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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SOUTHERN CALIFORNIA EDISON COMPANY

STEAM GENERATOR INSPECTION PROGRAM AND RETURN TO POWER REPORT (SEPT. 1982)

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT NO. 1

DOCKET NO. 50-206

1.0 INTRODUCTION

On February 26, 1982, following 4.3 effective full power months of operation from the start of Cycle 8 operation, San Onofre Unit 1 was shut down as scheduled in order to perform required tests, plant modifications and steam generator inspections. By letter of September 21, 1982, the licensee submitted a report entitled, "Steam Generator Inspection Program, Return to Power Report, San Onofre Nuclear Generating Station, Unit 1, September 1982." Also contained in the report is the additional information which was provided during the May 12, 1982 meeting in response to the NRC letter dated March 11, 1982 related to the steam generator sleeving repair program. The report describes the program of steam generator inspections performed during the outage, including individual inspection scope, findings, corrective actions, and conclusions; plans for return to power; and future inspection plans.

The steam generator inspection program addresses: (a) inspections implemented pursuant to San Onofre Unit 1 Provisional Operating License (POL) DPR-13 License Condition 3.E and Technical Specification 4.16, and (b) secondary side foreign materials and loose parts inspections. License Condition 3.E was reinstated by issuance on June 8, 1981 of Amendment No. 55 to the San Onofre Unit 1 POL. As such, the steam generator inspection required by Condition 3.E is the direct consequence of the program of steam generator diagnostics and repairs performed at San Onofre Unit 1 during the 1980-81 outage and reported by the licensee in the following references:

(1) Steam Generator Repair Report, Revision 1, March 1981, San Onofre Unit 1.

(2) SCE (K.P. Baskin) letter to NRC (D.M. Crutchfield) transmitting report entitled "Technical Evaluation Report of a Hybrid Joint," March 1981, San Onofre Unit 1.

(3) Steam Generator Repair Program, Return to Power Report, April 1981, San Onofre Unit 1.

The License Condition 3.E inspections performed during the current outage which began on February 27, 1982 focused on sleeved tubes over their sleeved lengths and on the region at or near the top of the tubesheet on the inlet side for non-sleeved tubes. This inspection is referred to as the Sleeving Repair Inspection.

In conformance with Technical Specification 4.16 provisions on frequency of inspections, an inspection was performed this outage addressing Technical Specification requirements on general surveillance of tube bundles and on special surveillance of anti-vibration bar (AVB) area wear, progression of denting, and other previously detected tube degradation. The last such inspection was completed in July 1980. This inspection is referred to as the Technical Specification Inspection.

Recent industry experience has demonstrated the potential for and consequences of foreign materials and loose parts being introduced into steam generators. In view of this experience, a secondary side foreign materials and loose parts inspection was initiated during the current steam generator inspection outage. A similar such inspection focusing on the primary side coolant loops was performed in conjunction with steam generator repairs made during the 1980-81 San Onofre Unit 1 sleeving repair project. This specific steam generator secondary side inspection is referred to as the Foreign Materials Inspection.

Three broken wrapper support bars (WSB's) approximately two inches in diameter and six inches long were found by video inspection and removed from steam generator "A". There is one intact wrapper support bar in steam generator "A" and two missing bars which the licensee could not

locate. In addition, one of the welds attaching the upper portion of one of the intact broken wrapper support bars to the wrapper is fractured. Steam Generator "B" had two fractured wrapper support bars (removed), two intact support bars, one missing bar, and one was undetermined because of the difficulty of video scanning at the location. No fractured or intact wrapper support bars were found in steam generator "C"; however, upper sections of the support bars at the welds were observed to be intact. The licensee has concluded that the missing bars were previously removed, most probably during manufacturing. In addition to the wrapper support bars, metal shavings, and other miscellaneous pieces of metal were located and removed from the steam generator.

Lastly, at the next and subsequent refueling outages, the secondary sides of steam generators A and B will be visually inspected to determine the condition of intact wrapper support bars. At that time the staff will determine if a return to the standard inspection interval of each refueling outage (approximately 15 EFPM) is justified.

2.0 SLEEVING REPAIR INSPECTION

In response to NRC concerns and because of improvements in inspection techniques identified during the course of the inspection, changes were made to the originally proposed program described in the licensee's letter of January 22, 1982. In summary, the inspection program consisted of the following elements:

- Tube bundle pressure and leak tests to demonstrate margin to normal operating conditions and to identify leaking tubes.

- Eddy current testing by conventional, multi-frequency, bobbin coil techniques of approximately 10% of the sleeved tubes in each steam generator to assess the integrity of sleeve-tube assemblies.

- Eddy current and ultrasonic testing of leader-follower sleeve-tube assemblies, pre-selected during the 1980-81 repair outage, to assess the susceptability to corrosive degradation of brazed joints.

- Eddy current testing of approximately 30% of the tubes outside the sleeving repair boundary on the inlet side of each steam generator utilizing multi-frequency, surface riding coil techniques to assess the extent to which intergranular attack (IGA) is occurring at the top of the tubesheet.

2.1 Primary to Secondary Tube Bundle Integrity Test

During the course of unit shutdown, with the unit in a hot shutdown condition a differential pressure of 1900 psid was established from the primary to secondary sides of the steam generators similar to the procedure employed during the 1980-81 repair outage. This differential pressure approaches that which might be expected following a main steamline or feedline break and serves to indicate overall tube bundle structural integrity and demonstrate gross margin over normal operating conditions for sleeved and non-sleeved tubes.

No problems were encountered in maintaining differential pressure and the test was satisfactorily concluded.

2.2 Cold Secondary Side Leakage Test

Following the primary to secondary side differential pressure test, with the unit in cold shutdown, a secondary to primary side pressure test at 800 psid was performed to identify any leaking tubes. As a result, three sleeved tubes exhibited minor leakage (one to two drops per minute) on the inlet side of steam generator C.

Each of these sleeve-tube assemblies was a leak limiting sleeve as described in Reference 2. The minor amount of leakage observed was assessed to be bounded by the allowable leakage for such sleeves. The source of leakage was attributed to the pre-existing IGA in two of the tubes while no determination was made for the other. It is noted that the amount of primary to secondary leakage observed during operation prior to the current outage was quite low, and in the range of the threshold of detectability for such leakage. As a corrective measure, all three tubes have been plugged.

2.3 Sleeved Tube Eddy Current Inspection

The inspection plan consisted of inspecting approximately 10% of the sleeved tubes within the sleeving repair boundary of each steam generator from the inlet side through the first support plate. Tubes were selected for inspection in a pattern of every third row and column adjusted, as necessary, to ensure that a representative number of all types of sleeve joints were inspected. The inspection was performed using a magnetically biased conventional bobbin probe with multi-frequency techniques, consistent with the 1981 post-sleeving baseline inspection.

In the inspection, eddy current signatures obtained were compared to the corresponding signatures from the 1981 baseline inspection. Sleeves exhibiting deviations from baseline data were subject to further evaluation on a case-by-case basis. Expansion of the basic inspection pattern to other sleeved tubes depended on the nature and extent of deviations identified. The plugging criteria of the Technical Specification were applied. With the exception discussed below, in all cases the signatures obtained in this outage appeared unchanged from those obtained during the 1981 baseline inspection.

