VIRGINIA ELECTRIC AND POWER COMPANY

SURRY UNIT 2

REACTOR TRIP AND FEEDWATER

PIPE FAILURE REPORT

March 27, 1987

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SURRY UNIT 2 REACTOR TRIP AND FEEDWATER PIPE FAILURE REPORT

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I. INTRODUCTION

A. Brief Description of Surry Power Station

The Surry Power Station is a two unit site owned and operated by Virginia Electric and Power Company (the Company). It is located on the James River in Surry County, Virginia and is approximately twelve miles Northwest of Newport News, Virginia. Each unit is a three-loop pressurized water reactor rated at 2441 MW thermal and 775 MW net electrical. The nuclear steam supply systems and main turbine generators were supplied by the Westinghouse Electric Corporation. The Stone and Webster Engineering Corporation acted as the architect engineer.

Unit 1 achieved commercial operation in December 1972 and Unit 2 in May 1973. To date, Unit 1 has operated for approximately 76,000 hours and Unit 2 for approximately 76,600 hours.

B. Brief Overview of the Incident

On December 9, 1986, Unit 2 was operating at 100% power. At approximately 1421, the unit tripped due to a low-low steam generator level protection signal. Shortly after the reactor trip, the 18 inch suction line to the 'A' Main Feed Pump failed catastrophically. The failure was in a 90 degree elbow approximately one foot downstream of a tee from a 24 inch header and resulted in complete separation and dislocation of the suction line.

The heated, pressurized water in the system flashed to steam as it was discharged from the severed pipe into the Turbine Building, engulfing personnel and equipment in the area. Eight individuals in the immediate area were burned by the steam, six seriously. The injuries to four of these individuals subsequently proved fatal.

Following the rupture of the suction line, the Surry Power Station Emergency Plan was implemented and a "Notification of Unusual Event" was declared, followed by an upgrade to the "Alert" classification.

Secondary systems were secured and isolated to terminate the discharge of steam and water from the pipe rupture. The unit was stabilized by 1434 with two reactor coolant pumps running and primary system pressure and temperature being maintained by relieving steam to the atmosphere. No radioactive release resulted from the event. A cooldown was initiated and the unit was in the cold shutdown condition by 0704 the following day.

After preliminary investigation of the cause of the rupture, the decision was made to shut down Unit 1. The shutdown was initiated at 1730 on December 10, 1986 and the unit was off line at 2247.

This report will describe this event in detail, identify the cause of the failure, describe the effects of the failure, detail the recovery actions taken or to be taken, and describe the return to service plans for the units.

C. Virginia Electric and Power Company and NRC Response

Following the termination of the "Alert" classification, Virginia Electric and Power Company management immediately initiated recovery activities. An organization was established and resources identified for evaluating the incident and recommending recovery actions. In addition, the NRC Region II, in Atlanta, Georgia, notified the Company that an inspection team was being dispatched to Surry. The team was upgraded to an Augmented Inspection Team (AIT) after arrival. The AIT was designated to examine the Company's response to the incident and perform a separate investigation. The Company organization was in place and functional early the evening of December 9th. The NRC's AIT was on site and met with the Company's incident response organization at 2300 on December 9th.

The Company Incident Response Organization (Figure I-1) was divided into four groups including the Incident Coordination and Control group. Because of the eight injuries, an Industrial Safety Independent Investigation Committee was established. The third group was a Technical Independent Investigation Committee to determine the cause of the trip and pipe rupture and recommend recovery actions based on their findings. The Station and Corporate Nuclear Safety and Licensing organizations were also included to facilitate station response to the requirements of the AIT's investigation.

Incident Response Organization Chart

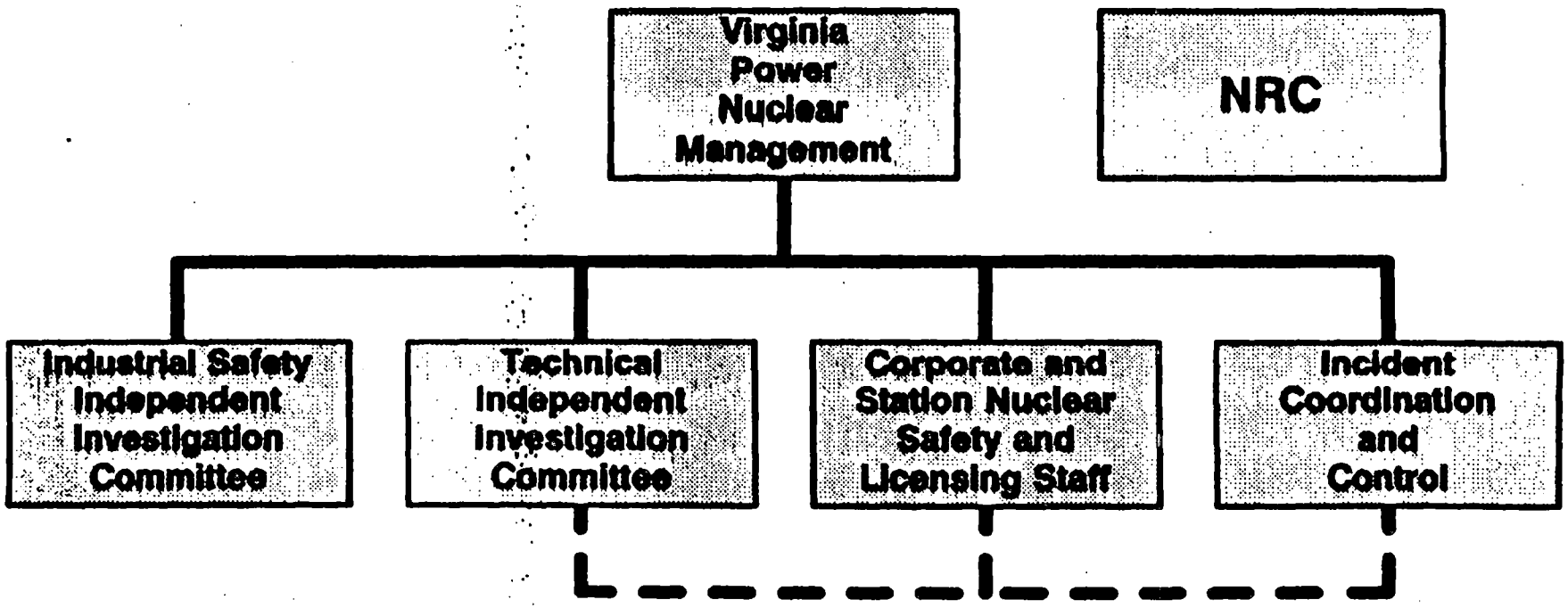


FIGURE I-1 - Virginia Power Incident Response Organization

II. Detailed Sequence of Events

A. Narrative

1. Introduction

The following narrative describes the significant operating events for the Surry Power Station Unit 2 feedline failure which occurred on December 9, 1986. Attachment II-1 to the narrative provides a more concise detailed chronological sequence of events. The narrative and sequence of events are compiled from a variety of sources including 1) the sequence of events recorder, 2) the Emergency Response Facility Computer System (ERFCS) historical file, 3) the plant Security computer system, 4) operational and emergency response logs and 5) plant personnel interviews.

