10 CFR 50.90

APS

A subsidiary of Pinnacle West Capital Corporation

Palo Verde Nuclear Generating Station

Dwight C. Mims
Senior Vice President
Nuclear Regulatory and Oversight

Tel. 623-393-5403
Fax 623-393-6077

Mail Station 7605
P. O. Box 52034
Phoenix, Arizona 85072-2034

102-06466-DCM/GAM
January 27, 2012

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Sirs:

**Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528, 50-529, and 50-530
Responses to Requests 2 and 3 of the Request for Additional Information Regarding License Amendment Request to Revise Technical Specification 3.7.4, "Atmospheric Dump Valves"**

By letter no. 102-06446, dated December 9, 2011 (Agencywide Documents Access and Management System [ADAMS] Accession No. ML11356A088), Arizona Public Service Company (APS) submitted responses to requests 1a and 1b of the NRC request for additional information (RAI) dated August 31, 2011 (ADAMS Accession No. ML112430084). The RAI pertained to APS's June 22, 2011, request to revise Technical Specification Limiting Condition for Operation 3.7.4, "Atmospheric Dump Valves (ADVs)" (ADAMS Accession No. ML11182A908). The enclosure to this letter contains responses to the remaining requests 2 and 3 of the August 31, 2011, RAI.

No commitments are being made to the NRC by this letter. Should you need further information regarding this response, please contact Russell A. Stroud, Licensing Section Leader, at (623) 393-5111.

A001
NRR

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 1/27/12
(date)

Sincerely,

D.C. Mims

DCM/RAS/GAM/gat

Enclosure: Responses to Requests 2 and 3 of the Request for Additional Information Regarding License Amendment Request to Revise Technical Specification 3.7.4, "Atmospheric Dump Valves"

cc:	E. E. Collins Jr.	NRC Region IV Regional Administrator
	B. K. Singal	NRC NRR Project Manager for PVNGS
	L. K. Gibson	NRC NRR Project Manager
	J. R. Hall	NRC NRR Senior Project Manager
	M. A. Brown	NRC Senior Resident Inspector for PVNGS
	A. V. Godwin	Arizona Radiation Regulatory Agency (ARRA)
	T. Morales	Arizona Radiation Regulatory Agency (ARRA)

Enclosure

Responses to Requests 2 and 3 of the Request for Additional Information Regarding License Amendment Request to Revise Technical Specification 3.7.4, "Atmospheric Dump Valves"

Introduction

By letter dated June 22, 2011, Arizona Public Service Company (APS), the licensee for Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3, submitted a request to the U.S. Nuclear Regulatory Commission (NRC) to revise PVNGS Technical Specification 3.7.4, "Atmospheric Dump Valves (ADVs)" [Reference 1]. The proposed change would require all four ADV lines in a PVNGS unit to be operable in MODE 1 (Power Operation), MODE 2 (Startup), and MODE 3 (Hot Standby), as well as in MODE 4 (Hot Shutdown) when a Steam Generator (SG) is relied upon for heat removal. The proposed change would also modify associated Technical Specification ACTION statements to more closely conform to Standard Technical Specifications for Combustion Engineering plants [References 2 and 3], while maintaining consistency with plant-specific design attributes that are not reflected in the Standard Technical Specifications.

By letter dated August 31, 2011, the NRC staff notified APS that additional information was required in order for the NRC staff to complete its review, and provided APS with a Request for Additional Information (RAI) [Reference 4]. Three requests were included in the RAI. APS provided a response to the first request on December 9, 2011, and informed the NRC staff that additional time was required to confirm several demonstration analyses that were performed in response to the other two requests [Reference 5]. Those analyses have subsequently been independently reviewed and approved in accordance with PVNGS procedures and the quality assurance program requirements of 10 CFR 50, Appendix B, Section III, "Design Control." Thus, this enclosure provides the remaining responses to requests 2 and 3 of the NRC staff's August 31, 2011, RAI.

As noted in the APS letter of June 22, 2011, a postulated single failure of a PVNGS plant component could render as many as two ADVs (i.e., one ADV on each SG) incapable of being operated remotely from the control room. The demonstration analyses described herein, however, assume that four ADVs may be inoperable simultaneously. This is a plant configuration for which Technical Specification 3.7.4, Condition B, would allow continued operation for only a limited (24 hour) period of time.

