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ZIMMERMAN,R. Region 5, Ofc of the Director

SUBJECT: Advises that Unit 2 will be shutdown to inspect steam generators for feedwater sparger damage.

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June 13, 1990

Mr. Roy Zimmerman, Director
Division of Reactor Safety and Projects
U. S. Nuclear Regulatory Commission
1450 Maria Lane, Suite 210
Walnut Creek, CA 94596-5368

Dear Mr. Zimmerman:

Subject: Docket Nos. 50-361 and 50-362
Feedwater Sparger Damage
San Onofre Nuclear Generating Station Units 2 and 3

As indicated in the June 1, 1990 letter from Mr. Harold B. Ray, San Onofre Unit 2 will be shut down to inspect the steam generators for feedwater sparger damage and its effects, and to perform required modifications and repairs as indicated by ongoing work on Unit 3, no later than following return to service of Unit 3. Therefore, Unit 2 will continue to operate until about July 7 but no later than July 15, 1990 (a period of about 5 to 6 weeks).

To ensure all safety implications associated with continued operation of Unit 2 were considered, this limited operation was reviewed and approved by the Onsite Safety Review Committee (OSRC). In support of the OSRC review, a white paper was prepared to summarize the evaluation of the various safety issues in a manner that could be discussed by the OSRC members. A copy of the final white paper, which served the purpose of a "safety evaluation," is provided as an enclosure to this letter.

The enclosed evaluation addresses several aspects of plant safety which could potentially be affected by damage to the feedwater sparger. These include waterhammer, mechanical support of the sparger, effect of debris on blowdown isolation, thermal stresses on the steam generator shell, degradation of steam generator tubes, and auxiliary feedwater delivery. The conclusion of this evaluation is that if the Unit 2 sparger is damaged, it will not affect the ability of the plant to operate safely or for equipment important to safety to operate.

Although the evaluation concludes that serious damage to the steam generator tubes is unlikely, several administrative actions have been taken. First, the Condenser Air Ejector Radiation Monitor has been set to alarm if

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tube leakage exceeds 30 gallons per day with no more than a 15 minute processing delay. If this alarm occurs, Chemistry will take confirmatory samples and begin trending air ejector activity. Second, Chemistry has been directed to notify Operations and Station Technical if they see an RCS sample with activity greater than 0.05 micro Ci/cc Dose Equivalent Iodine. Third, setpoints have been changed to decrease the plant operating margin to ensure that negligible fuel failure would occur in the unlikely event of a limiting transient.

If you have any questions regarding our evaluation, please let us know.

Very truly yours,

Enclosure

cc: J. B. Martin, Regional Administrator, NRC Region V
C. Caldwell, NRC Senior Resident Inspector, San Onofre Units 1, 2 and 3
L. E. Kokajko, NRC Project Manager, San Onofre Units 2 and 3

Safety Evaluation Concerning Limited
Continued Operation of San Onofre Unit 2

Purpose:

The purpose of this Safety Evaluation is to address the implications for limited continued operation of San Onofre Unit 2 of feedwater sparger damage identified during inspection of Unit 3 steam generators. Continued operation of Unit 2 until Unit 3 is returned to service about July 7, 1990 (a period of about 5 weeks) is considered.

Discussion:

Damage to the feedwater sparger could potentially impact several aspects of plant safety. These include potential for waterhammer, mechanical support of the sparger, the effect of debris on blowdown isolation, thermal stresses on the steam generator shell due to uneven feedwater flow distribution and degradation of the steam generator tubes due to damage caused by debris generated by the failure of the sparger. The damage is such that it provides more flow area so no concern about the ability of delivering Auxiliary Feedwater exists.

The plant was designed to maintain the sparger filled with water by the use of J tubes and a tight fitting sparger sleeve. The damage seen in Unit 3 resulted in a large flow area on the bottom of the sparger piping. Thus, during a loss of feedwater the ring would empty. Initiation of Auxiliary Feedwater could lead to a refilling of the sparger with cold water depending upon the area of damage hypothesized for Unit 2 and the time without feedwater. This condition was simulated during startup testing on Unit 2. In that case, the sparger collapsed due to the creation of a vacuum upon sudden condensation of the steam in the sparger. All feedwater piping outside of the generator was unaffected by this transient. To avoid such damage to the sparger in the future, the spargers in both units were replaced with schedule 120 piping which was shown to be able to withstand the generation of a complete vacuum inside the sparger with the generator at normal operating pressure. In addition, the vent area of the J tubes was doubled to minimize the pressure differential that could be created. While the creation of holes on the underside of the sparger tends to empty the pipe it also tends to prevent Auxiliary Feedwater from filling the pipe later and if it does, the piping has been shown by analysis and experience to be able to withstand the transient that would result.