Two items need to be considered when reviewing the sequence. First, the clocks for the various plant computer systems are not synchronized. Since the Sequence of Events (SOE) recorder, with a resolution of milliseconds, is the most detailed and accurate record of the event, information from other sources was correlated to a known event shown on both the SOE output and the other source, e.g. the Security computer system. The time delta was then applied to the SOE time scale which is the basis for this report.

The other consideration involves the use of the ERFCS historical file. The ERFCS was intended as a system to display key safety parameters in an easily understandable format in near real time during an event. The ERFCS historical file provides a snapshot of

its data base on a 15 second frequency for a period of time before and after the initiating sequence. The data base is constructed of digital points, analog points, and calculated digital and analog points, all of which are sampled asynchronously at different frequencies. Consequently, the sequencing resolution of the system is no greater than 15 seconds and the information obtained must be used with caution when diagnosing events occurring over a time scale of seconds rather than minutes. It does serve a very useful historical function in providing a global picture of the event and confirming other more detailed information from the SOE recorder and other sources.

2. Conditions Prior To The Reactor Trip

Surry Unit 2 was operating at 100% power after having been returned to service from a refueling outage on December 2, 1986. The unit had been in a stable mode of operation since 1120 hours on December 8, 1986. Unit 1 was operating at 100% power and was in a stable condition.

Attachment II-1 lists the specific plant conditions at the time of the event. The condensate system was in normal operation with A (2-CN-P-1A) and B (2-CN-P-1B) condensate pumps, A (2-SD-P-2A) and B (2-SD-P-2B) LP heater drain pumps and the B (2-SD-P-1B) HP heater drain pump running. The full flow condensate polishing system and all feedwater heater trains were in service.

Work activities in progress included the testing of Unit 2 relays in the protection circuitry. Earlier in the day, Instrument Technicians determined that the Reactor Coolant Pump (RCP) underfrequency "B" train test relay would not actuate while performing Periodic Test (PT) 2.36. A Station Deviation and a Work Request were written. "B" reactor trip bypass breaker was closed in accordance with PT 8.1 at approximately 1325 in preparation for performing the work on the RCP underfrequency relays (RT1-YB and RT7-YB). No work on the relays was in progress at the time Unit 2 tripped.

In addition, maintenance work was being completed on the new Atlas-COPCO (Grey) air compressor. Prior to starting the Grey compressor, station air was being supplied by the older Atlas COPCO (Blue) compressor and the Condensate Polishing Building air compressor, which was supplying 150 CFM to the Turbine Building station air. Instrument air was being maintained above 100 psi according to Control Room indication.

In order to test the Grey compressor, the Blue compressor was stopped and a start of the Grey compressor was attempted. One power supply (breaker) supplies both compressors. When the 480V bus main breaker tripped, the Unit 1 operator was notified. The operator checked instrument air pressure (approx. 85 psi) and called the Condensate Polishing Building for an increase in instrument air flow. The flow was increased to 250 CFM; however, instrument air continued to slowly decrease and was noted to be

about 78 psi just after the Unit 2 trip. Prior to this trip, an air pressure of 78 psi had had no effect on plant operation. A review of past operating experience confirmed that plant performance is not normally degraded with 78 psi of instrument air.

At the time of the event, the operating shift was manned by five Senior Reactor Operators (SROs) and three Reactor Operators (ROs). This manning was well in excess of the 2 SROs and 3 ROs required by Technical Specifications because 2 SROs from the Training Department were obtaining their quarterly on shift time. In addition, a SRO was performing an operator evaluation as a Check Operator. The Shift Technical Advisor (STA) was on duty in the Technical Support Center (TSC) which is adjacent to the main Control Room.

The Assistant Station Manager for Nuclear Safety and Licensing and the Superintendents of Operations, Technical Services, and Maintenance were at the station. The Station Manager was returning from a trip to the Corporate offices in Richmond and was in the Security entrance at the time of the event.

3. Sequence of Events/Operator Actions

The initiating event was the closing of C Main Steam Trip Valve (MSTV TV-MS-201C). The main steam line trip valve is a reverse seated check valve. Its purpose is to close immediately in the event of a rupture in the main steam line between the valve and the turbine, thus preventing flashing and rapid blowdown of the shell side of the steam generator. During normal operation, the

valve disc is held open above the steam flow path by compressed air. A closure signal vents the compressed air to the atmosphere and compressed coil springs initiate valve closure as the trip valve disc drops into the steam flow path. The valve closes rapidly due to spring force and the force of the steam flow against the disc.

With the closure of the C MSTV, the steam flow from the A (2-RC-E-1A) and B (2-RC-E-1B) steam generators (S/G) increased in response to the 100% full load turbine demand.

Closure of C MSTV was not observed in the Control Room. The Emergency Response Facility Computer System (ERFCS) did not identify the MSTV closure because the "valve closed" limit switch contact did not actuate. Post trip investigation has confirmed that the MSTV rocker arm linkage was slightly out of adjustment. This limited the downward stroke of the actuating cylinder piston causing it to contact the lower (valve closed) limit switch arm but not to actuate it in all cases. The post trip investigation found the lower limit switch within approximately 1/32 inch of its actuation point. In addition, testing confirmed that the annunciator in the Control Room alarms on intermediate MSTV indication but was apparently not observed because of the multitude of annunciations and alarms received almost simultaneously.

The short term rapid increase in A and B steam flow resulted in a feedwater flow - steam flow mismatch signal because the steam flow

responded more rapidly than the feedwater flow which is controlled through the feedwater regulating valve control system. The mismatch signal occurred approximately 4 seconds before the trip and is shown on the Sequence of Events (SOE) output at 1419:59. An increase in A and B steam flow is also shown on the Control Room steam/feed flow strip charts.