The safety analyses in the PVNGS UFSAR comply with the guidance contained in Section 15 of NRC Regulatory Guide 1.70, in that the effects of single failures are considered when evaluating the plant response to postulated design basis events [Reference 6]. Because the demonstration analyses performed to support responses to NRC requests 2 and 3 are predicated on a plant configuration that exceeds the single failure criterion of 10 CFR 50, Appendix A, detailed descriptions of these analyses are not planned to be incorporated into the PVNGS Updated Final Safety Analysis Report (UFSAR) [Reference 7]. Demonstration analyses that evaluate design basis events in combination with multiple component failures beyond the single failure criterion are instead controlled internally in accordance with PVNGS design control procedures and, where applicable, may also provide a basis for defining operating limits and/or Emergency Operating Procedure (EOP) mitigation and functional recovery strategies.

NRC Request 2

Regarding the design basis events for which ADVs are required, and which require the consideration of loss of offsite power, please explain how the main steam condenser provides defense in depth to the ADV safety and design functions.

APS Response to NRC Request 2

UFSAR Safety Analyses

For the purpose of performing PVNGS UFSAR safety analyses, the main condenser is treated as a normally operating non-safety related component in accordance with the guidance of NRC Regulatory Guide 1.70. That is, operation of the main condenser may be modeled in an NRC-approved Nuclear Steam Supply System (NSSS) simulation computer code (e.g., CENTS), but only until such time as either a Loss of Offsite Power (LOP) or a Main Steam Isolation Signal (MSIS) is predicted to occur following a postulated design basis event. Condenser operation serves to remove heat that would otherwise have to be accommodated by Main Steam Safety Valves (MSSVs) and/or ADVs; however, heat removal via the condenser is typically disabled in a matter of only a few seconds to a few minutes in UFSAR safety analyses.

For the events that require consideration of a LOP as per the UFSAR and Standard Review Plan, the LOP would occur either at event initiation (i.e., time zero) or three seconds following turbine trip and closure of the turbine admission valves, as described in Chapter 15 of the PVNGS UFSAR. The timing of the LOP for each design basis event is dependent upon the approved analysis methodology for that event. A LOP de-energizes plant components that normally receive electrical power from non-Class 1E busses, including the Circulating Water (CW) system pumps and the condenser air removal vacuum pumps, thereby disabling both condenser cooling and condenser vacuum. Likewise, a LOP would disable the non-safety grade Steam Bypass Control System (SBCS), which is otherwise designed to discharge secondary system steam to either the main condenser (six of eight SBCS valves) or to the atmosphere (two of eight SBCS valves).

The UFSAR safety analyses also consider the potential for MSIS actuation, which may affect the predicted time at which the main condenser is disabled (if a LOP has not already occurred in the event sequence). MSIS may be modeled as either an automatic actuation (e.g., due to high steam generator water level) or as a manual operator action, depending upon the design basis event under consideration. A MSIS results in closure of the Main Steam Isolation Valves (MSIVs), which effectively stops steam flow to the main condenser.

Once the main condenser is disabled in a safety analysis simulation, the condenser is assumed unavailable for the remaining duration of the analysis.

Emergency Operating Procedures (EOPs)

The PVNGS EOPs include a number of mitigation and functional recovery strategies that are not specifically modeled in the UFSAR safety analyses. In some cases, these strategies credit non-safety grade equipment, such as the main condenser, that may remain available following a design basis event (e.g., if a LOP does not occur), or that may be restored to service as part of the site emergency response (e.g., upon restoration of offsite power following a LOP).

EOP mitigation and functional recovery strategies that credit the main condenser for heat removal and secondary system inventory control involve two primary pathways. The two primary pathways are: (a) secondary system steam flow through the SBCS valves to the main condenser, and (b) liquid flow from the secondary side of the steam generators through blowdown lines to the main condenser. The latter of these is specifically identified in the EOPs as a strategy that may be used to prevent steam generator overfill following a Steam Generator Tube Rupture (SGTR).

If all four ADVs are incapable of being operated remotely from the control room, and if the main condenser is rendered and remains unavailable following a postulated design basis event, the EOPs specify local manual handwheel operation of the safety related ADVs to dump steam to atmosphere. An alternative action could use two non-safety related SBCS valves to divert steam to the atmosphere instead of the condenser. Heat removal would also be available through steam discharge to the atmosphere via automatic cycling of the MSSVs.