In each of the sleeves inspected, a new eddy current signal was observed in the upper transition region(s) of the sleeve joint(s). These signals resulted from the presence of magnetite in the annular gaps between the sleeve and tube at and above the upper transitions of the sleeve expansion zones. It is suspected that magnetite grit was deposited on tube walls above the sleeves, as a result of the channel head decontamination process performed during sleeving, and collected in the gaps during the subsequent plant operations.

No deviations in eddy current signal characteristics at the sleeve joints and transition regions were observed. In the sleeve lengths outside the joint regions, no indications of degradation were observed. Since there is no evidence of corrosive attack of the sleeve-tube assemblies occurring, no repairs to sleeved tubes were required.

2.4 Leader-Follower Program

This program is designed to monitor in-situ leak tight braze joints for the formation of potential leak paths across the circumferential band of bonded braze material due to corrosive degradation when exposed to secondary side environmental conditions. The basis for such monitoring is that, unlike tube or sleeve wall degradation, small leak paths which may be developing across the braze region during operation are not necessarily detectable by eddy current techniques alone. Supplementary inspection by UT and continued monitoring of brazed joints preferentially exposed to potentially corrosive conditions will give early warning of susceptibility to leak path formation.

During the 1980-81 outage, tubes to be repaired with brazed sleeves were selected and deliberately penetrated through wall in the region to be spanned by the sleeves, thereby ensuring exposure of the brazed joint to

secondary side conditions upon resumption of operation. These tubes were designated as the "leader" tubes. Neighboring tubes which were fitted with leak tight brazed sleeves and known to have no through wall tube penetrations were designated as the control or "follower" tubes. Both leader and follower tubes were inspected by ECT and UT during the 1981 baseline and those exhibiting normal eddy current and UT signatures for leak tight joints became the final leader-follower tubes.

The program calls for re-inspection of leader-follower tubes by ECT and UT during subsequent outages and comparison of data with baseline data to determine whether significant changes have occurred. If significant degradation is suspected in a leader or follower tube in the brazed region, then the tube is removed for metallurgical examination. Appropriate additional evaluations and corrective measures are then identified.

For each leader and follower tube, both the eddy current and UT data showed no changes in comparison to data obtained during the 1981 baseline inspection. During the cumulative 4.3 EFPM of operation since the baseline inspection, a number of cycles of unit start-up and shutdown occurred which should have established representative secondary side conditions in the tube-sleeve annuli of leader tubes. Absence of any indication of change in the braze region during the current inspection suggests that no aggressive attack is occurring as a result of exposure to secondary side conditions. This is consistent with laboratory findings reported in Reference 1.

2.5 Non-Sleeved Tube Inspection

This inspection was performed to monitor peripheral, non-sleeved tubes on the inlet side of each steam generator for IGA at the top of the tube sheet. The basic inspection pattern for each steam generator consisted of all non-sleeved tubes which lie within either two rows or columns of the sleeving repair boundary, plus every fourth row and column in the remainder of the periphery.

In addition, areas in the periphery, where previous eddy current data indicated the potential for IGA activity, were also inspected. The primary inspection technique consisted of a screening inspection through the first support plate using a multi-frequency, push-pull probe with surface riding coils, known as a "4 x 4" probe. The probe consists of upper and lower sets of four series-wound surface riding coils. Each set produces absolute signals which are then differentially analyzed. This inspection was supplemented by multi-frequency bobbin coil inspection of each tube to assist in the interpretation of 4 x 4 data. Tubes with suspected IGA indications at the top of the tube sheet by 4 x 4 probe were then inspected using the RPC probe, as employed during the 1980-81 outage, to confirm whether IGA indications are present. Expansion to tubes surrounding those with IGA indications was done using the 4 x 4 probe until tubes with IGA indications were bounded by tubes having no IGA indications. The criteria for plugging non-sleeved tubes were (a) any tube with RPC-detectable indications at the top of the tube sheet, (b) any tube immediately adjacent to an RPC indication greater than or equal to 50% and (c) tubes within a broad boundary formed by tubes with IGA indications and tubes adjacent to tubes with IGA indications.

2.5.1 Staff Evaluation

A total of 1212 tubes from the total of 3985 peripheral, non-sleeved tubes in all three steam generators, for a combined percentage of 30%, were inspected. Within the population of 1212 tubes inspected, there were 8 tubes, or less than 1% having possible IGA indications which were not previously observed. Of these 8 tubes, the one in SG-A was evaluated from 4 x 4 data as being marginal with respect to a possible IGA indication and, as noted above, was not inspected by RPC. This tube is, however, located adjacent to the sleeving boundary in a region of possible IGA activity based on previous inspection results.

Of the remaining seven in SG-C, only one, located adjacent to the sleeving boundary, had a quantifiable indication (40%). The other six, located adjacent to or, in one case, two tubes from the sleeving boundary, had very small indications which could not be discretely quantified and were evaluated as <20% indications.

In the 1980-81 outage (Reference 3), the rate of IGA progression in the so-called "active" region was conservatively estimated to be 15% per year of operation in the following way: A degradation rate of fifteen percent per year was qualitatively predicted by comparing the eddy current signatures of thirty-nine tubes obtained during inspections in 1976, 1977, 1978 and 1979 with those obtained in 1980. Since the eddy current signatures obtained in 1976, 1977, 1978 and 1979 were only reported as either distorted tubesheet signals or distorted dent signals, degradation values were assigned to each of the signatures, in retrospect. By inference from the results of the 1980-81 steam generator inspection results, if IGA or cracking was occurring at the top of the tubesheet in 1976 and it was sufficiently deep to be detected, then it was assigned a value of fifty percent penetration, and then the eddy current signatures in subsequent years were assigned values based on the observed change in the signatures, again in retrospect. After assigning the degradation values, the average rate on a per year basis for the thirty-nine tubes was determined to be thirteen percent per year. This was considered conservative since the eddy current signatures going back to inspections performed as early as 1973 were similar to those obtained in 1980-81, suggesting that the degradation was present even then. For the purpose of establishing the time for the previous inspection interval of six months, a corrosion rate of 15% per year was assumed to apply to peripheral tubes. For the determination of the next inspection interval, the Licensee has not been able to demonstrate that the corrosion rate is less than 15% per year; therefore, a future operation period of no more than six EFP months, as established previously based on a corrosion rate of 15% per year, is justified.

In light of the above considerations, the staff concludes that the above assumptions are conservative regarding degree of IGA penetration in peripheral tubes and its rate of progression. As such, the repair criteria invoked in both the 1980-81 and current outage continue to be regarded as adequately conservative.

2.5.2 Corrective Actions

The repair criteria stated above were applied to the inspection findings. As a result of these criteria, one tube in SG-A was plugged; in SG-C, seven tubes were plugged due to IGA indications and an additional 13 adjacent tubes were plugged in response to the broad boundary plugging criterion. In addition, one tube in SG-B was plugged due to a wastage type thinning indication above the top of the tube sheet.