Subsequent to the mismatch signal, level error signals were received on the SOE recorder at 1420:01 for steam generator C (2-RC-E-1C) and immediately thereafter for B. A level error signal was received on A at 1420:03. For steam generator C, the level error signal was due to a low level resulting from a pressurization of the steam generator and a subsequent shrink in level. For steam generators A and B, the level error signal was due to a high level resulting from reduced pressure in the steam generators and a subsequent swell in level.

Closure of C MSTV and the increase in steam flow from S/G A and B pulled the A (TV-MS-201A) and B (TV-MS-201B) MSTVs closed as has happened in the past and stopped all steam flow to the HP turbine. The closing of the A and B MSTVs was caused by a venturi effect. When the steam flow exceeds the 100% value, the venturi effect overcomes the air pressure holding the valve out of the steam flow and closes the MSTV.

As the initial set of alarms came in on the Control Room vertical board H panel, the C S/G reached its low-low level setpoint at

1420:03 and a reactor trip was generated on steam generator low-low level within milliseconds. The turbine was automatically tripped on the reactor trip and a series of normal post trip alarms, (e.g. average temperature and reference temperature deviation, RPI rod bottom stop and turbine runback), were received.

The Unit 2 RO initiated the immediate actions of Emergency Procedure (EP) 1.00, "Reactor Trip/Safety Injection", while one of the SROs obtained a copy of the procedure. Within seconds a SRO announced the Unit 2 trip on the plant public address system (Gaitronics) and called the STA to the Control Room. A manual reactor trip and a manual turbine trip were performed at 1420:06 and at 1420:08 respectively in accordance with EP-1.00.

The plant responded as designed following the initiating event. Since the S/G Power Operated Relief Valves (PORVs) were in manual, the steam generator safety valves lifted shortly after the MSTVs closed at approximately 1085 psi on the S/G secondary side. With the reactor trip, core power rapidly reduced to the decay heat levels. Shortly after the reactor trip, it was noted that Control Bank B rod cluster control assembly (RCCA) M-10 did not indicate that it was fully inserted but was indicating approximately 30 steps withdrawn.

As designed, auxiliary feedwater (AFW) flow from two motor driven pumps (2-FW-P-3A and 2-FW-P-3B) was automatically initiated on low-low level in C steam generator at 1420:03. PCV-MS-202A and B opened as a result of low-low level in 2 of 3 steam generators at

1420:09 and admitted steam to the steam driven AFW pump (2-FW-P-2).

Following Unit 2 turbine trip, the S/G safeties acted as designed, as a heat removal path, because the normal heat removal path, the condenser bypass or steam dump valves, was not available after the MSTVs closed. The reactor coolant system (RCS) temperature, pressurizer pressure and pressurizer level were reduced as a result of the heat removal from the secondary side. When primary temperature reached 554° F in combination with the reactor trip, the feedwater regulating valves closed automatically as designed (approximately 1420:26, based on the ERFCS output). At 1420:35, the main generator output breakers opened and station service transferred over to reserve station service as shown by the alarms on the SOE. This is a normal occurrence on a reactor trip. According to operator interviews, a small steam noise started at approximately the time of transfer; it continued for 3 to 4 seconds and was followed by a loud rushing sound.

After the announcement of the Unit 2 trip, the STA immediately left his desk in the Technical Support Center (TSC) and proceeded down the hallway connecting the Unit 1 and Unit 2 sections of the Turbine Building. Upon entering the Control Room, the STA initiated his review of the Critical Safety Function (CSF) status trees. Two ROs were in the Control Room Annex and entered the Control Room upon hearing the trip announcement. Two operators were in the process of entering the Unit 2 Cable Tray Room doorway

(El. 45 ft.) in the area above the Unit 2 main feed pumps at the time of the rupture of the A (2-FW-P-1A) main feed pump suction piping. The Security computer recorded their entrance and an intrusion alarm on the cable tray room door which is believed to be caused by the shock of the pipe rupture. Based on a correlation of the card reader entry times from the Security computer system printout and the operator interviews to the SOE printout, it is estimated that the pipe rupture occurred at 1420:43 approximately 35 to 40 seconds after the unit trip.

As the A main feed pump suction and condensate header discharge pressure dropped, the ERFCS shows that the third condensate pump (2-CN-P-1C) started on low discharge pressure. The A main feed pump tripped at 1421:01 and the B (2-FW-P-1B) main feed pump tripped at 1421:24 based on the SOE output.

The ROs were initially unaware of the A main feed pump trip because pump breaker to control switch disagreement (amber light) was not observed. Instead, the green light was lit indicating that the control switch had probably been turned to "off" manually. This discrepancy has not been fully resolved, but can be understood if an operator switched it to the off position at approximately the same time the pump motors tripped.

A SRO who had left the Control Room Annex and proceeded to the northwest corner of the Unit 2 Turbine Building mezzanine (El. 27 ft.) was standing by the elevator when he heard the loud explo-

sion and was engulfed by steam. He proceeded back into the Control Room Annex and informed the operating shift that they had a major problem in the Unit 2 Turbine Building with a significant water or steam release underway. He also told them that there were injured people but that he did not know how many. A Gaitronics announcement was made and the First Aid Team was told to proceed to the Unit 2 Turbine Building.

The Shift Supervisor directed the Unit 2 RO to turn off the main pumps in the Condensate/Feedwater train. When the RO went to stop the main feedwater pumps, he noted that the A pump was already off (no disagreement light) and the B pump tripped (disagreement light) as he moved his hand to the handle on the control board. He also noted that the LP heater drain pumps had already tripped. Based on the ERFCS output, the condensate pumps (and the HP heater drain pump) were tripped at approximately two minutes after the reactor trip and the forced flow of water from the break was stopped.

Approximately three minutes after the unit trip, the initial emergency response had been taken and the situation was stable. The primary side temperature was approximately 554° F, pressurizer level was approximately 32% and pressurizer pressure was approximately 2080 psig. The STA had completed his initial review of the CSF status trees and reported to the Shift Supervisor that there were no "red paths" or safety functions requiring immediate attention. The requirements of EP-1.00 (Reactor Trip/Safety

Injection" had been completed for a reactor trip without safety injection. In addition to verifying reactor trip and turbine trip, procedures require that the RO open the turbine drains, reset the moisture separator reheaters, verify that AC buses are properly energized, verify automatic switchover to ensure that Unit 2 was being supplied by the reserve station service transformers (RSST) and determine whether safety injection (SI) had actuated. The operators completed all procedure actions for a reactor trip without SI.