The demonstration analyses described in the APS response to NRC request 3 (below) demonstrate that the MSSVs may be used to maintain a PVNGS unit in a safe hot standby condition for at least four hours following a postulated design basis event, thus providing time for implementation of EOP or another alternative strategy.

NRC Request 3

Discuss the impact that local manual ADV operation or maintaining steam generator pressure with main steam safety valves would have on safety margin for design basis events, including but not necessarily limited to:

a. Postulated loss-of-coolant accidents.

b. Natural circulation cooldown as described in Generic Letter 81-21.

c. Steam generator tube rupture events.

d. Main steam and feedwater line breaks.

APS Response to NRC Request 3

Background

The original design basis of the PVNGS units, which originated with the Combustion Engineering "System 80" standard plant design, required that the units be capable of maintaining a safe hot standby condition for a period of up to four hours following certain design basis events, after which plant operators would commence a controlled cooldown to cold shutdown conditions. (See for example, Section 7.4 of the Combustion Engineering Standard Safety Analysis Report [CESSAR] [Reference 8], and its associated NRC Safety Evaluation Report, NUREG-0852 [Reference 9].)

APS and Westinghouse Electric Company, evaluated whether the design of the PVNGS units remained sufficiently robust, after previous power uprates and other design modifications, to control or accommodate a variety of design basis events (including a LOP) while maintaining a safe hot standby condition for four hours. During the four-hour time frame, no ADV operation (either remote or local) was assumed, and steam generator pressure was, instead, maintained above the normal secondary system operating pressure, by cycling of MSSVs. The design basis events that were evaluated, and the results of those evaluations, are presented in the subsections below.

Furthermore, it was assumed that following the four-hour hot standby period, plant operators would not necessarily be restricted to any single method for commencing a controlled cooldown. Instead, the operators could use any available EOP mitigation or functional recovery strategy, depending upon the availability of plant equipment, the status of equipment restoration post-LOP, and plant conditions. It is noted that four hours provides sufficient time to staff emergency response facilities, to measure and assess plant and environmental conditions, and to plan and begin execution of various equipment repairs. Local manual operation of ADVs would be but one of the options to consider.

APS elected to present the results of the natural circulation cooldown evaluation first as it provides a basis for the other event evaluations.

Natural Circulation Cooldown

At the request of APS, Westinghouse evaluated how natural circulation cooldown would be affected if four ADVs were rendered incapable of remote operation. The NRC RAI specifically mentions NRC Generic Letter 81-21, which identified a potential concern with void formation in the Reactor Vessel Upper Head (RVUH) during a natural circulation cooldown [Reference 10]. The NRC staff, however, in accordance with NRC Branch Technical Position RSB 5-1, has previously accepted the PVNGS licensing basis that RVUH voiding and venting is acceptable during a natural circulation cooldown [Reference 11]. Natural circulation cooldown is addressed in an analysis of record (AOR) that is summarized in PVNGS UFSAR Appendix 5C.

In the AOR analysis cases, the first time the ADVs are operated is early in the event, at 500 seconds. The operator opens the ADVs and maintains pressure just below the lowest MSSV opening pressure setpoint. This is done simply to minimize MSSV cycling, as there is no attempt to significantly lower the RCS or SG temperature in the early phase of the event. Therefore, deferring early opening of the ADVs and allowing the MSSVs to cycle as necessary to maintain SG pressure, would have no appreciable impact on the event results.

The next operation in the AOR involving the ADVs is to throttle them open (one per SG), to commence a cooldown of the RCS at four hours into the event sequence. If all four ADVs are unavailable for remote operation from the control room, then local manual operation using handwheels would suffice, and the natural circulation cooldown would proceed as it is currently described in the AOR.

The Westinghouse evaluation also evaluated how long the initiation of a controlled cooldown could be delayed after holding the plant in hot standby. Based on margins available in the AOR from excess condensate storage inventory, and assuming the use of a faster cooldown rate, the Westinghouse evaluation demonstrated that initiation of the cooldown could be delayed for up to 11.8 hours, well beyond the four-hour period assumed in the AOR.

Postulated Loss-of-Coolant Accidents (LOCAs)

APS and Westinghouse Electric Company evaluated how postulated LOCAs would be affected if all four ADVs were rendered unavailable for the initial four hours of the event. For this evaluation, LOCAs were divided into two size groups: large break and small break.