2.5.3 Conclusions

The following conclusions are made regarding the sleeving repair inspections:

(1) Leakage observed from tubes with leak limiting sleeves during the secondary side leakage test is consistent with low level primary to secondary leakage observed during plant operation prior to shutdown. It is also consistent with allowable leakage design margin for leak limiting sleeves and limits as stated in the Technical Specification.

(2) Based on results of eddy current examination of sleeve-tube assemblies, no detectable structural changes were observed in sleeves or sleeve-to-tube joints.

(3) Based on results of the leader-follower tube inspection program, no changes were observed in braze material as a result of exposure to secondary side environment.

(4) NDE results for sleeve-tube assemblies and satisfactory completion of the 1900 psid primary-to-secondary differential pressure test indicate no detectable change to the primary pressure boundary as formed by the sleeve-tube assemblies. It also indicates that the margin of safety for continued operation is thereby maintained and consistent with that set forth by the staff's Safety Evaluation Report, dated June 8, 1981, which evaluated the SCE Sleeving Project, Return to Power, and Repair Report (Reference 1).

(5) Based on the results of the eddy current inspection in the periphery of the steam generators, the satisfactory completion of the primary-to-secondary differential pressure test, and the secondary side leakage test, it is concluded that the extent and rate of progression of IGA in peripheral non-repaired tubes are conservatively bounded by the rate of degradation assumed for these tubes as set forth in the SCE 1981 Repair Report (Reference 1). The staff, therefore, believes that the basis for the repair boundary established in 1981 is still adequately conservative as stated in our previous Safety Evaluation Report, dated June 8, 1981.

3.0 TECHNICAL SPECIFICATION INSPECTION

The previous Technical Specification inspection was performed in all three steam generators beginning in April 1980. The results of that inspection and earlier inspection indicate that the pattern of denting in SG's A and C is unchanged and that in all other respects the three steam generators are behaving in a like manner. Consistent with Technical Specifications provisions, one steam generator (SG-C) was selected for inspection at this outage.

3.1 General Inspection

The program consisted of inspection from the hot leg through the U-bend to the 4th support plate on the cold leg of at least 3% of the total number of steam generator tubes plus inspection through the first support plate of tubes having previous wastage indications above the top of the tube sheet. Multi-frequency techniques with the conventional bobbin coil were employed.

No imperfections were found in SG-C requiring supplementary inspections. However, as a result of the pluggable wastage indication in SG-B, additional inspections were performed in SG-B of randomly selected tubes and tubes with previous indications of wastage. Wastage data obtained from SG-A hot leg during the supplemental bobbin coil inspection of non-sleeved tubes were also evaluated. In order to characterize the extent of cold leg wastage occurring in the steam generators, an additional inspection was performed in SG-A cold leg. As a result of these additional inspections, no further pluggable indications and no significant changes to previous indications were found.

Wastage indications observed in each steam generator at this outage were compared to corresponding indications from the previous inspection in 1980. The results indicate no significant change in the amount of wastage that is occurring. However, one tube in SG-B was plugged due to a 55% wastage indication.

3.2 AVB Inspection

Tubes having previous indications of AVB wear were inspected from either the hot leg or cold leg side depending on accessibility limitations due to restricted or sleeved tubes. Multi-frequency, conventional bobbin coil eddy current techniques were employed. No new indications of AVB wear were found and no significant changes to previously identified indications were observed.

3.3 Denting Inspection

Tubes which were previously identified as being restricted in steam generator C hot leg were gauged through the fourth support plate using eddy current probes. Due to the presence of sleeves, access to support plate restrictions was made from the cold leg for certain tubes. Any tube restricting passage of a .460 probe was plugged and the neighboring tubes were also gauged until no restrictions were noted in the surrounding tubes. Restriction sizes observed at this outage were compared to previous inspection results to assess the progression of denting.

Photographic inspections of the upper support plate flow slots of SG-C and the lower support plate flow slots of SG-A and SG-C were also performed to assess the progression of flow slot hourglassing. In addition, photographs were taken of lower support plates in SG-B to verify the continuing absence of hourglassing in that generator. Upper support plate inspection of SG-C was accomplished through a 3-inch inspection port located above TSP #4 and aligned with the tube lane. Lower support plate inspections were accomplished through the secondary side hand holes above the tube sheet on either end of the tube lane.

Photographic inspection of upper support plate flow slots showed no evidence of flow slot hourglassing, consistent with the finding of previous inspections that hourglassing due to in-plane expansion of the tube support plates is confined to the lower support plates (TSP's 1 and 2) in SG-C. Available information indicates that this is the case in SG-A as well. Photographic inspection of lower support plate flow slots in SG-A and -C showed no change in the extent of flow slot hourglassing and tube support plate cracking in comparison to previous inspection results. Continuing absence of flow slot hourglassing and support plate cracking was verified in SG-B. Enhanced photographic inspection techniques employed at this outage

did, however, disclose the possibility of cold leg restrictions in steam generators A and C which had not been previously identified. As a result of these photographic inspection findings, gauging programs were developed and implemented for the cold leg sides of SG's -A and -C in order to determine the location and size of restriction not previously identified.

Comparison of tube gauging data at this outage with corresponding data from previous inspections indicates no pattern of increased restrictions attributable to a significant progression of the denting process. In SG-C, for instance, 5 tubes were restricted to a probe size that previously passed, while 16 tubes passed a probe size that was previously restricted. The licensee concluded that these results are less indicative of progression of denting than they are of artifacts of the gauging process.

With respect to the cold leg gauging findings, restrictions are fewer in number and less severe than hot leg restrictions. Also, restrictions are associated with support plate "hard spot" locations, consistent with the pattern previously observed on SG's -A and -C hot legs and in other units with denting experience.

These gauging results coupled with the photographic inspection results of flow slots indicate that significant progression of denting is not occurring at San Onofre Unit 1. One tube in SG-A and three tubes in SG-C, which were restricted to a .460 probe, were plugged.

3.4 Fretting and Wear of Support Plates

The conditions of the lower support plates in SG's -A and -C have raised questions concerning the possibility and consequences of tube degradation because of fretting and wear at support plate locations.

Fretting is the mechanical removal of metal, which occurs slowly and is associated with small relative motions of contacting surfaces. On alloys which have a passive surface film, such as Inconel 600, fretting in the presence of an otherwise noncorrosive aqueous medium can remove the film, resulting in a slight amount of metal dissolution or corrosion, a process which is continually opposed by the relatively rapid repassivation kinetics. Nevertheless, over a great many cycles, significant amounts of metal can be removed by the combined processes of mechanical action and incremental corrosion. Fretting may therefore be considered as a form of corrosion-assisted wear.

A potentially more serious form of degradation of steam generator tubing is wear. Wear differs from fretting mechanistically in that the geometrical conditions causing wear require a relatively long distance of relative motion of the contacting surfaces, with little or no accumulation of detritus from the wear. Fretting typically occurs under both lower magnitudes and lower rates of relative movement than wear. Wear is not notably increased by the presence of an aqueous environment (which can sometimes even act as a lubricant), whereas fretting can be accelerated (by fretting corrosion) by the environment. A low wear rate, however, generally results in a higher amount of metal removal than a high fretting rate.