Each sparger arm is supported in three places. It is welded to the inlet box and is supported by saddle blocks in the middle and at the end of the pipe. The degradation seen in the sparger weld area does degrade that point of support but the other two supports remain unaffected. Analysis has shown that the remaining support of the sparger was adequate both for normal operation and to withstand the effects of a seismic event.

It is possible that the sparger damage could generate small pieces of debris that could make their way into the blowdown pipe. That pipe has 1/2" diameter flow holes in it. Debris smaller than this dimension could be carried by blowdown to the blowdown isolation valve. This valve is a cage type valve in which the valve plug travels on the inside of a cage with holes of about 0.6" diameter. Debris capable of getting into the blowdown line should not hang up in the valve cage. Once inside the cage the debris should fall to a large volume below the valve seat. An inspection of the Unit 3 blowdown isolation valve showed small flakes of material in this volume. The material was about 1/4" in size and appears to have come from the feedwater heater train. The only

significant consequence of a failure of this valve to operate would be in a tube rupture event. That event does not postulate actions to isolate the affected generator until 30 minutes after the event which leaves adequate time for manual isolation of blowdown.

Combustion Engineering has evaluated the potential for the sparger damage to result in unacceptable stresses on the steam generator shell as a result of uneven feedwater distribution and has concluded that this is not a problem. The generators have a large recirculation flow rate so that any uneven inlet flow is quickly mixed. The temperatures seen from such a situation are similar to those considered in the generator design with the varying feedwater temperature as the power level is changed.

The most significant consideration is the potential for steam generator tube damage due to debris. If Unit 2 does have debris in the generators it will be of the same type as that seen in Unit 3. The debris consists of pieces of carbon steel piping that are irregular in shape, curved, and of variable thickness due to erosion. Such debris might damage a peripheral tube because of impact but this is extremely unlikely. Tubes are normally under tensile stress due to the higher pressure in the RCS so that any impact damage due to a loose part on the secondary side would be resisted by this differential pressure. Should the loose part damage a pressurized tube it would most probably generate a puncture which would result in a tube leak rather than a serious rupture of the tube.

About 1% of the peripheral tubes in Unit 2 have been plugged but not staked. The plugging was due to reasons other than debris wear. If the debris were to impact a plugged tube the potential for shearing the tube is greater. This tube could then become a loose part which could wear against inservice tubes and cause them to fail. This is the scenario seen at Ginna which resulted in a tube rupture in 1982. The loose part had been in the generator for many years and had caused damage to several peripheral tubes that caused them to fail eddy current testing and as a result they were plugged at various refueling outages. Eventually, the debris completely failed one plugged tube and that tube wore against an inservice tube for about 60 days. The wear mark was broad and when the tube finally failed it did so with no warning and created a leak of 720 gpm. If debris exists in Unit 2, it has only been in the generator for 5 months. A large survey of peripheral tubes near the debris found in Unit 3 showed no wear or tube damage.

The other potential tube wear scenario is for a thin piece of debris to work its way into the tube bundle and become lodged between two or more tubes. It can then fret these tubes. One such piece of debris was found in Unit 3. It created a total of four wear marks on three tubes. The deepest wear penetrated 32% of the tube wall. The total length of each wear mark was about 0.4 inches. Given the irregular nature of this debris one can assume that there would be a range of wear marks that would result. Generally, one would expect sharp wear marks due to limited surface contact afforded by broken pieces of steel. One would certainly not expect all the wear to occur at the same rate. Should a piece of debris end up causing a tube to fail it would be expected to create a leak that would grow slowly with time rather than a sudden rupture. All three units at San Onofre have had experience with tube leaks caused by tube vibration against smooth steel support surfaces. In every case, the leaks have started out very small and have grown gradually over many days.

To have a sudden tube rupture it is necessary to produce a large smooth wear pattern over a large area. Sharp cuts or punctures do not lead to rupture due to the very high burst pressure for undamaged tubes. NUREGs 0718 and 2336 reported results of tube rupture testing in some detail. The differential pressure necessary to burst an undamaged tube is about 10,000 psid for San Onofre Unit 2. Using the correlation in NUREG 2336 for elliptical wastage, a tube would have to be worn to 4.1% of its original thickness before it would rupture with the differential pressure of 1350 psid normally seen on tubes at full power. Such tubes show a greater resistance to collapse than they do to rupture. A tube that has been worn to 4.1% of its original thickness would require a reverse pressure differential of 2800 psid before it would collapse. This is far in excess of the maximum reverse pressure differential that could be created in any credible accident. The worst possible reverse pressure differential would occur in a LOCA where the RCS depressurizes and the steam generators stay at 1000 psia. Clearly, any tube that would rupture during an RCS depressurization event would have already failed in normal operation. Therefore, in evaluating the possibility of a concurrent tube rupture with other accidents, any accident that causes a reduction in RCS pressure relative to the steam generators has no potential for causing a tube rupture. This eliminates events that are dominated by either a loss of RCS inventory or an RCS cooldown.