Large break LOCAs include those breaks that are sufficiently large such that the break flow and energy release are sufficient to remove all core decay heat and sensible heat. Large break LOCAs do not require heat removal by the SGs in order to cool the Reactor Coolant System (RCS) because the energy removed from the RCS is directed to the containment via the break. Therefore, neither ADV nor MSSV operation is required for mitigating large breaks.

Small break LOCAs (SBLOCAs) include those breaks that are small enough to require some energy be relieved through the SG secondary, either through the safety related MSSVs or ADVs (or, as an alternative, through the non-safety related SBCS to the atmosphere or condenser, if available). SBLOCAs are addressed in an AOR that is summarized in PVNGS UFSAR Section 6.3.

The SBLOCA AOR establishes the methodology by which RCS cooling is maintained during a SBLOCA event, which limits fuel clad temperature, clad oxidation, and consequential fuel damage, as required by 10 CFR 50.46. This licensing basis methodology does not credit operation of the ADVs. The break sizes analyzed in the AOR, ranging from 0.01 ft^2 to 0.07 ft^2, all relieve some amount of RCS energy via the break, with the excess heat being removed via the secondary system MSSVs. The plant response for this group of breaks was shown to allow successful recovery of RCS inventory with Safety Injection (SI) pumps, without exceeding peak core temperature limits. The cases were not terminated until after core temperatures had peaked and the RCS inventory was recovering due to SI flow. The Westinghouse evaluation demonstrated that the initial four-hour unavailability of the ADVs would not impact the results reported in the SBLOCA AOR.

With regard to long-term cooling and commencement of a controlled plant cooldown following a SBLOCA, it was determined that operation of either the ADVs or the non-safety grade SBCS would be acceptable. To determine how long the plant could remain in a safe hot standby condition before initiating a RCS cooldown, the natural circulation cooldown analysis was selected as a limiting measure for the SBLOCA event because it bounds the maximum demand for condensate storage inventory. That is, the RCS cooldown could be initiated somewhat later for a SBLOCA than for the natural circulation cooldown analysis, because the SBLOCA itself discharges energy from the RCS to the containment and thus reduces the amount of heat that must be removed via the secondary system. The larger the break, the less energy is required to be released via the secondary system, and the longer condensate storage inventory would be available. Accordingly, the Westinghouse SBLOCA evaluation demonstrated acceptable results from a plant cooldown commenced up to 11.8 hours following the event, exceeding the four-hour hot standby period of the Natural Circulation Cooldown Analysis.

In conclusion, the results of the Westinghouse evaluation demonstrated for large and small beak LOCAs the following:

- There is no adverse effect or degradation of margin to the 10 CFR 50.46 acceptance criteria if all four ADVs are incapable of remote operation from the control room.

- RCS cooldown to cold shutdown conditions could be commenced after four hours in hot standby, using available components and systems (e.g., local manual operation of the ADVs), and sensible and decay heat could be accommodated without exhausting condensate inventory.

Steam Generator Tube Rupture (SGTR)

APS evaluated how a SGTR event would be affected if all four ADVs were incapable of remote operation from the control room. For the purposes of this evaluation, APS performed a demonstration analysis with the NRC-approved CENTS computer code [Reference 12], and modeled the event in a manner similar to that used for the limiting licensing basis AOR described in PVNGS UFSAR Section 15.6.3.

That is, the selection methodology for initial conditions for analysis were generally consistent with those used in the licensing basis AOR. However, the demonstration analysis used an initial steam generator water level that was representative of full power operating conditions (which maximizes the potential for overfill), rather than a very low initial water level like that used in the AOR (which maximizes the duration of tube uncovery during the event).

The demonstration analysis model also differed from that used in the AOR, in that a newer code version and associated basedecks allowed for more detailed modeling (i.e., additional nodes) in the SG tubes as well as the reactor vessel downcomer. NRC staff approval of these CENTS code upgrades is documented in a Safety Evaluation dated December 1, 2003 [incorporated into Reference 12]. Also, whereas the licensing basis AOR utilized the Homogeneous Equilibrium Model (HEM) to calculate choked flow through the ruptured SG tube, the demonstration analysis utilized the Henry-Fauske correlation, which has been used in previous PVNGS SGTR licensing basis analyses.