Based on experience, neither wear nor fretting has been identified at support plate intersections in the San Onofre steam generators. To add to this experience base, a special eddy current inspection was done on a number of cold leg tube lengths in SG-C which are at or near cracked support plate locations as determined from photographs. The purpose of the inspection was to seek evidence of fretting at the first and second support plate intersections. No fretting or wear indications were recorded at these support intersections.

During the mid-1970's a fretting/wear type of degradation was identified in San Onofre steam generator tubing at the contact points of the large radius U-bends with the original-design, round, steel anti-vibration bars (AVB's). The degradation was arrested by the installation of new, flat-surfaced, Inconel 600 AVB's. The favorable performance of the new AVB's over the last 5 years indicates that fretting or wear at U-bends does not appear to be a problem.

In summary, fretting is a slow process, heretofore not experienced at support plate intersections in steam generators of the Westinghouse Series 27, San Onofre 1 design. If the slow development of fretting proceeded to a depth in excess of 20% wall penetration at an undented intersection, it would be detectable by eddy current and subject to periodic monitoring by ECT. The metal removal in fretting or wear as a result of tube support plate interaction would be a localized process, both axially and circumferentially. Any complete wall penetration by a fretting or wear-related process would remain highly localized with limited propagation by tearing.

3.5 Evaluation of Technical Specification Inspection

Based on the results of the Technical Specifications Inspection, it appears that there are no significant active corrosion, fretting or wear processes occurring in the San Onofre Unit 1 steam generators. In particular, significant progression of denting and of AVB wear is not occurring, nor is there evidence of fretting occurring at tube and support plate intersections.

4.0 FOREIGN MATERIALS INSPECTION

A general inspection was initiated by the licensee during the current outage to locate and retrieve any previously unidentified foreign materials and loose parts on the secondary side of each steam generator. An additional effort was also launched to locate and retrieve a self-reading dosimeter which was dropped into the upper internals of SG-A while making modifications to the moisture separators during the current outage.

In summary, the foreign materials inspection program at this outage consisted of the following elements:

- Full circumference visual inspection in each steam generator of the annular region between the tube bundle and shell at the top of the tube sheet.

- Visual inspections of the tube lane of each steam generator.

- Secondary side visual inspection in SG-A to locate the dosimeter inadvertently dropped into the upper internals during current outage moisture separator modifications.

- Retrieval of foreign material.

Primary pathways for the introduction of foreign materials into the secondary side are the secondary manway, the secondary handholes and, in SG-C only, the inspection port above the fourth support plate. Materials can also be introduced through the various nozzles, particularly the feedwater nozzle. It was judged that the most likely areas for materials to migrate into potentially damaging contact with tubing are the upper bundle region above

the fourth support plate and the top of the tube sheet. Of these areas, the upper bundles of all steam generators were inspected for foreign materials in conjunction with the AVB modifications during the 1976-77 outage. A special upper bundle inspection was developed for SG-A at this outage to locate and retrieve the dropped dosimeter. Hydraulic conditions which would promote interaction between steam generator tubing and foreign materials are more likely to occur at the top of the tube sheet where downcomer flow is directed radially inward toward the tube bundle. Personnel and equipment access and ALARA considerations were weighed by the licensee in deciding on the location and extent of regions within the steam generators to be inspected. Based on these considerations, the top of the tube sheet regions in each steam generator was selected for performance of the general Foreign Materials Inspection. The staff finds this to be acceptable.

Visual inspections were accomplished using skid mounted TV cameras. For the annular inspection, geometrical constraints limited camera lighting and available view angle to the diagonal field of view associated with straight viewing. Right angle viewing was achievable for the tube lane inspection only.

Foreign objects were removed using either a magnet or a grappler. Small particles, loose sludge and magnetite deposits were removed using a vacuum system. Following retrieval and vacuuming efforts, a final visual inspection was performed to ensure that all foreign objects were identified and removed as required. In the case of the dropped dosimeter in SG-A, a direct visual (no TV) inspection of the top of the tube bundle was performed through the swirl vane assembly. The dosimeter was located and was removed using a magnet.

The staffs conclusions regarding the foreign materials inspection are provided in the next section, along with conclusions on the wrapper support bar investigation.

5.0 WRAPPER SUPPORT BARS

5.1 Introduction

The original design of each San Onofre Unit 1 Westinghouse Series 27 steam generator included 6 wrapper support bars welded to the base of the wrapper and threaded into the tube sheet. During the foreign materials inspection of each steam generator in 1982, a total of five wrapper support bars (WSB's), three in SG-A and two in SG-B, were found loose and lying on top of the tube sheet near their design locations. One WSB was found intact in SG-A and two WSB's were found intact in SG-B. Ten WSB's were missing from their original design locations -- two from SG-A, two from SG-B, and all six from SG-C.

5.2 Discussion

The original wrapper support design for the Westinghouse Series 27 steam generator included six symmetrically located and vertically positioned bars welded to the base of the wrapper on the ID and threaded into the tube sheet. The wrapper rested on these bars and the bars were intended to accept the vertical wrapper loads specified in the steam generator equipment specification.

Wrapper support channels were welded to the shell between the shell and wrapper to provide horizontal support for the wrapper. These channels were positioned every 90° about the wrapper circumference at each of the four tube support plate elevations.

In addition, the design of the wrapper and tube bundle support assembly was based on a tight fit between wrapper support channels and the wrapper to withstand horizontal shock and prevent movement of the tube bundle during rolling of the completed steam generator or during the welding of the lower shell assembly to the chamber and upper shell assemblies.

At the time of final shop cleanliness inspection of a Series 27 steam generator for another unit in April 1966, it was discovered that two of the support bars attaching the wrapper to the tube sheet were broken. Since all the SCE units were in the field at that time, it was necessary to implement the alternate wrapper support modification in the field. Installation of the three supports was accomplished at SCE in mid-1966.

A thorough review of the records on file was made by the licensee, directing particular attention at locating references or discussions of any inspections which may have been performed during this time frame and, in particular, any mention of inspection findings relative to the wrapper support bar conditions. No records were found that would account for the as-discovered condition of the SCE wrapper bars as noted in the inspections of May 1982.

The findings relative to WSB's prompted a thorough investigation of wrapper supports to determine the cause of the conditions observed and the appropriate corrective actions to be taken.

5.3 Wrapper Support Investigation

The Licensee's investigation consisted of the following:

- Full circumference visual inspection in each steam generator of the tube sheet to locate loose WSB's, locate and assess the condition of intact WSB's, and identify and examine locations where WSB's are missing.

- Retrieval of loose WSB's.

- Visual inspection of tubes in the neighborhood of loose WSB's in order to detect gross indications of damage which may have occurred to tubes due to possible tube-WSB interaction.

- Eddy current inspection through the first support plate of the outermost active peripheral tubes in each steam generator for evidence of tube degradation due to possible foreign material or WSB interaction.

- Metallurgical analysis of removed WSB's to characterize failure mechanisms.

- Flow tests to assess the potential for damaging interaction between loose WSB's and steam generator tubing.

- Structural analysis of modified wrapper supports and steam generators internals to confirm tubes integrity under accident (steam live break) and SSE loading conditions.