With the determination that SI had not actuated and was not required, the RO transitioned to EP-1.01, "Reactor Trip Recovery." This procedure provides guidance for stabilizing and controlling the unit following a reactor trip without SI. The initial actions of EP-1.01 were initiated, which required the RO to confirm that (1) RCS average temperature was stable at or trending to 547° F, (2) main feedwater was isolated and that auxiliary FW flow was initiated, (3) all control rods were fully inserted, (4) pressurizer level and pressure were appropriate and (5) the STA had been notified. The ROs completed these actions in accordance with the procedure.

The feedline rupture had been isolated and steam generator levels were being maintained by flow from the 2 motor driven and 1 steam driven auxiliary feedwater pumps. The third licensed RO was controlling steam generator pressure and RCS temperature using manual control of the C (2-RV-MS-101C) steam generator power operated relief valve (PORV). The STA continued to monitor the CSF status trees to insure that all safety functions continued toward a "green path" or satisfactory condition.

The known problems included: 1) RCCA M-10 was not indicating as fully inserted, 2) an unknown number of injured personnel required assistance, 3) the security card readers were beginning to malfunction, and 4) the "C" MSTV was indicating intermediate position.

Plant management had begun to arrive in the TSC to assess the situation. The Assistant Station Manager - Nuclear Safety & Licensing had arrived after quickly surveying the steam filled Unit 2 Turbine Building basement and determining that personnel had been injured. The Station Manager and the Superintendent of Operations were in the Control Room. Emergency Plan Implementing Procedures were obtained and were initiated. The plant status was being reviewed using the Emergency Response Facility Computer System in the TSC. After discussions with the Control Room, it was determined that the 18 inch suction line to the "A" main feedwater pump had ruptured.

As the steam cleared from the Unit 2 Turbine Building, additional people made their way to the Control Room. The NRC Resident Inspector entered the Control Room approximately two minutes after the trip. The Station Manager proceeded to discuss the event and the status of the Emergency Plan activities with the Shift Supervisor who was the acting Site Emergency Manager (SEM).

Plant conditions remained stable with RCS temperature continuing to trend down to approximately 545° F. At 1425:33 the R

(2-RC-P-1B) RCP was turned off to further reduce the heat input to the RCS.

Additional equipment problems were noted approximately five minutes after the trip. The release of hot water which flashed to steam had caused 62 of the Unit 2 fire protection sprinkler heads to actuate providing an additional source of water to the large amount already released from the break. The Cardox control system was electrically shorted and actuated, releasing CO_2 in the Unit 1 and Unit 2 Cable Tray rooms. In a similar manner, Halon was actuated and released into the Unit 1 and Unit 2 Emergency Switchgear rooms. Water from a nearby sprinkler head ran under the door into the Unit 2 cable spreading room. As the water seeped through electrical penetrations, it was noticed dripping behind the Unit 2 main control board. In addition, several normal lighting circuits in the Turbine Building were shorted.

The operating shift became aware of the Halon problem by alarm annunciation in the Control Room and observation of a portion of the area on Control Room TV monitor. In addition, operators dispatched from the Control Room were reporting the problem. Construction and plant personnel exited from the Emergency Switchgear Room and the area was checked to ensure that the room was clear of people.

The Shift Supervisor declared an emergency of the lowest classification, Notification of Unusual Event, at 1430. The

Nightingale Air Ambulance and the Surry and Isle of Wight Rescue Squad ambulances were called for transportation of injured personnel.

Shortly after the Notification of Unusual Event was declared, the NRC Operations Center called the Control Room based on their earlier informal notification of the event by the NRC Resident Inspector. The NRC Operations Center was informed of the situation as known at the time and continuous phone communications were established for the remainder of the event.

After assessing the situation in the control room, the Station Manager relieved the Shift Supervisor as the Station Emergency Manager. With the continued addition of auxiliary feedwater, steam generator levels increased. At 1428:34, the B S/G low-low level alarm cleared and at 1430:14, the C S/G low-low level alarm cleared. Since the required 2/3 logic was no longer in effect, the steam driven auxiliary feedwater pump shut down as designed. The motor driven auxiliary feedwater pumps continued to provide adequate flow to increase steam generator levels.

Reactor coolant makeup was manually shifted from the volume control tank (VCT) to the refueling water storage tank (RWST) in order to increase the rate of boration so that the necessary shutdown margin could be established prior to plant cooldown. The STA initiated the shutdown margin calculations.

Plant conditions were stable with the RCS temperature being maintained at approximately 540° F with C S/G PORV.

The First Aid team had established a triage area for six of the injured personnel outside of the Unit 2 Turbine Building track bay on the grassy area near the reserve station service transformers. The two people with the lesser injuries (F. P. Newby and A. D. Blades) were escorted through the station rear entrance for treatment at the Engineering and Construction First Aid Station. A. D. Blades was treated and released while F. P. Newby was transported by private vehicle to the Smithfield Medical Clinic. Two other people left the Unit 2 Turbine Building by the stairs in the northeast corner and were treated in the Maintenance Services offices.

Immediate first aid consisted of a complete patient survey on each injured person. Oxygen was administered and their clothing was cut away and shoes were removed. Their burns were cooled with a saline/water solution. After applying dressings, burn sheets, and blankets, the injured personnel were placed on backboards in preparation for transportation to the Training Center. The SEM dispatched several teams from the Control Room to search the Unit 2 Turbine Building and spaces where CO_2 and Halon had initiated to insure that all injured personnel were identified and attended to.

In the TSC, the administrative staff had completed the administrative work required to man the TSC. Emergency Response

personnel were arriving and were initiating their respective Emergency Plan Implementing Procedures (EPIP). The Assistant Station Manager-Nuclear Safety and Licensing had assumed control of the staff in the TSC. He was reviewing the Emergency Action Level (EAL) table and discussing the advantages of upgrading the emergency to a higher classification.

At 1440, the SEM declared an Alert. While the EAL did not require an upgrade, the Alert was declared in order to obtain personnel accountability and to formally organize the response effort in accordance with the emergency plan.

Damage assessment was continued as maintenance, electrical and operational teams were dispatched throughout the plant to report on the extent of damage. Emergency response personnel were directed to report to their assigned areas.