The licensing basis AOR assumed a variety of control room operator actions, including manual reactor trip, opening of ADVs a few minutes after reactor trip (with one ADV on the ruptured SG immediately failing to the full open position), and direct manual control of auxiliary feedwater, high pressure safety injection, pressurizer vents, pressurizer heaters, and manual actuation of MSIS. For the demonstration analysis, however, it was assumed that no operator actions would occur during the four-hour hot standby period, and that equipment that automatically actuated (e.g., MSSVs) would operate within setpoints and limits established by Technical Specifications and design basis documents (e.g., pump curves, instrument loop uncertainty calculations). Thus, the demonstration analysis was intended to show that the PVNGS plant design was robust enough to control and accommodate a SGTR event, without overfilling of the ruptured SG and without excessive dose consequences, even if all four ADVs were unavailable during the hot standby period.

Both hot side and cold side breaks were evaluated in the demonstration analysis. Reactor trip automatically occurred approximately 10 minutes into the event sequence, due to rapid depressurization of the RCS and a resultant Core Protection Calculator System (CPCS) hot leg saturation margin trip. This was quickly followed by a turbine trip, a LOP following turbine trip, and a Safety Injection Actuation Signal (SIAS) due to low pressurizer pressure. In the RCS, the LOP resulted in a loss of forced flow from the Reactor Coolant Pumps (RCPs) and entry into natural circulation conditions, while the High Pressure Safety Injection (HPSI) pumps delivered enough flow to the RCS to make up for the primary-to-secondary flow rate through the ruptured SG tube (in excess of 500 gallons per minute at event initiation).

In the secondary system, automatic cycling of MSSVs and automatic delivery of auxiliary feedwater to the intact SG provided heat removal per the plant design; however, the water level in the ruptured SG generally trended upward, with occasional fluctuations in level as MSSVs opened and closed, and as auxiliary feedwater was delivered to the intact SG. An automatic MSIS did not occur for more than three hours in the event sequence so the two SGs remained thermally coupled through the main steam header downstream of the MSIVs. Delivery of auxiliary feedwater to the intact

SG thereby decreased pressure in both SGs as well as the header and associated piping.

It is assumed that, at the end of the four-hour period in hot standby, plant operators will take control of the plant and initiate a controlled cooldown to cold shutdown conditions.

This demonstration analysis resulted in the following conclusions:

- The PVNGS Replacement Steam Generators (RSGs), which are larger than the Original Steam Generators (OSGs), provided margin to accommodate a SGTR event without overfill, even after implementation of power uprate conditions. Spillage of water through the SG outlet nozzles and into the main steam lines did not occur during the four-hour hot standby period.

- Primary and secondary system peak pressures remained within 110% of design pressure.

- Fuel failure would not occur. (The existing licensing basis AOR is more limiting with respect to the potential for fuel failure, because of the depressurization associated with the secondary system excess steam demand caused by the failed open ADV to maximize potential dose consequences. Fuel failure is not predicted for the AOR, either.)

- Offsite radiological doses for the event were calculated using CENTS code output, Technical Specification primary and secondary system iodine specific activities, and pre-accident (PIS) and accident-generated (GIS) iodine spikes. The licensing basis steam generator tube rupture with loss of offsite power and single failure (SGTRLOPSF) analysis used a conservative flashing fraction of 1.0 when steam generator U-tubes were partially uncovered during the transient. However, the demonstration analysis utilized an isenthalpic flashing fraction model, with no credit taken for iodine scrubbing. This change is justified because, for the demonstration analysis, there was no superimposed excess steam demand and therefore no occurrence of steam generator dryout.

  Two-hour thyroid doses at the Exclusion Area Boundary (EAB) were less than 15 rem for the PIS case and less than 6 rem for the GIS case, which meet the acceptance criteria of Standard Review Plan (SRP) Section 15.6.3 [Reference 13]. (Whole body doses are less limiting than thyroid doses for PVNGS SGTR events.) Because the eight-hour doses at the Low Population Zone (LPZ) are highly dependent upon presumed mitigation strategies following the four-hour period in hot standby, they were not explicitly calculated; however, calculated four-hour doses at the LPZ also remained within SRP Section 15.6.3 acceptance criteria (i.e., less than 7 rem for the PIS case and less than 5 rem for the GIS case). These four-hour dose estimates support a conclusion that several mitigation strategies (e.g., draining the ruptured SG to the main condenser, local manual ADV operation, etc.) provide feasible options following the temporary hold in hot standby. The licensing basis SGTRLOPSF analysis, which assumes a failed open ADV to maximize potential dose consequences, remains bounding for eight-hour doses because the analysis models the cooldown of an affected unit and the removal of decay heat, sensible heat, and Reactor Coolant Pump (RCP) heat through secondary steam releases to the environment.

