 82-73	
IN 88-68	SER 80-29	SER 84-84	
IN 89-90 & Supp 1	SER 81-10	SER 84-58	
IN 91-74	SER 82-05	SER 84-59	

In conclusion, the root cause program developed at PVNGS consists of the following attributes:

(1) The program will determine the actual operating temperature profiles for the valves.
(2) The program will determine whether external pipe nozzle loads exist and if these loads could affect the valve body.
(3) The program has developed more efficient testing procedures.
(4) The program has developed a valve specific preventive maintenance program.
(5) Offsite testing of the valves will exercise the valve internals and provide more realistic operating and temperature profiles.

While the PVNGS root cause program is comprehensive, the MSSVs and PSVs continue to drift above the current setpoint tolerances. It is understood that other plants utilizing the same model valves have the same setpoint tolerance problems. As such, from previous PVNGS and industry experience, the ±1% setpoint tolerance has shown to be too narrow for realistic compliance. This is clear from the number of occasions in which licensees have requested, and NRC has approved, amendments increasing safety valve setpoint tolerances. The NRC has approved amendments increasing safety valve tolerances in at least the following cases:

South Carolina Elec. & Gas Co. (Virgil C. Summer Nuclear Station, Unit No. 1), 56 Fed. Reg. 4859, 4876 (Feb. 6, 1991) (PSV); Consumers Power Co. (Palisades Plant), 53 Fed. Reg. 48,323, 48,342 (Nov. 30, 1988) (MSSV); Duquesne Light Co. (Beaver Valley Power Station, Unit 2), 53 Fed. Reg. 40,981, 41,003 (Oct 19, 1988) (PSV and MSSV); Portland General Elec. Co. (Trojan Nuclear Plant), 52 Fed. Reg. 35,784, 35,817, (Sept. 23, 1987) (PSV and MSSV). See Also Gulf States Utilities Co. (River Bend Station, Unit 1), 53 Fed. Reg. 20,038, 20,051 (June 1, 1988) (BWR Safety Relief Valve ("SRV")); Commonwealth Edison Co. (La Salle County Station, Units 1 and 2), 50 Fed. Reg. 47,856, 47,878 (Nov. 20, 1985) (SRV).

In addition, the following amendment requests have been filed with the NRC:

Consumers Power Co. (Palisades Plant), 56 Fed. Reg. 11,768, 11,777 (Mar. 20, 1991) (PSV); South Carolina Elec. & Gas Co., South Carolina Pub. Serv. Auth. (Virgil C. Summer Nuclear Station, Unit No. 1), 56 Fed. Reg. 9373, 9386 (Mar. 6, 1991) (MSSV); Pacific Gas and Elec. Co. (Diablo Canyon Power Plant Unit Nos. 1 and 2), 54 Fed. Reg. 40,922, 40,931 (Oct. 4, 1989) (PSV and MSSV).

NRC QUESTION No. 5:

Discuss how reducing the auxiliary feedwater flow factors into the safety analysis.

APS RESPONSE TO No. 5:

Due to the incorporation of instrument uncertainties into the acceptance criteria of the surveillance tests for the essential AFW trains, pump margins (e.g., wear, allowable mini flow, etc.) were reduced. In order to reestablish more conservative margins, APS requested ABB/CE in 1989 to evaluate the impact of a reduced AFW flow of 650 gpm with specific attention to its impact on the UFSAR Chapter 6 and 15 analyses (including natural circulation cooldown per BTP RSB 5-1). Based on this ABB/CE evaluation, a Technical Specification amendment for the AFW change only could have been submitted. During the same time frame, PSV and MSSV Technical Specification changes were also being evaluated by APS. As such, it was decided to submit the AFW and safety valve changes in one submittal. In order to verify that reduction of AFW flow would not adversely impact the safety valves setpoint changes (and vise-versa), evaluations were performed to address the combined effect of the Technical Specification changes. This reevaluation was summarized in Table 2.1-1 of that submittal. A more detailed discussion of the impact of AFW flow rate change was presented in section 2.3 on feedwater system pipe break events (specifically, section 2.3.2 on long term heat removal), section 2.4 on steam generator tube rupture events, section 2.5 on shaft seizure with loss of offsite power events, and section 3 during natural circulation cooldown.

NRC QUESTION No. 6:

Discuss APS position regarding Dresser's disagreement of the instantaneously open PSV model.