The search and rescue teams had not located any additional injured personnel. The injured personnel were surveyed for radioactive contamination and upon confirmation that no personnel were contaminated they were transported by Surry Power Station ambulance and company vehicles to the Training Center.

The plant conditions remained stable with RCS temperatures at approximately 545° F and heat removal being provided by the C S/G PORV. At 1444, based on the SOE recorder output, the A RCP was secured in order to further reduce the heat input to the RCS.

The Assistant Shift Supervisor completed his notification to the State and local authorities that an event had been declared at 1430. The notification was classified as a Notification of Unusual Event. It was reported that rescue units from Nightingale and Medflight had been requested. Authorities were informed that no additional emergency response was planned, that on-site personnel were not being evacuated, that the situation was stable and that a release of radioactive materials was not underway or projected. The event was characterized as a feedline break in the Unit 2 Turbine Building. The state and six local authorities all acknowledged receipt of the notification.

In the TSC, the support staff was assessing unit conditions, providing additional information to the Corporate offices, and helping to coordinate the medical response aspect of the emergency.

The Nightingale Air Ambulance arrived at the Training Center at approximately 1450 and picked up Timothy D. Smith and Ronald E. Wilkes. These men were transported to the burn trauma unit of Norfolk General Hospital. The other injured personnel remained at the Training Center pending arrival of the Medflight air ambulance and ambulances from the Isle of Wight and Surry Rescue Squads.

With the plant in stable conditions, the SEM relocated to the TSC at 1452 in order to consolidate the emergency response effort and to take advantage of the communications links in the TSC. The TSC

was activated at 1457 and the SEM provided an update of the emergency situation to the response team members. Upon activation, the Emergency Procedures Coordinator and the Technical, Maintenance, and Radiological Emergency Response Directors or their alternates were in the TSC.

The SEM held a brief response team meeting to review ongoing activities and make additional assignments. In particular, the acting Radiological Director was directed to dispatch the radiological assessment teams to implement the dose assessment and in plant monitoring emergency procedures to confirm that no radiological release was in progress based on the installed plant radiation monitoring instrumentation. The results from this assessment confirmed that no release was in progress. In addition, the SEM directed that preparations be made for a personnel accountability.

At 1500, the Control Room communicator formally notified the NRC Operations Center that the emergency had been upgraded to an Alert classification. The Unit 2 event was described as a loss of feedwater resulting from the rupture of the A main feed pump suction piping. The NRC was informed that Unit 1 was not affected by the event and remained at 100% power. Unit 2 had been at 100% power prior to the event, safety injection had not occurred, the unit was currently at zero power and being cooled by forced circulation. It was noted that radiation levels in the plant were not increased and that radioactive material was not released. The

NRC was also informed that personnel were injured, that Rescue Squad assistance had been requested and that company emergency personnel and facilities had been activated. The report closed by stating that state and local authorities had been notified.

With the upgrade to an Alert, Security personnel were dispatched at 1502 to the Local Emergency Operation Facility (LEOF) which is located in the Surry Training Center to prepare that facility for activation.

During this time period, unit conditions remained stable. RCS temperature was approximately 530° F and decreasing, pressurizer level was approximately 25% and pressurizer pressure was approximately 2160 psig.

At 1506, the B motor driven auxiliary feedwater pump was secured because all steam generator levels had returned to normal. The A motor driven AFW pump remained in service to provide make up to the steam generators during cooldown. In addition, a manual emergency boration was begun at 1514 in preparation for eventually proceeding to cold shutdown. The starting boron concentration was 1170 ppm.

Preparations for the personnel accountability had been completed and accountability was initiated at 1518. The announcement, which was made from the TSC over the plant Gaitronics, directed all plant personnel not responding to the emergency to report to their

assembly areas. Plant personnel proceeded to their assigned locations.

The Emergency Communicator completed notification to the State and local authorities of the upgrade of the event to an Alert Classification. It was noted that assistance in the form of ambulances from Isle of Wight and Surry Rescue Squads had been requested. The authorities were notified that the transportation off-site of six injured personnel was in progress, that on-site personnel were not being evacuated, that the situation was stable and that a release of radioactive materials was not underway or projected. The event was characterized as a main feed piping rupture, and it was noted that the Alert status would be maintained until accountability was obtained.

The situation with the injured personnel continued to be of prime concern. At 1534, the Medflight air ambulance arrived at the Training Center. Clyde W. Matthews was placed aboard the helicopter and was airlifted to Norfolk General Hospital. At approximately the same time, two individuals, L. E. Wisecarver and Lewis E. Stevenson, were transported by Isle of Wight Rescue Squad ambulance to Riverside Hospital in Newport News. They were later transferred by the Nightingale helicopter to Norfolk General. D. Browning was transported by Surry Rescue Squad ambulance to Riverside Hospital.

The Corporate Emergency Response Center (CERC) in Richmond was activated at 1535. While the LEOF was not formally activated, it was manned at 1557.

The manual emergency boration which was underway was stopped at 1539 and a chemistry sample was requested. At 1600, Chemistry reported that the boron concentration was 1588 ppm. The unit operational status remained in a stable condition as earlier with RCS temperature at approximately 520° F and decay heat removal through C S/G PORV.

The personnel accountability was completed at 1548 and the results were reported to the SEM in the TSC. All station personnel were accounted for except for three people. Two people, a badged contract employee and his visitor, were located in the TSC where they had been supporting the response effort. The remaining person, a truck driver, was accounted for at 1557 when he was located in the Mechanical Shop.

Upon completion of the personnel accountability, the transportation of the injured personnel to medical facilities, and the organization of the response personnel into their response teams, the reasons for declaring an Alert were resolved. The SEM reviewed the situation in a meeting with his Emergency Response Directors and obtained reports on the status of activities in their respective areas. Based on the situation, the SEM decided to terminate the Alert. This decision was reviewed with the

Recovery Manager who had arrived at the TSC and the NRC Resident Inspector. With complete agreement the SEM terminated the Alert at 1625 and plant personnel were notified by an announcement over the Gaitronics. The Chairman of the Station Nuclear Safety and Operating Committee scheduled a meeting for all primary and alternate members for 1700.

Notification of the State and local authorities and NRC was initiated by the Emergency Communicator at 1624. The authorities were told that the Alert was terminated at 1623, that the unit conditions were stable and that the intention was to proceed to cold shutdown for repairs. The state and six local authorities acknowledged receipt of the notification.

At the time of the Alert termination, Unit 2 conditions remained stable with decay heat being removed by C S/G PORV. It was noted that RCCA M-10 was now indicating fully inserted by the Rod Position Indicators.