Main Steam Line Break (MSLB)

APS performed a demonstration analysis for the post-trip MSLB long-term response, assuming all ADVs were unavailable. This demonstration analysis was based on the licensing basis AOR, described in PVNGS UFSAR Section 15.1.5.

The UFSAR Chapter 15 MSLB event does not credit ADV operation for the first 30 minutes after initiation of the event. For that period of time, associated UFSAR figures demonstrate the most limiting case for reactivity and Departure from Nucleate Boiling Ratio (DNBR) is the Main Steam Line Break at Full Power with Loss of Offsite Power (MSLBFPLOP). The figures show that both reactor subcriticality and DNBR response improve after limiting values are achieved early in the event sequence. Therefore, the demonstration analysis focused on long-term RCS pressure, secondary system pressure, and Pressurizer Safety Valve (PSV) and MSSV response.

Because of the assumed unavailability of four ADVs, the long-term transient relies on the automatic actuation of the PSVs, MSSVs, and auxiliary feedwater system to maintain primary and secondary pressure, as well as intact steam generator level. Primary system inventory control is provided by HPSI. Without the ADVs for heat removal, the long-term event response will be a heat-up event. To evaluate this configuration the methodology for the AOR was utilized and a CENTS case was executed for four hours to demonstrate the plant reaches a stable condition without ADV operation. No significant design inputs associated with the current UFSAR analysis were changed for this evaluation; however, a few CENTS inputs were modified to correct Software Error Notices (SENs), and no operator action was assumed for four hours rather than 30 minutes.

The demonstration analysis revealed that early in the event, the RCS temperature and pressure increase is due to SG dryout and a resultant loss of heat removal capability. As the event progresses, the PSVs and MSSVs cycle, eventually causing the water level in the intact SG to decrease to the Auxiliary Feedwater Actuation Signal (AFAS) setpoint. Auxiliary feedwater is delivered to the intact SG until level increases to the AFAS reset setpoint. This phenomenon repeats periodically during the 4-hour period in hot standby. At the end of the 4 hours, it is assumed that plant operators will commence a controlled cooldown.

The results of the demonstration analysis confirm that there is no degradation of margin to the acceptance criteria, even if four ADVs are unavailable.

This case resulted in the following:

- The maximum RCS and secondary system pressures remain less than 110% of design pressure.
- The maximum pressurizer water volume remains under control and the PSVs do not pass water.

Feedwater Line Break (FWLB)

APS performed a demonstration analysis for the Feedwater Line Break with a Loss of Offsite Power and a Single Failure (FWLBLOPSF) event. The AOR for this event is described in PVNGS UFSAR Section 15.2.8. This is the limiting heat removal event which currently credits operator action to open an ADV 10 percent on the intact SG from the control room at 20 minutes after event initiation. The demonstration analysis evaluated a configuration that assumed no ADVs on any SG were able to be opened for four hours and used the current FWLBLOPSF AOR methodology and a CENTS code simulation to demonstrate the plant reaches a stable condition with heat removal provided only by the MSSVs. No significant design inputs associated with the current UFSAR analysis were changed for this evaluation; however, a few CENTS inputs were modified to correct SENs.

The demonstration analysis, like the AOR, assumed that one charging pump would continue to provide flow to the RCS after the LOP. However, consistent with guidance provided in EOPs, the analysis also assumed that operators would take action to secure the running charging pump at 20 minutes after event initiation (i.e., instead of opening an ADV 10% as modeled in the AOR). At the end of the four hours, it is also assumed that plant operators will commence a controlled cooldown.

The results of this evaluation demonstrate that there is no degradation of margin to the acceptance criteria if no ADVs are available, provided operators secure the operating charging pump within 20 minutes after event initiation to prevent pressurizer overfill. That action is in station procedures, and operators have been trained on that action.

This evaluation case resulted in the following:

- The peak RCS and secondary system pressures remain below 110% of design pressure.
- The pressurizer does not go water solid.
- At the maximum pressurizer water volume, no water entrainment is postulated to occur.

- The MSSVs cycled repeatedly to maintain SG pressure and RCS temperature, during the four-hour hot standby period. The number of times the MSSVs cycled was well within the number of cycles for which the MSSVs have been successfully tested [Reference 14].