5.4 Evaluation

The historical background investigation found that WSB's in Series 27 steam generators were observed to be subject to failure during the manufacturing process. This observation led to field modifications of Unit 1 steam generators to include alternate wrapper supports. No records of inspections and/or removal of WSB's prior to the current outage have been located. Visual inspection of removed WSB's and original WSB locations showed similarity as to break locations at the threaded end and/or wrapper attachment piece.

Visual inspection of peripheral tubing in each steam generator, with particular attention to tubing adjacent to loose WSB's, showed no evidence of tube degradation. Eddy current inspection of peripheral tubes showed no evidence of significant tube degradation which could be correlated with tube interaction with WSB's. The plugging history of peripheral tubes showed no tube having been plugged due to indications of tube degradation between the tube sheet and first tube support plate.

Metallurgical analysis of removed WSB's indicated that fracture was due to a fatigue mechanism that occurred early in plant life. The fracture mechanism was common to all WSB's analyzed. Flow tests at a Unit 1 steam generator mock-up, utilizing a WSB removed from Unit 1, demonstrated that tube degradation due to WSB-tube interaction does not occur under simulated operating conditions. This is discussed further in Section 5.4.1.

With respect to the intact WSB's, the Licensee analyzed the possibility of removing them from the steam generators. SCE concluded that removal of the WSB's could not be accomplished without inordinate difficulty in light of technical, equipment access, inspection, and personnel exposure issues. They therefore, decided to leave the WSB's intact for the following reasons:

- The cumulative evidence from the wrapper supports investigation suggested that the observed conditions of intact, loose and missng WSB's have been in existence since the beginning of plant operation.

- There was no evidence of prior tube plugging repairs or currently noted tube degradation in active tubes having occurred due to interaction between tubing and WSB's.

- The absence of tube degradation attributable to interaction between tubing and WSB's during normal operation was supported by the results of the flow tests.

- Periodic secondary side inspections can be made in SG-A and B to observe the condition of WSB's and remove any which may have become dislodged.

5.4.1 Evaluation of Flow Tests to Assess Wrapper Support Bar - Tubing Interation

A full scale mockup of the lower tube bundle (wrapper inlet) region was constructed for the purpose of visually observing the mobility of "loose parts" that may exist in the SCE steam generator. The "loose part" tested was an actual "wrapper support bar" as found and removed from a SCE steam generator. The object was tested in cold flow (80°F) water at scaled flow rates of seven and eight feet per second. The hydraulic scaling of the test flow rates was designed to match the "Froude Number" and "Drag Forces" on the wrapper support bar at the prototypical conditions. The initial tests consisted of four tests followed by an additional three tests to investigate other similar geometrical configurations.

Test Description

A full scale test model was built to simulate the downcomer circuit of the steam generator. It included the wrapper inlet and the outer periphery of the tube bundle extending from the tube sheet to just above the first support plate. Test operating conditions were determined from dimensional analysis. This analysis considered inertia, pressure, viscous and drag forces to provide similitude of the test parameters between the model and prototype. Downcomer velocites of seven to eight feet per second in the model simulated 30% above normal operating conditions in the prototpye. The initial tests were designed to represent an upper bound condition with greater than normal crossflow in the tubebundle downstream of the wrapper inlet. This was accomplished by plugging all the flow circulation holes in the first tube support plate and forcing all of the flow through the rear flow resistance plate.

The test object was installed in the middle of the test vessel in an upright position that would represent the "as-built" installation. Flow was initiated and increased to an equivalent downcomer velocity of seven ft/sec. Just as flow reached seven ft/sec the object fell over and rolled up against the leading edges of the outer row of tubes. Once the object came to rest there was no further observable motion for the remainder of the test. The flow rate was then increased to an equivalent downcomer velocity of eight ft/sec. The object maintained its previous position up against the leading edges of the tubes with only an occasional flutter in which one end of the tube would roll back

less than 1/8 inch and then roll forward again. There was no observed impact against the tubes for the remainder of the test.

Several additional tests were conducted with the following objectives:
(a) To determine the mobility of the upper part of the SCE lower wrapper support bars. This portion of the lower support bar is normally welded to the lower part of the wrapper. Several initial positions of the above object were tested at downcomer velocities of seven and eight ft/sec and the original scoping test geometry.
(b) To investigate the flow field around the upper part of the lower wrapper support in its normal installed position (welded to wrapper barrel). Flow visualization and pitot-static probes were used to map the velocity direction and magnitude at several locations.
(c) To investigate the mobility of both the upper and lower parts of the wrapper support bar with the inclusion of a warped wrapper. This was to simulate the "as-found" condition of the wrapper. The net effect of the warped wrapper is to constrict the downcomer annulus resulting in locally higher wrapper inlet velocities.

Flow was initiated and increased to seven ft/sec. The object was observed to be in a constant state of motion. It would lift up approximately 1/8" - 1/4" on one end and then drop back down onto the tubesheet while maintaining sliding contact with the leading edges of the outer row of tubes. There were no observed impacts of the object against the tubes for the duration of the test.

The flow was increased to eight ft/sec and the test continued. At this flow rate, the object was still observed to be in a constant state of motion. It continued to lift up approximately 1/8" - 1/4" with occasional non-periodic lifts of 1" - 2". Once again there were no observed impacts as the object maintained sliding contact with the leading edges of the outer row of tubes.

Discussion of Test Results

The following inferences can be drawn from these test results:

(1) There were no apparent impact loads on the tubes generated by the wrapper support bar at any of the test conditions.

(2) The addition of the wrapper support in the annulus at the first tube support plate elevation did not produce any unfavorable local turbulence at the tube-sheet.

(3) Other than the initial repositioning of the upper wrapper support bar upon initiation of flow, there was no observed impact or sliding motion at any of the test conditions. Thus it would appear that this object would not be a mobile tube degrading mechanism.

(4) The addition of the warped wrapper resulted in increased local velocities at the tube bundle inlet. This was apparently significant enough to cause both the upper and lower wrapper support bars to exhibit increased mobility at seven and eight ft/sec downcomer velocities. However, there were no apparent impacts as the objects always stayed in sliding contact with the leading edges of the outer row of tubes.

Conclusion

The results of the flow tests for the purpose of assessing the behavior of loose WSB's under simulated steam generator normal, operating conditions and a 30% overtest condition indicate that a loose wrapper support bar would not cause damaging interations with the steam generator tubing.

5.4.2 Evaluation of the Structural Analysis of the Steam Generator Internals

A preliminary scoping analysis was performed to identify the regions of the steam generator internals where high stresses and possible large deformations may occur. Preliminary SLB blowdown loads and seismic loads acting on internals were generated as inputs to the analysis. The stress analysis of the modified wrapper supports and other internals was based on elastic calculations.