A Station Nuclear Safety and Operating Committee (SNSOC) meeting was convened at 1700. The committee discussed the necessary precautions for continued operation of Unit 1 and reviewed the actions required for cooldown of Unit 2. A key concern was the loss of the Cardox system and isolation of the Unit 2 Turbine Building sprinkler system. It was decided that the temporary firewatches already established immediately after the event by Operations personnel should be continued on a permanent basis.

The Cardox was ordered and scheduled for a morning delivery on the following day.

Early assessments had shown that there was no radiological release. In order to further substantiate that fact in preparation for resuming cooldown of Unit 2 to a cold shutdown condition, the following steps were taken. Blowdown samples on all three steam generators from the previous day were evaluated. An operator was to trend the main steam radiation monitors locally at the radiation monitor panel in the Emergency Switchgear Room. In addition, the radiation monitors were to be trended on the ERFCS. Local samples were to be taken for radiological analysis from a Main Steam drain line. Samples were scheduled to be taken every 15 minutes initially, then hourly thereafter until terminated.

The need to de-energize potential problem circuits in the Unit 2 Turbine Building basement for personal safety was reviewed. The electricians had already meggered the Unit 2 circulating water motor operated valves (MOVs) and found them to be satisfactory. It was decided to de-energize motor control centers 2A1-2 and 2B1-3 due to grounds.

The plans for cooldown of Unit 2 were discussed. It was agreed that a normal cooldown of the RCS at approximately 50° F per hour using the C S/G PORV and the A motor driven auxiliary feedwater pump was appropriate as long as the proposed radiological assessments continued to indicate that no detectable radioactivity

was found by the proposed sampling programs. In preparation for the cooldown, the residual heat removal (RHR) system was to be heated up. From a manning standpoint, it was agreed that the operating shift at the time of the accident should stay on until 2000 to supplement the shift that had come on at 1600. In addition, the shift which was scheduled to arrive at midnight had been told to report at 2000.

Concerning the continued operation of Unit 1, Control Room habitability was reviewed (See Section VIII-b). It was reported that the area was now clear, and it was decided that the control room doors should be closed.

The fire detection and suppression system was reviewed, and temporary firewatches were to be continued on a permanent basis in all affected areas until all systems were returned to normal.

Pending investigation of the cause of the Unit 2 piping failure, it was decided to rope off the feed pump area in the Unit 1 Turbine Building basement to prevent personnel entry.

The SNSOC meeting was concluded at approximately 1745 and members returned to their areas to implement the required actions.

Unit 2 cooldown was initiated at 1821. The Recovery Manager met with his staff to plan the investigation and to discuss whether a shutdown of Unit 1 was warranted. A six man NRC Inspection team

arrived on site at approximately 2130 and was given a briefing and short walkdown of the Unit 2 feed pump area.

At 2300, a meeting was held between the Recovery Manager and his staff and the NRC inspection team. A summary of the event and a preliminary sequence of events was discussed. The meeting concluded at approximately midnight on December 9, 1986 and a meeting for 0900 that following morning was tentatively scheduled.

The Unit 2 cooldown proceeded as planned. The unit reached 350° F and 450 psi at 0013 on December 10, 1986 and was placed on RHR at 0355. The unit was in cold shutdown at 0704 on December 10, 1986.

ATTACHMENT II-1

SUMMARY OF SIGNIFICANT OPERATING EVENTS

EVENT: **Low-Low Steam Generator Level Reactor Trip**
UNIT NO: **2**
DATE: **12/9/86**
TIME: **1420**

INITIAL CONDITIONS OF UNIT 2 ON DECEMBER 9, 1986

Unit No. 2 was stable at 100% power. The unit had returned to power from a refueling outage on 12/2/86 and had been in a stable mode of operation at 100% power since 1120 hours on 12/8/86.

Plant Conditions included:

1) #2 flash evaporator was out of service.
2) Feedwater heater 3A (2-FW-E-3A) relief valve was leaking.
3) "B" reactor trip bypass breaker was closed to enable work on RCP underfrequency relays.
4) S/G PORVs were in manual.
5) The "blue" air compressor was turned off for a test run of the "grey" air compressor which had just completed maintenance. When the "grey" compressor start was attempted, the main breaker tripped. This was reported to the Unit 1 operator, and the condensate polishing building was called and asked to increase the flow. The minimum air pressure was approximately 78 psi.
6) Unit 2 charging pump (2-CH-P-1B) was out of service.
7) "A" Reactor Vessel Level Indicating System (RVLIS) upper range was out of service.
8) Emergency service water pump (1-SW-P-1A) was operable but in the alert range.
9) At the time of the event, the operating shift was manned by five Senior Reactor Operators and three Reactor Operators. Their assigned functions were as follows:

Summary of Significant Operating Events (Continued)

Shift Supervisor/Unit 2 Supervisor - SRO
Unit 1 Supervisor - SRO
Check Operator SRO
Extra On-Shift Supervisor - SRO
Extra On-Shift Supervisor - SRO
Unit 1 Operator - RO
Unit 2 Operator - RO
Miscellaneous Panel/Third License - RO

SEQUENCE OF EVENTS/OPERATOR ACTIONS

C main steam trip valve closed. Control Room annunciator was not observed.

1419:59 FF < SF S/G B and FF < SF S/G A alarms

A & B steam flows increased to try to maintain full load. No alarms received on C S/G.

1420:01 S/G level error alarms received on C steam generator. S/G level error alarms were received on B and A immediately thereafter (Presume lo level on C and hi level on A & B). As steam flow is increased, A & B main steam trip valves are dragged closed.

Unit 2 RO identifies alarms but does not acknowledge.

1420:03 S/G C lo-lo level alarm followed by S/G lo lo level reactor trip. Turbine trip on reactor trip.

1420:03+ The Unit 2 reactor trip is announced on the Gaitronics and the STA is called to the Control Room. The STA initiates his review of the critical Safety Function status trees.

Summary of Significant Operating Events (Continued)

Unit 2 RO initiates initial actions of EP-1.00 while one of the on-shift SROs obtains copy of the procedure. Manual reactor trip and turbine trip performed to backup automatic actions as per procedure.

1420:03+ One or more main steam safety valves lift. Two motor driven and one steam driven auxiliary feedwater pumps automatically initiate as as designed.

Rod M-10 was not indicating fully inserted (approximately 30 steps).

Intermediate indication on C MSTV was noted but C steam flow was zero.