APS RESPONSE TO No. 6:

The Dresser position, as described in Reference 1, is "Dresser states that the PSV will pop to about 60-70 percent open at the setpoint, pause for a brief but finite time, and then lift to fully open. They stated that a zero accumulation is not realistic." The APS response to NRC question No. 2 (above), explains that if the brief pause shown by the test data is modeled, it would increase the peak system pressure by approximately 2 psi. Even with the more conservative estimate of a 5.5 psi increase given in Reference 1, the calculated peak pressure would still be less than the NRC acceptance criterion in the Standard Review Plan, 110% of the design pressure.

NRC QUESTION No.7:

Discuss whether the pressurizer would fill upon the safety valves opening later.

APS RESPONSE TO No. 7:

The pressurizer water volume for the LOCV event relating to the requested Technical Specification change is shown in Figure 2 (attached). Since the case under consideration was run for only 20 seconds, no data is presented for times greater than 20 seconds. Figure 3 (attached) presents UFSAR results for CE System 80 plants and PVNGS cycle 1 cases. A comparison reveals that peak pressurizer water volume of less than 780 ft^3 occurred at about 15 seconds in the UFSAR analysis as compared to a peak of 853 ft^3 at about 15 seconds in the present analysis. Thus the pressurizer level is well below the 1800 ft^3 level where the valve will be subject to blowdown water. The initial volume of the pressurizer is selected at 488.8 ft^3 (26% of the wide range) instead of the normal volume of 938.8 ft^3 at 100% power. A lower initial pressurizer volume maximizes RCS peak pressure. Thus the LOCV analysis sets all initial conditions to maximize RCS peak pressure.

In a separate analysis (Reference 9) ABB/CE concluded that for CE plants, the pressurizer liquid level does not reach the elevation of the pressurizer safety valve nozzles during safety valve actuation in a loss of load event with a 20% safety valve blowdown pressure to 2000 psia. This analysis used a different set of initial conditions and a different computer code (LTC) to evaluate the effect on the pressurizer liquid level of extended blowdown of the pressurizer safety valves during the loss of load transient. Referring to Figure 11 of Reference 9, the peak pressurizer pressure of 2525 psia occurs at approximately 8 seconds and drops off to 2000 psia at approximately 16 seconds. In Figure 10 of Reference 9, the adjusted level response starts at 61.5% (pressurizer high level alarm) and levels off at 97.8% by about 16 seconds. Thus the peak pressurizer level reached is aggravated by a higher blowdown pressure and occurs at the time of safety valve closure. In this analysis, all initial conditions were set to maximize liquid level in the pressurizer.

In order to make comparison to a CESEC case, a CESEC run was performed with an initial RCS pressure of 2300 psia, a HPPT setpoint of 2425 psia, a blowdown pressure of 20% (of the PSV setpoint pressure of 2500 psi), and an initial pressurizer level of 61.5% (all initial conditions selected from Reference 9). The CESEC run included the +3% tolerance change for PSVs/MSSVs and resulted in a peak pressurizer level of 78.2% at approximately 12 seconds. Adding an additional 12% pressurizer volume to include conservatisms such as no mixing of initial pressurizer liquid inventory with the insurge volume and no disengagement of flashed steam from the liquid phase, the peak pressurizer volume will be 90.2%, which is well below the 97.8% obtained using the LTC code. The 12% pressurizer volume was approximately the volume added in Reference 9 to determine the peak pressurizer level. The RCS peak pressure for this case was 2696 psia, well below the limiting case presented in the Technical Specification change submittal (Reference 2). Therefore, overfilling of the pressurizer due to the PSV setpoint tolerance is not expected to occur.

LIST OF REFERENCES

1. NRC internal memorandum dated December 4, 1991, from J. E. Rosenthal to R. C. Jones, "Proposed Technical Specification Amendment to Sections 3/4.3.1, 3/4.4.2, 3/4.7.1 and 3/4.7.2 for Palo Verde Nuclear Generating Station, Unit Nos. 1, 2, and 3"

2. Letter 161-03587-WFC/JST, dated November 13, 1990, from W. F. Conway, APS, to Document Control Desk, NRC, Proposed Technical Specification Amendment to Sections 3/4.3.1, 3/4.4.2, 3/4.7.1, and 3/4.7.2"