The results of the preliminary scoping analysis also indicated that the most limiting components were the wrapper support brackets and the wrapper shell at the bracket attachment location. The primary and conservative assumption made in those calculations was that the total SLB load on the lower shell internals was applied to the wrapper support brackets. The resulting bracket deformations caused by these loads were very large. In order for these deformations to occur, the tube support plates would have to slide along the tubes in a uniform manner in order not to load the tubes. The last assumption was very unlikely due to the eccentricity of the loads being applied to the tube support plates. Therefore, the interactions between the tubes and the support plate was investigated in the detailed analysis. The major internal components in the upper shell were also reviewed to assure that any failure in this

region would not violate the primary pressure boundary. The preliminary analysis by its nature did not predict the manner in which loads are redistributed due to deformation and the resultant actual failure modes, if any, of internals. Actual failure modes were explored in separate detailed analyses discussed in the following paragraphs.

Evaluation of the SLB Analysis of Steam Generator Internals

A detailed steam-line break (SLB) analysis was performed by Westinghouse and discussed in Appendix C.3.2 of Reference 2. The objective was to determine the effect of the internals on the tube bundle primary pressure boundary under the influence of SLB faulted condition loads. The blowdown loads used in this analysis were generated by MPR Associates, Inc. The MPR analysis model, assumptions, and summary of results are contained in Appendix C.3.2, Volume I of Reference 1.

The Westinghouse analysis demonstrates that under the assumed conditions the internals behave so as to not affect the structural integrity of the primary pressure boundary. A summary of the Westinghouse analysis results are provided in Table 1. The location of each of the regions included in these analyses is presented in Figure 1.

Discussions of the SLB Analysis Results

The results presented in Table 1 demonstrate the SCE steam generator is capable of withstanding the SLB event. The analysis has shown that the

most significant loads were those associated with the tube bundle - wrapper region. These loads were found to be transmitted from the wrapper thorough the tube support plates to the tubes via the wedge welds and support plate/tube interaction. A small portion of the load was carried by the wrapper support brackets. This load was very small, however, due to the relative flexibility of the bracket/wrapper connection.

The wrapper tie down bars that are located at the bottom of the wrapper and attached to the tubesheet were not considered to be active in this analysis. Therefore, the tie down bars do not need to be intact. If they were assumed to be acting, however, the resulting tube loads would be less than those calculated in this analysis.

The internals in the upper shell were also investigated. It was demonstrated that any failure in that region would not adversely effect the primary pressure boundary.

The tube load distribution demonstrated a large variation in individual tube loads between the inner tube bundle region and the wedge region. This variation is due to both primary and secondary loads. The tube with the largest axial load (1134 lb) was located at the wedge on the circumference of the tube bundle. The assumed primary to secondary pressure difference across the tubes was 1200 psi. In addition, the flow-induced vibration analysis indicated a maximum tube bending moment of 386 in-lb. These three loads resulted in membrane and membrane plus

bending stresses of 33,026 psi and 85,831 psi, respectively, in a tube with 40% remaining wall. The minimum expected yield strength of the tube material is 42,100 psi. The yield stress is considerably less than the applied membrane plus bending stress. Therefore, the tubes with a significant bending moment (outside tubes) will yield and the load will be redistributed to the inner region of the tube bundle (elastic tubes). The local yielding will cause a shifting of either a portion or all of the secondary component of the total tube load. The actual displacement of a tube will be limited by the restraint of neighboring elastic tubes and the tube support plate. The secondary stresses need not be evaluated per Appendix F of the Code (2) for faulted conditions. The primary stress which is required to be evaluated is a value of 9,439 psi. This is less than the circumferential pressure stress (16,748 psi) and well within the yield strength of the material. Finally the average SLB tube load compares favorably with the average tube loads for the inner region of the tube bundle ranging from 18 lbs to 100 lbs.

Evaluation of SSE Analysis of Steam Generator Internals

A seismic analysis of the steam generator internals was performed to determine the effects of the internals on the tube bundle primary pressure boundary under the influence of the SSE faulted condition loads. The seismic loads were developed from work done separately by

Westinghouse and by R. L. Cloud and Associates as presented in Reference 1. In both cases, the seismic excitation upon which the loads were computed was based on the responses of the steam generator that were obtained from the previously documented seismic analysis of the primary system to the .67g Housner spectra in the San Onofre Unit 1 FSAR.

In the event of the safe shutdown earthquake (SSE), the steam generator internals are subjected to loads much greater than those during the normal operation of the unit. Since this event is a faulted condition as defined by Section III of the ASME Code, only those internal components which could affect the structural integrity of the primary pressure boundary were investigated. The regions which were most significantly loaded have previously been identified in the preliminary stress evaluation (Reference 3). The methods used in that analysis were used as basis for stress calculations in Reference 1.

The SSE loads considered in this analysis are presented in Table 3-2 of Reference 1. The loads were developed from work done by Westinghouse and R. L. Cloud and Associates. The vertical SSE components were developed by two independent models. One model used the response spectra method of analysis and the other used the time history approach. The SSE loads due to the horizontal components were calculated using the response spectra curves of Reference 5.

The normal operational loads acting on the wrapper support brackets included the components shown in Table 3-1 of Reference 1. Based on the

scoping calculations (Reference 3) the most limiting components were the wrapper support brackets and the wrapper at the bracket attachment location. These limiting components are loaded only by the seismic forces in the vertical direction. The contribution due to horizontal seismic forces are considered negligible at these locations. The horizontal loads are resisted completely by the bearing of the tubes, support plates, and wrapper on the shell guide bars.

The major internal components in the upper shell were also reviewed to assure that any failure in this region would not violate the structural integrity of the primary pressure boundary.

Discussion of SSE Analysis Results

The resulting maximum allowable loads and applied loads for several regions of the SCE steam generator internals are presented in Table 2. The results presented in Table 2 demonstrate the SCE steam generator is capable of withstanding the SSE event. The analysis has shown that the most significant loads were those associated with the tube bundle-wrapper region. These loads were found to be transmitted from the wrapper through the tube support plates to the tubes via the wedge welds and support plate/tube interaction. A small portion of the vertical load was carried by the wrapper support brackets. This load was very small, however, due to the relative flexibility of the bracket/wrapper connection.

The wrapper tie down bars that are located at the bottom of the wrapper and attached to the tubesheet were not considered to be active in this analysis. Therefore, the tie down bars do not need to be intact. If they were assumed to be acting, however, the resulting tube loads would be less than those calculated in this analysis.

The internals in the upper shell were also investigated. It was demonstrated that any failure in that region would not adversely effect the primary pressure boundary. The horizontal SSE loads associated with the tube bundle were found to cause localized tube deformations at the shell guide bars. The total reductions of primary flow area was found to be 39.8 square inches. The tube load distribution demonstrated a large variation in individual tube loads between the inner tube tube bundle region and the wedge region. This variation is due to both primary and secondary loads. The tube with the largest axial load (272 lb) was located at the wedge region on the circumference of the tube support plate. The assumed primary to secondary pressure difference across the tubes was 1200 psi. These two loads resulted in a maximum axial stress of 14,287 psi in a tube with 40% remaining wall. The minimum expected yield strength of the tube material is 42,100 psi. The average primary axial stress, S, was determined to be 8591 psi. This is less than the circumferential pressure stress (16,748 psi) and well within the yield strength of the material. Finally, the average SSE tube load compares favorably with the average tube load for the

inner region of the tube bundle ranging from 4 lbs to 24 lbs.
The above analyses demonstrates that the primary pressure boundary integrity is not affected by any failure of the internals under SSE conditions.