1420:26+ Main feed regulating valves close as Tave decreased below the setpoint (554° F).

1420:35 Main generator output breaker opens following 30 sec. time delay. Station service transfers over to reserve station service.

1420:43 A FW suction pipe ruptures in Unit 2 Turbine Building. (Based on interviews and Security computer output.)

1421:01 A FW pump trips. No disagreement light observed. Operators unaware of FW pump trip initially.

1421:01+ An Operations SRO returns from the Turbine Building and informs shift that there is a major problem in Unit 2 Turbine Building with a significant water/steam release underway and that personnel were injured. The first aid team was called.

1421:24 B MFP trips automatically. Disagreement light indicated.

1421:24+ Shift Supervisor directs Unit 2 RO to trip all main feed pumps, condensate pumps, high pressure drain pump, and low pressure drain pumps. Reactor operator noted both main feed pumps and LP heater drain pumps already stopped.

Primary plant stabilizing with normal pressurizer level, pressure, and Tave. Steam generator levels were maintained using auxiliary feedwater from two motor driven pumps and one steam driven pump.

1421:24+ Actions of EP-1.00 (Reactor Trip/Safety Injection) are completed. Third license RO controlling steam generator pressure and RCS temperature using manual control of C steam generator PORV.

The initial actions of EP-1.01 were initiated.

Control Room door manually opened bypassing computer controlled key-card access due to malfunctioning card reader. A Security Officer was stationed at the door and it remained open throughout the remainder of the event. The Control Room Annex door was opened to allow easier access. The STA had completed his initial review of the CSF status tree and informed the Shift Supervisor that no functions required immediate attention (no red path).

1422:53 NRC Resident was aware of the event and in the Control Room.

1425 Stopped B RCP in order to reduce the heat input to the RCS. Plant conditions were stable.

1425+ Heat from break actuated fire protection sprinkler systems. Water shorted out the station Halon and Cardox control systems actuating CO_2 in the Unit 1 and Unit 2 Cable Tray rooms. Halon was actuated in the Unit 1 and Unit 2 Emergency Switchgear rooms.

Control Room operators identified that emergency switchgear Halon system actuated from noise and visual observation on TV monitor covering portion of area. They were not aware that CO_2 had also been initiated in the cable spreading area above the Control Room.

Summary of Significant Operating Events (Continued)

Some normal lighting circuits in the Turbine Building were lost as they were shorted out.

1430 Notification of Unusual Event was declared by the Station Emergency Manager/Shift Supervisor. Surry and Isle of Wight rescue squads were called and Nightingale medical air ambulance was called to transport the injured to the hospital.

1430+ The NRC Operations Center called the Control Room as a result of a call by the NRC Resident and were informed of the situation as known at the time. Continued communication with the Operations Center was maintained.

Station Manager relieved shift supervisor as Station Emergency Manager in the Control Room.

Steam driven AFW pump shut down as designed when S/G levels recovered and were being maintained by the motor driven AFW pumps.

Search through spaces where CO_2 and Halon initiated were begun to determine if anyone was trapped in the spaces.

Reactor coolant makeup manually shifted from volume control tank to RWST in order to increase rate of boration so that necessary shutdown margin could be established prior to plant cooldown. The STA initiated the shutdown margin calculations.

First aid team had established a triage for injured personnel and were beginning to treat injuries. RCS temperature was being maintained at approximately 540° F with C SG PORV.

1440 An Alert was declared although a review of the Emergency Action Level table did not require an upgrade of the emergency class. The Alert was declared in order to obtain personnel accountability and to organize in accordance with the emergency plan.

Summary of Significant Operating Events (Continued)

1440+ Search and rescue missions were continued to insure that all of the injured were identified. Injured personnel were surveyed for radioactive contamination and moved to the Training Center.

1440+ Damage assessment was continued as maintenance, electrical, and operational teams were dispatched throughout the plant to report on the extent of damage.

1444 Secured A RCP in order to further reduce the heat input to the RCS.

1447 Notification to State and local authorities that a Notification of Unusual Event had been declared was completed.

1450 Nightingale air ambulance arrived at training center and picked up two injured personnel. An additional air ambulance was requested from Medflight to handle one injured person.

1457 The Station Emergency Manager (Station Manager) relocated to the Technical Support Center (TSC) and declared it activated. The Radiological assessment teams implemented the appropriate dose assessment and in plant monitoring emergency procedures to determine that no radiological release was in progress based on installed plant radiation monitoring instrumentation. It was confirmed that no release was in progress.

1500 The Control Room communicator provided the formal report of the emergency Alert classification to the NRC Operations Center.

1502 Security prepared the Local Emergency Operation Facility for activation.

1506 B motor driven AFW pump was secured because steam generator levels were being adequately maintained.

1514 An emergency boration was initiated in preparation for proceeding to cold shutdown.

Summary of Significant Operating Events (Continued)

1518 Personnel accountability was initiated with the announcement for all personnel that were not responding to the emergency to report to their assembly areas.

1526 A boron concentration of 1170 ppm was reported by Chemistry.

1532 State and local authority notification of the upgrade to an Alert was completed.

1534 The Medflight air ambulance arrived and picked up one injured person.

1535 Corporate Emergency Response Center (CERC) in Richmond was activated.

1539 Manual emergency boration was secured and a chemistry sample was requested.

1548 Personnel accountability was completed.

1600 A boron concentration of 1588 ppm was reported by Chemistry.

1623 The Alert was terminated. State, local and NRC notifications were made.

Plant conditions were stable with decay heat being removed by C SG PORV. It was noticed that control rod M-10 was now indicating fully inserted.

1623+ Preparations for cooldown of the Unit were commenced.

1700 A Station Nuclear Safety and Operating Committee meeting was held. The committee reviewed the necessary precautions for continued operation of Unit 1 and the actions required for cooldown of Unit 2.

LONG TERM OPERATOR ACTIONS

1745+ Permanent firewatches established due to loss of Cardox and isolation of Unit 2 Turbine Building sprinkler system. Additional Cardox ordered and scheduled for delivery.

Summary of Significant Operating Events (Continued)

1745+ Evaluated prior blowdown samples taken on all three steam generators the day before. All were less than minimum detectable radioactivity.

Initiated trend of main steam radiation monitors. This trend was performed by an operator locally at the radiation monitor panel in the emergency switchgear room and by placing the radiation monitors on trend on the ERF/SPDS computer.