All analyzed accidents assume that RCS activity starts at a level of at least 1.0 μCi/cc Dose Equivalent Iodine as a result of 1% failed fuel. They also assume the steam generators have a 1.0 gpm leak and start at 0.1 μCi/cc. In reality, Unit 2 has no failed fuel pins and no steam generator tube leakage. The RCS typically has an activity of about 0.025 μCi/cc with no propensity to show iodine spiking. The steam generators have an activity which is less than the limit of detection at 1E-8 μCi/cc. In any accident that does not result in fuel failure, the total amount of activity available to be released to the environment is no more than about 5.7 Ci. This assumes that all the activity in the RCS and all the activity in both steam generators is released to the environment. In the Main Steamline Break outside of containment analysis, the activity assumed to be released to the environment is at least 13.8 Ci based on the activity assumed in one generator and the amount of RCS leakage during the event. Thus the dose consequence of any event that does not fail fuel but does have a concurrent tube rupture (or multiple ruptures) is bounded by the dose consequences of the currently analyzed Main Steamline Break accident. Another way of looking at it is that the activity in the RCS is only 25% of that assumed for the secondary system. Therefore, the rupturing of a tube which caused RCS water to mix with the steam generator water can not result in activity levels in excess of those already assumed.

The highest pressure differential that could be created would occur in a Main Steamline Break accident. As a worst case, RCS pressure could remain at 2250 and the steam generator could become completely depressurized. At this pressure differential, a tube needs to have a minimum wall thickness of no more than 9.2%. In reality, the pressure differential would be considerably less because the cooldown associated with a Main Steamline Break causes the RCS to depressurize as well. The actual maximum differential would be 1800 psid corresponding to a tube thickness of 6.5%. For a tube to concurrently rupture during an MSLB event, it would have to have a minimum wall thickness between 6.5% and 4.1% and would have to have a large smooth elliptical wear pattern. This is extremely unlikely. Assuming a tube wear rate of 0.6% per day (which is necessary to cause the hypothetical wear in a 6 month period), the time period in which the tube thickness is between 6.5% and 4.1% is 4 days. The probability of an MSLB occurring during a 4 day period when the most badly worn tube would be in a condition in which it could potentially rupture is small enough for the

concurrent tube rupture with a MSLB to not be credible. The point of minimum DNBR occurs almost immediately since the reactor trip very quickly drives the core subcritical. The subsequent cooldown does add positive reactivity but at the current time in core life, this is a much smaller effect than assumed in the FSAR analysis. The current moderator temperature coefficient on Unit 2 is about -1.23 E-4 dk/k/F whereas the accident analysis assumed -3.3 E-4 dk/k/F.

There are only two limiting faults which can cause fuel failure and also RCS pressurization. These are control element assembly ejection and RCP sheared shaft. As a result, they have to be examined in more detail. CEA Ejection is considered in section 15.4.3.2 of the FSAR. In those cases where the CEA Ejection is considered in conjunction with a break in the RCS, the maximum RCS pressure is essentially unchanged from initial conditions. Since secondary pressure will only increase, the pressure differential seen by a steam generator tube will not increase as a result of the event and it is therefore not credible that such an event could cause a concurrent tube rupture. In the case of a CEA Ejection with no RCS break, RCS pressure rises about 300 psia with steam generator pressure remaining essentially constant. In the zero power case, steam generator pressure will be 100 psia higher than at full power so the maximum pressure differential in a zero power CEA Ejection accident is only slightly higher than what is seen during normal full power operation. This case is bounded by the full power case. For a tube to rupture as a result of a full power CEA Ejection without RCS break at full power, its minimum wall thickness would have to be below 5.6%. Since we know that the debris in question did not exist in the generators prior to the start of Cycle 5 and since none of the generator tubes have wear in the area where debris could cause wear, the average rate of wear would have to be about 0.6% tube thickness per day. For a tube to be in the region where it has not failed in normal operation but will fail in a CEA Ejection accident, it must be the tube with the most wear and have a minimum wall thickness of between 5.6% and 4.1%. At the average wear rate, this could only exist for 2.5 days. Given that there is no known mechanism that would cause a CEA Ejection without RCS break, such an event is hardly credible in itself. The possibility of such an event occurring in the 2.5 day interval in which the most badly worn tube might possibly be in a condition which would allow it to rupture during the event is so remote that the combined event is not credible. If some tube leakage were to be assumed, the consequences of the accident would be mitigated but the very low activity level in the primary and secondary systems and the fact that the actual core neutronic parameters are much less restrictive than those assumed in the accident.