Conclusions

Based on a review of the structural analyses and model test data, the concludes:

A steam line break results in the most severe loading from the standpoint of WSB-tube interaction. During this short duration blowdown transient, flow is directed outward from the tube bundle at the top of the tubesheet. Thus conditions which would promote WSB-tube interaction are unlikely to occur during worst case accident conditions. Data from earlier studies, referenced in the subject report support the above conclusion.

The results of a preliminary stress analysis indicated those steam generator internals areas that may be subject to excessive loads and resultant large deformation under the steam-line break and SSE events. However, the analysis by its nature did not predict the manner in which the loads are redistributed due to deformation and the resultant actual failure modes, if such exist, of the intervals. These were investigated in separate detailed analyses. Results of these analyses demonstrate that under SSE or SLB faulted condition loads the structural integrity

of the primary pressure boundary is not violated. The major internal components in the upper shell were also reviewed and it was found that any failure in the region would not result in damaging interaction with the primary pressure boundary.

5.5 Summary of Corrective Actions

In summary, all identified foreign materials and loose WSB's were removed from the steam generator secondary sides. Intact WSB's in SG's-A and B were left in place. The alternate wrapper supports were accepted in their as-found conditions.

As a conservative measure, peripheral tubes with ID indications or restrictions in tube spans below the first support plate were plugged as follows: a) SG-A -- three tubes having ID indications, b) SG-B -- two tubes having ID indications, and, c) SG-C -- three tubes having restrictions.

The licensee committed to an in-depth review of foreign material control measures and a formal program addressing foreign material exclusion and inventory control to be implemented prior to performing further major work in the Unit 1 steam generators.

At the next and subsequent refueling outages, the secondary sides of steam generators A and B will be visually inspected to determine the condition of intact wrapper support bars. Inspection results will dictate appropriate corrective actions at that time.

5.6 Conclusions

Based on the results of the foreign materials inspection and wrapper supports investigation, the NRC staff concludes that significant tube degradation has not occurred due to the presence of foreign materials and loose WSB's.

6.0 Overall Summary and Conclusions

The Sleeving Repair Inspection was satisfactorily completed. The results provide evidence of tube bundle integrity, the effectiveness of sleeving repair and the adequacy of the repair criteria. Although eddy current inspection techniques employed have limitations, they are judged to be adequate for monitoring critical area of sleeved and non-sleeved tubes. Improvements in eddy current inspection techniques which are being developed by the industry should be pursued by the licensee and considered for application during future sleeving inspections.

With regard to IGA in the non-sleeved peripheral tubes, the collective results from the current and previous outage inspection programs and diagnostic studies indicate that the previously postulated extent and rate of progression of IGA and the associated repair criteria are conservative. Based on the prior discussion, the staff concludes that the probable failure mode for tubes with IGA at the top of the tube sheet is "leak before break." The allowable primary to secondary leakage limitations of the San Onofre Unit 1 Technical Specifications, imposed by the staff in 1981, would mandate unit shutdown to remove any leaking tubes from service before degradation reached an unacceptable level. Additionally, it is judged that under the conservatively assumed extent and rate of progression of IGA in the peripheral tubes, the eddy current inspections at inspection intervals of no greater than 6 EFPM, will detect IGA tube degradation prior to penetrating through wall.

The NRC staff concludes that the results of the Technical Specification Inspection strongly indicate the absence of continuing significant tube degradation processes related to tube wastage, AVB wear and denting, and of fretting at tube-support plate intersections. Were fretting to occur undetected, leak-before-break would apply. Given the likelihood of fretting at support plate intersections and the probable failure mode, fretting at the cracked support plate locations should not be a safety concern at San Onofre Unit 1.

The NRC staff concludes that all plugging repairs, required by the Technical Specifications as a result of this inspection have been completed. With regard to the foreign materials inspection, all loose materials were removed. The wrapper supports investigation indicated that no apparent tube degradation has occurred due to the presence of loose wrapper support bars on the secondary side over a number of years of operation.

7.0 Return to Power

At the conclusion of the previous outage, before return to power, the licensee implemented the revised secondary chemistry and steam generator soaking and flushing procedures. The licensee committed to continue to implement these procedures during startup and subsequent operation following the current outage. The staff concludes that these procedures should continue to be implemented.

With regard to the reduced primary temperature conditions, which were also implemented during the last outage, the licensee has indicated that insufficient data exist to reach definite conclusions as to their effectiveness in mitigating progression of IGA at San Onofre Unit 1. The licensee has indicated that it is intended to resume operation under these reduced conditions until otherwise warranted. As indicated in the NRC staff's safety evaluation dated June 8, 1981, the licensee is not prevented from returning to normal operating temperatures since this condition has been analyzed and found acceptable.

8.0 Future Inspections

Confirmatory inspection data will be obtained at each refueling outage following the current outage. At that time, a Technical Specification inspection incorporating sleeved and non-sleeved tubes will be performed. The inspection program will be similar to that performed during the current outage.

In addition, an in-depth review of measures relating to foreign material inventory, accountability, and control will be undertaken. Prior to commencing further major work in the steam generators in the subsequent outages, a formal Foreign Material Exclusion and Inventory Control Program will be implemented reflecting the results of the in-depth and incorporating appropriate administrative and positive measures to control foreign materials. This program will be applied to other equipment, as appropriate, in addition to steam generators.

9.0 Acknowledgement

This safety evaluation report was prepared by H. Conrad and J. Rajan.