Conclusion

There would be sufficient time for the operators to diagnose and mitigate an event even if the ADVs were not available. The MSSVs would provide adequate heat removal for several hours without the use of ADVs. Therefore the current TS completion time of 24 hours for four inoperable ADVs remains adequate.

The requested Technical Specification change would allow for continued operation of a PVNGS unit for up to 24 hours when all four ADV lines are inoperable. The proposed completion time for this condition remains the same as in the current PVNGS Technical Specifications. The demonstration analyses described herein confirms that, should a postulated accident or transient occur while a PVNGS unit is in this condition, the unit may be maintained in a safe hot standby condition for at least four hours, without reliance on the ADVs. Thus there is time for operators to diagnose the event, assess plant conditions, and obtain support from emergency response personnel as necessary to effect one or more mitigation strategies with the aim of placing the unit in a safe cold shutdown condition. Such strategies include local manual operation of the ADVs, as specified in station Emergency Operating Procedures (EOPs), and other alternative actions that emergency response personnel may determine are appropriate for the event under consideration.

References

1. APS Letter to NRC No. 102-06370-DCM/DFS, "Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3; Docket Nos. STN 50-528, 50-529, and 50-530, Request for Amendment to Technical Specification 3.7.4, 'Atmospheric Dump Valves (ADVs)'," dated June 22, 2011. [NRC ADAMS Accession No. ML11182A908]
2. NUREG-1432, "Standard Technical Specifications – Combustion Engineering Plants, Specifications," Volume 1, Revision 3, June 2004. [NRC ADAMS Accession No. ML041830597]
3. NUREG-1432, "Standard Technical Specifications – Combustion Engineering Plants, Bases," Volume 2, Revision 3, June 2004. [NRC ADAMS Accession Nos. ML041830100 (Part 1 of 2) and ML041830101 (Part 2 of 2)]
4. NRC Letter to APS, "Palo Verde Nuclear Generating Station, Units 1, 2, and 3 – Request for Additional Information Regarding License Amendment Request to Revise Technical Specification 3.7.4, 'Atmospheric Dump Valves'(TAC Nos. ME6566, ME6567, and ME6568)," dated August 31, 2011. [NRC ADAMS Accession No. ML112430084]

5. APS Letter to NRC No. 102-06446-DCM/DFS, "Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3, Docket Nos. STN 50-528, 50-529, and 50-530, Response to Request for Additional Information Regarding License Amendment Request to Revise Technical Specification 3.7.4, 'Atmospheric Dump Valves (ADVs),' (TAC Nos. ME6566, ME6567, and ME6568)," dated December 9, 2011. [NRC ADAMS Accession No. ML11356A088]

6. NRC Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, LWR Edition," Revision 3, November 1978. [NRC ADAMS Accession No. ML011340122, which is a "zip" package that includes ML011340072 (Part 1 of 3), ML011340108 (Part 2 of 3), and ML011340116 (Part 3 of 3)]

7. APS Letter to NRC No. 102-06375-DCM/TLC, "Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3, Docket Nos. STN 50-528/529/530, Updated Final Safety Analysis Report, Revision 16," dated June 30, 2011.

8. Docket No. STN 50-470, "Combustion Engineering Standard Safety Analysis Report (CESSAR)," through Amendment No. 9, February 1984.

9. NUREG-0852, "Safety Evaluation Report Related to the Final Design of the Standard Nuclear Steam Supply Reference System, CESSAR System 80, Docket No. STN 50-470," dated November 1981, and NUREG-0852 Supplement Nos. 1 (March 1983), 2 (September 1983), and 3 (December 1987).

10. NRC Generic Letter 81-21, "Natural Circulation Cooldown," dated May 5, 1981.

11. NRC Letter to APS, "Evaluation of the Natural Circulation Cooldown Capability for Palo Verde (TAC Nos. 56647 and 56648)," dated April 18, 1988.

12. CENPD-282-P-A, "Technical Description Manual for the CENTS Code," Volumes 1 through 4, Revision 2, March 2005 (also designated as WCAP-15996-P-A, Revision 1).

13. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," Section 15.6.3, "Radiological Consequences of Steam Generator Tube Failure," Revision 2, July 1981.

14. APS Letter to NRC No. 102-04847-CDM/TNW/RAB, "Palo Verde Nuclear Generating Station (PVNGS) Unit 2, Docket No. STN 50-529, Response to Request for Additional Information Regarding Steam Generator Replacement and Power Uprate License Amendment Request," dated October 11, 2002. [NRC ADAMS Accession No. ML022940385]