3. Letter dated March 19, 1987, from J. G. Haynes, APS, to NRC, "Final Report-DER 84-08, Revision 2, A 50.55 (e) and 10 CFR 21 Reportable Condition Relating to ITT/Barton Model 763 Transmitters do not Meet Specifications"

4. Letter 161-03907-WFC/MEP, dated April 29, 1991, from W. F. Conway, APS, to Document Control Desk, NRC, Supplemental Information to Support the Proposed Technical Specification Amendment to Sections 3/4.3.1, 3/4.4.2, 3/4.7.1, and 3/4.7.1.2

5. Report CEN-227, December 1982, "Summary Report on Operability of Pressurizer Safety Valves in C-E Designed Plants"

6. Report CENPD-107 (proprietary), April 1974, "CESEC Digital Simulation of a Combustion Engineering Nuclear Steam Supply System"

7. Letter LD-92-013, dated January 31, 1992, from S. A. Toelle, ABB/CE, to M. E. Powell, APS, "Adequacy of Instantaneous Pressurizer Safety Valve Opening Model in Safety Analysis for Proposed Technical Specification Change"

8. Letter 192-00778-JML/TRB/RKR, dated April 7, 1992, from J. M. Levine, APS, to NRC, "Licensee Event Report 92-004-00"

9. Letter V-CE-17711, dated January 14,1983, from C. Ferguson, Combustion Engineering, to E. E. Van Brunt, Jr., ANPP, "Pressurizer Safety Valve Blowdown Impacts"