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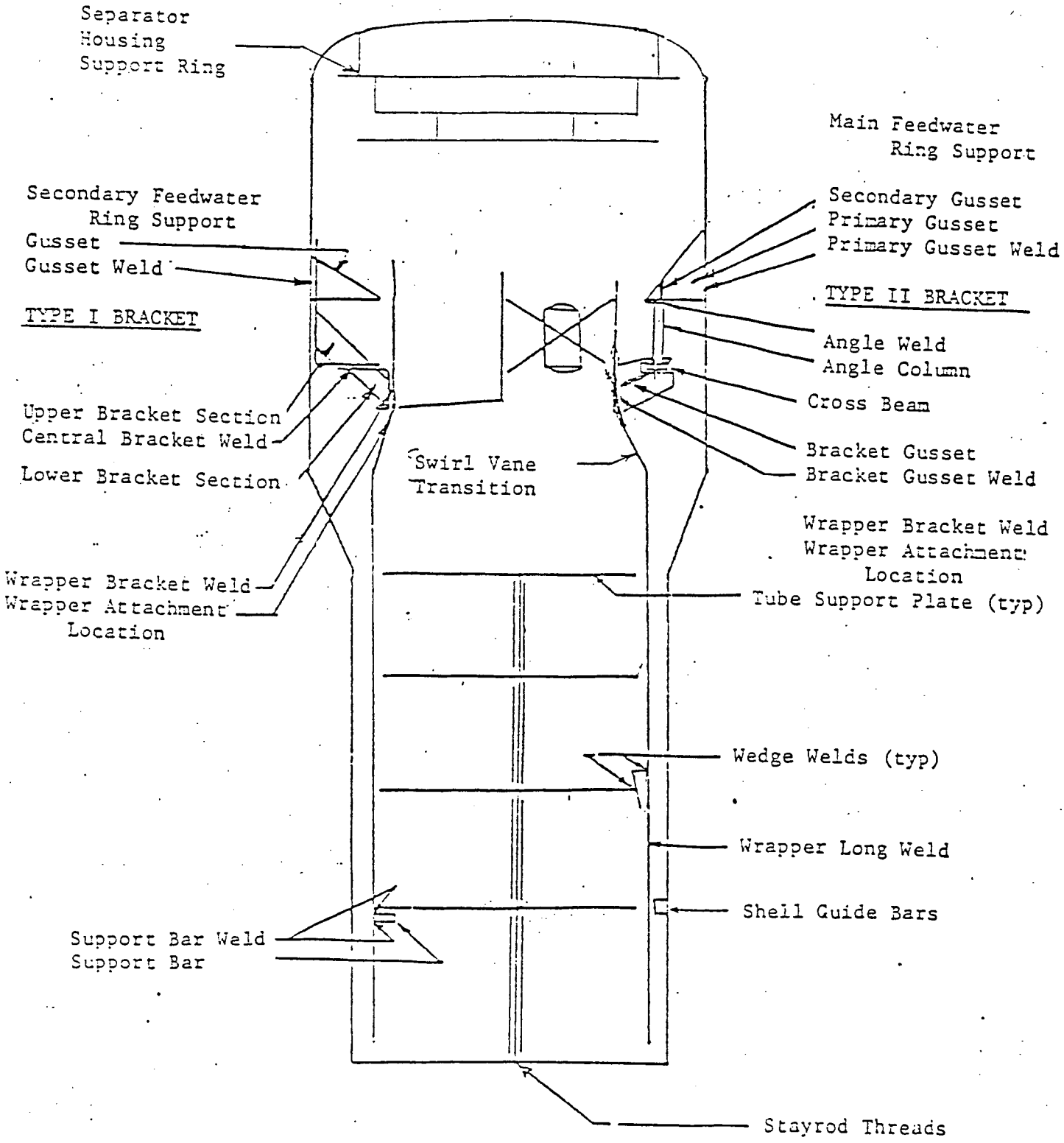

Figure 1

LOCATIONS EVALUATED FOR SLB AND SSE

RESU[illegible] OF STEAM LINE BREAK (SLB) ANA[illegible]SES

TABLE 1

Component	Location	Limit (2)	Applied Load	Load/Limit Ratio
Support Plate	Ligaments	77.8 ksi	40 ksi	.51
	Wedge Welds	8333 lbs	5116 Lb	.61
	Support Plate Rim	10163 lbs	5116 Lb	.50
	Support Bar Welds	2655 lbs	0	.00
Stayrods	Threads	30815 lbs	5196 Lb	.17
Wrapper	Long. Weld	25935 Psi	6,107 Psi	.24
Wrapper Bracket (Type I)	Wrapper Attachment Location	62.0 in-kip	42.6 in-kip	.69
	Wrapper Bracket Weld	6.4 kip/in	2.03 kip/in	.32
	Lower Bracket Section	37.11 kips	2.92 kips	.08
	Upper Bracket (1) Section	47.8 kips	2.92 kips	.06
	Central Bracket Weld	23.3 kips	2.92 kips	.13
Wrapper Bracket (Type II)	Wrapper Attachment Location	See Type I	--	--
	Wrapper Bracket Weld	See Type I	--	--
	Bracket Gusset Weld	14.9 kips	2.92 kips	.20
	Bracket Gusset	52.7 kips	2.92 kips	.06
	Cross Beam	17.5 kips	2.92 kips	.17
	Angle Column (1)	231.6 kips	2.92 kips	.01
	Angle Weld (1)	40.9 kips	2.92 kips	.07

TABLE 1 (con't)

Component	Location	Limit[2]	Applied Load	Load/Limit Ratio
Feedwater Ring Main Support	Secondary Gusset	63.34 kips	2.92 kips	.05
	Primary Gusset	54.4 kips	19.5 kips	.36
	Primary Gusset Weld	40.8 kips	19.5 kips	.48
Feedwater Ring Secondary Support	Gusset	77.19 ksi	32.6 ksi	.42
	Gusset Weld	57.9 ksi	32.6 ksi	.56
Swirl Vane Transition	Welds	25935 psi	6149 psi	.24
Separator Housing Support Ring	Weld	25935 psi	19337 psi	.75
Tubes	Tubesheet Region		49 Lb	---

NOTES:

(1) See Appendix A of Reference 1 for the slight decrease in allowable load due to the field variations.

(2) The limit was determined by using a criterion similar to Appendix F of the ASME Code Section III, 1980 Edition using ultimate strength values determined by experiment of that material or equivalent.

RESULTS OF SAFE SHUTDOWN EARTHQUAKE (SSE) ANALYSES

TABLE 2

Component	Location	Limit (2)	Applied Load	Load/Limit Ratio
Support Plate	Ligaments	77.8 ksi	9.6 ksi	.12
	Wedge Welds	8333 Lbs	1235 Lb	.15
	Support Plate Rim	10163 Lbs	1235 Lb	.12
	Support Bar Welds	2655 Lbs	0 Lb	.00
Stayrods	Threads	30815 Lbs	1248 Lb	.04
Wrapper Bracket (Type I)	Wrapper Attachment Location	62.0 in-kip	42.6 in-kip	.69
	Wrapper Bracket Weld	6.4 kip/in	2.03 kip/in	.32
	Lower Bracket Section	37.11 kips	2.92 kips	.08
	Upper Bracket (1) Section	47.8 kips	2.92 kips	.06
	Central Bracket Weld	23.3 kips	2.92 kips	.13
Wrapper Bracket (Type II)	Wrapper Attachment Location	See Type I	--	--
	Wrapper Bracket Weld	See Type I	--	--
	Bracket Gusset Weld	14.9 kips	2.92 kips	.20
	Bracket Gusset	52.7 kips	2.92 kips	.06
	Cross Beam	17.5 kips	2.92 kips	.17
	Angle Column (1)	231.6 kips	2.92 kips	.01
	Angle Weld (1)	40.9 kips	2.92 kips	.07

TABLE 2 (con't)

Component	Location	Limit	Applied Load	Load/Limit Ratio
Feedwater Ring Main Support	Secondary Gusset	63.34 kips	2.92 kips	.05
	Primary Gusset	54.4 kips	2.92 kips	.05
	Primary Gusset Weld	40.8 kips	2.92 kips	.07
Feedwater Ring Secondary Support	Gusset Weld	115.8 ksi	2.92 ksi	.03
Swirl Vane Transition		47.7 kips	16.2 kips	.06
Separator Housing Support Ring	Weld	4438 kips	75 kips	.02
	Attachment Bolts	176 kips	75 kips	.43
Tubes	Tubesheet Region		10 lb	--

NOTES:

(1) See Appendix A for the slight decrease in allowable load due to the field variations.

(2) The limit was determined by using a criterion similar to Appendix F of the ASME Code[2] using ultimate strength values determined by experiment of that material or equivalent.