The RCP sheared shaft event is analyzed in section 15.3.3 of the FSAR. RCS pressure rises in this event due to the increase in RCS temperature resulting from a decrease in RCS flow. RCS pressure rises by 118 psia. Steam generator secondary pressure at the time of maximum RCS pressure is about 10 psia lower than its initial value in the affected generator. Thus the differential pressure increase associated with this event is about 130 psid. This small change in differential pressure would not be expected to cause a weakened tube to rupture. A tube with a minimum wall greater than 4.7% should not rupture. Given the average wear rate assumed above, the time needed to go from 4.7% to 4.1% minimum wall is only one day. The probability of having a sheared shaft event in the one day period where the most badly worn tube is potentially susceptible to rupture is clearly too small to be considered credible. Once again, if some tube leakage did occur, the consequences would be mitigated by the very low activity in the primary and secondary systems and the fact that the actual core neutronic parameters are much less restrictive than those assumed in the accident.

Administrative Actions:

Although serious damage to the steam generator tubes is unlikely, several administrative actions have been taken. All operating crews will be provided with this safety evaluation so that they are aware of the situation. The Condenser Air Ejector Radiation Monitor has been set so that it will cause a control room alarm if tube leakage exceeds 30 gallons per day with no more than a 15 minute processing delay. Should that alarm occur, Chemistry will take confirmatory samples and begin trending air ejector activity. They will also monitor blowdown activity. The operators will be instructed to begin an orderly plant shutdown if the leakage rate trend indicates that leakage will exceed 200 gallons per day within the next 8 hours.

Chemistry has been directed to notify Operations and Station Technical should they see an RCS sample on Unit 2 with activity higher than 0.05 μCi/cc Dose Equivalent Iodine. Station Technical will re-evaluate the RCS conditions and determine if continued operation is justified. Operations will maximize letdown flow and return the RCS to less than 0.05 μCi/cc DEI within 48 hours or begin to shutdown.

Although tube ruptures on analyzed accidents are not considered credible due to the short time frame in which such a rupture potential could exist, Combustion Engineering has recommended decreasing COLSS DNBR margin by 5% to ensure that negligible fuel failure would occur in those limiting transients described above. This margin reduction will be implemented. Current COLSS DNBR margin is ~8.5%, so it should remain possible to operate 100% power even with this penalty. A suitable alternative would be to modify the CPC Variable Over-Power trip to be more conservative by 5% instead.

Conclusion:

The type of sparger damage seen in Unit 3 may exist in Unit 2. If it does it will not affect the ability of the plant to operate safely or for equipment important to safety to operate. The potential Unit 2 sparger damage will not create the potential for a damaging water hammer. The sparger mechanical support remains adequate. Possible debris will not affect down stream systems. The thermal stresses generated due to unequal feedwater flow distribution are acceptable. The ability to use auxiliary feedwater remains unchanged.

Based on the analysis above it is concluded that it is very unlikely that possible debris in the Unit 2 steam generators would cause tube damage of a type which could result in a tube rupture without significant prior leakage. Even if such damage should exist, the consequences of any accident would remain bounded by the current analysis. In any accident where fuel failure does not occur, the consequences remain bounded because of the very low primary and secondary activity levels currently in Unit 2. In accidents which do not significantly increase the pressure differential across the tubes, there is no mechanism for causing the weakened tube to fail during the event. In all cases the time interval over which a tube could be sufficiently strong so as to not have leaked but such that it could be sufficiently weak to rupture during a limiting fault condition is extremely small and thus the probability of the simultaneous occurrence of such a condition with an additional tube rupture is not credible. It is true, however, that debris could increase the probability for a single tube failure. It is concluded on the basis of industry experience with debris in steam generators and on the basis that it is very remote for the debris in Unit 2 to cause a tube rupture without there first being significant prior leakage is remote enough to justify continued operation for a limited time of

about 5 weeks. Combustion Engineering has concurred with this conclusion. Westinghouse has concurred that industry experience would conclude that a tube rupture event as a result of the debris potentially in the Unit 2 steam generators is remote.

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