FIGURE 3
PRESSURIZER WATER VOLUME vs. TIME FOR LOCV EVENT WITHOUT PROPOSED TECHNICAL SPECIFICATION AMENDMENTS

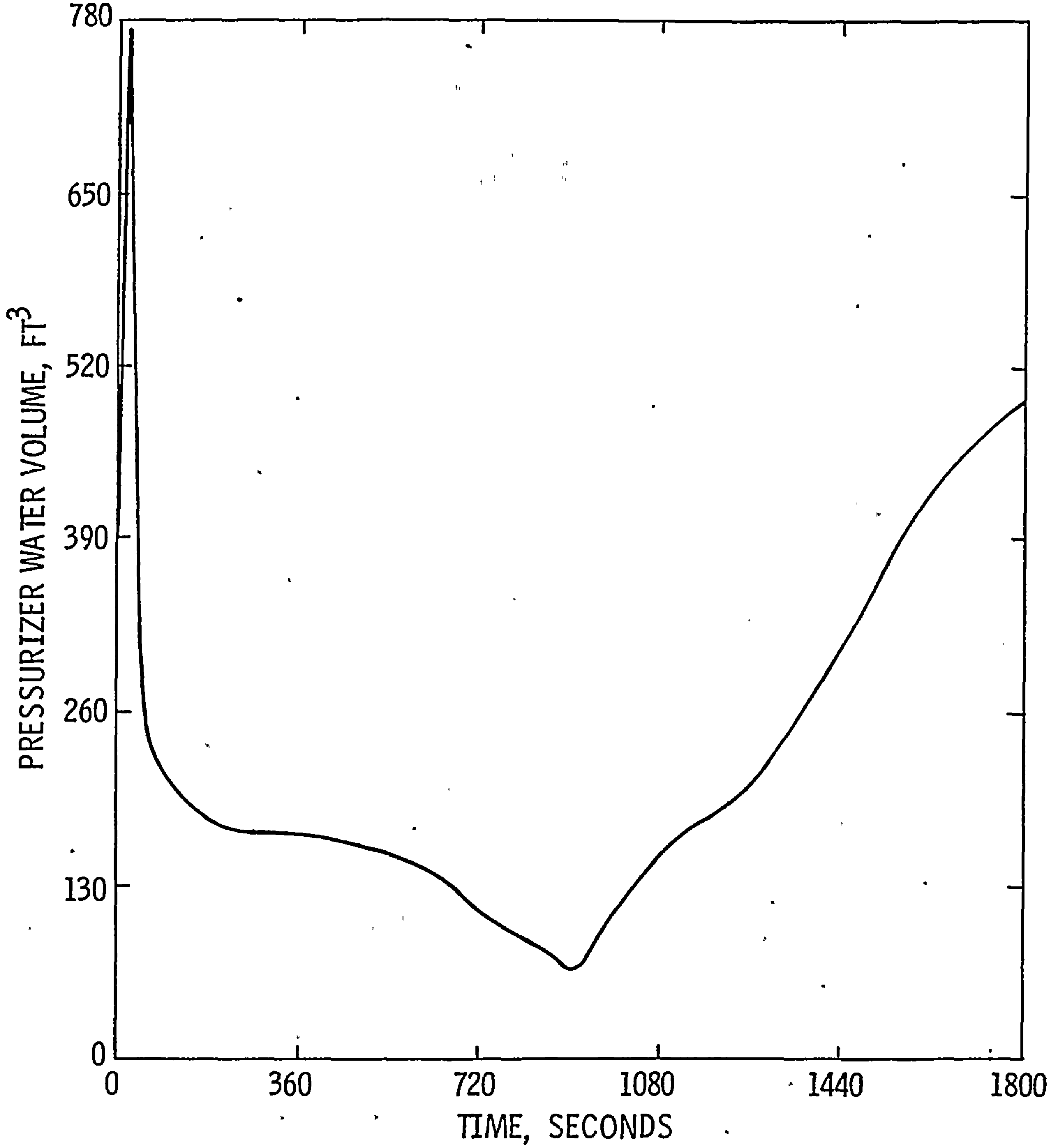

FIGURE 2
PRESSURIZER WATER VOLUME vs. TIME FOR LOCV EVENT
WITH THE PROPOSED TECHNICAL SPECIFICATION AMENDMENTS

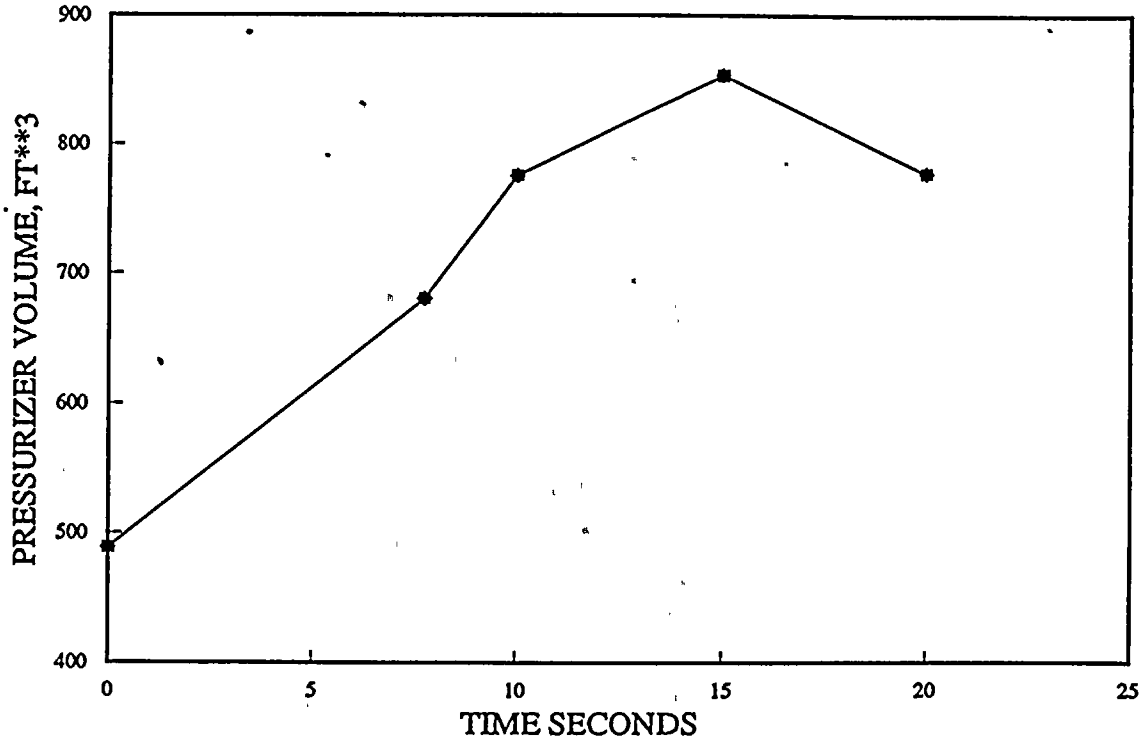

FIGURE 1
RCS PRESSURE vs. TIME FOR LOCV WITH THE PROPOSED TECHNICAL SPECIFICATION AMENDMENTS