Local samples were taken for radiological analysis every 15 minutes initially, then hourly thereafter on C S/G from a main steam drain line. No detectable activity was found.

Borated primary to cold shutdown boron concentration. Pulled shutdown banks. Commenced normal 50° F/hr. cooldown using C S/G PORV and A motor driven auxiliary feedwater pump.

Electricians meggered Circulating Water MOVs in Unit 2 Turbine Building and found them to be satisfactory. De-energized Turbine Building motor control centers 2A1-2 and 2B1-3 due to grounds.

Roped off and posted a security officer in Unit 2 basement to preserve the area for investigations.

Roped off feed pump area in Unit 1 Turbine Building.

1821 Initiated Unit 2 cooldown.

2130 NRC inspection team arrived on site and was given a walkdown of the area and requested the area be quarantined for their inspection.

2300 Recovery Manager and his staff provided NRC inspection team with a summary of the event and a preliminary sequence of events.

Summary of Significant Operating Events (Continued)

December 10, 1986

0013 Unit 2 reached 350° F and 450 psi.

0355 Unit 2 was placed on Residual Heat Removal System.

0704 The unit was in cold shutdown in a stable condition.

III. CONTRIBUTING FACTORS AND SYSTEM INTERACTIONS

A. Factors Which Directly Contributed to the Trip

1. Main Steam Trip Valve and Instrument Air Pressure

Surry Unit 2 tripped as designed when a "Low-Low Steam Generator Water Level" protection signal occurred on the 'C' Steam Generator Reactor Protection System Instrumentation. This occurrence was a result of the unplanned closure of the 'C' Main Steam Trip Valve (MSTV). The MSTV closure was initiated by a slight reduction in Instrument Air pressure which lead to a steam flow assisted closure. The 'C' MSTV would not be expected to close with the slight reduction in Instrument Air pressure, however, a further investigation revealed that the valve disc had not been in a fully open position. The slight reduction in Instrument Air Pressure allowed enough deflection for the steam flow to force the disc shut. The inability of the disc to achieve a fully open position was caused by a misalignment of the valve bonnet. The evaluation of the 'C' MSTV is discussed in Section X.A.2 of this report. Events preceding the trip are discussed in Section II.A of this report.

The station compressed air system had been previously identified as requiring improvements and upgrades. Two projects were underway to implement the upgrade plans at the time of the December 9, 1986 event. One project involved replacement of the station service air compressors and the other involved replacement of the Station instrument air compressors.

The existing instrument air compressors (1-IA-C-1 and 2-IA-C-1) are positive displacement, reciprocating type air compressors which were installed as original plant equipment. The on-going project will replace the two original air compressors with two oil free, rotary screw water cooled air compressors. The new Instrument Air compressors are a proven design which will improve the reliability of the Instrument Air systems and reduce maintenance requirements. The new compressors will also increase the capacity of the Instrument Air system. The service air system upgrade is also designed to improve system reliability and reduce maintenance requirements.

Construction is underway on the service air compressor replacement project, and it should be completed in the third quarter of 1987. The Instrument Air compressor replacement project is completing the conceptual engineering phase. In the interim two (2) Altas Copco Rotating Compressors are being used to supply Instrument and Service Air.

B. FACTORS WHICH DIRECTLY CONTRIBUTED TO THE PIPE FAILURE

1. Pipe Wall Thinning on 'A' Main Feed Pump Suction Line

The 18" suction line which supplies the 'A' Main Feed Pump was fabricated using ASTM A-106, Grade B, Extra Strong carbon steel seamless pipe and ASTM A-234, Grade B, Extra Strong, WPB carbon steel wrought fittings which had a nominal wall thickness of 0.50 inches ± 10% at installation.

Since installation, the bulk single-phase corrosion/erosion mechanism, as described in Section VI.B of this report, had substantially reduced the original wall thickness. Ultrasonic wall thickness measurements and micrometer measurements taken on the elbow following the failure showed a gradually sloping wall thickness loss over much of the suction line. At several locations, usually near welds, localized cavities had been formed in the elbow inner surface by the corrosion/erosion process. The remaining wall thickness at these localized areas has been measured as low as 0.048 inches while adjacent locations were 0.090 to 0.140 inches in thickness.

Using the code minimum wall equation and assuming an internal pipe pressure of 600 psig, a temperature of 370°F, and an ultimate strength of 60,000 psi results in a calculated burst thickness of 0.090 inches and a yield thickness of 0.173 inches.

2. Feed Pump Suction Pressure Transient

Based on information gathered from the Sequence of Events Recorder, the Emergency Response Computer, the Security Computer, and Control Room recorders, the following scenario best describes the pressure transient which occurred at the feed pump suction prior to the rupture of the elbow in the 'A' Main Feed Pump suction line.

Prior to the reactor trip, with the unit operating at 100% power, both Main Feed Pumps 2-FW-P-1A and 1B were operating with a suction pressure of about 367 psig (calculated value) and a discharge pressure of about 1040 psig (recorded value) as measured at the main feed discharge header. The temperature of the water was about 374°F (calculated value) and the combined flow to both feed pumps was about 24,884 gpm (calculated value). The feed pumps were being supplied by Condensate Pumps 2-CN-P-1A and 1B, Low Pressure Heater Drain Pumps 2-SD-P-2A and 2B, and High Pressure Heater Drain Pump 2-SD-P-1B.

Following the closure of the main steam trip valves, and the subsequent reactor trip, the feed pump suction and discharge pressures began a ramp increase due to the increase in pressure in the steam generators. About 20 seconds after the trip, when Tavg decreased below 554°F, the feed regulating valves received an automatic signal to shut and went shut, taking about 2 to 5 seconds to do so. Closure of these valves temporarily isolated all discharge flow paths for the main feed pumps, contributing to

a further increase in main feed pump suction and discharge pressure. The concurrent decrease in measured feed flow was sensed and initiated an automatic signal to open the feed pump recirculation valves which provided a flow path from the discharge of the main feed pumps to the condenser.

It is postulated that the rupture of the 'A' Main Feed Pump suction line elbow, which took place about 40 seconds following the trip, occurred at about the same time as, or just prior to, the opening of the recirculation valves.

The recorder trace of feed discharge header pressure (PR-FW-253) shows pressure modulating around a pressure of about 1040 psig prior to the event, then ramping up in pressure at a fairly constant rate for a period of about 30 to 60 seconds to a peak pressure of about 1285 psig, followed by a rapid decrease to about 200 psig. Review of the same pressure trace for a trip due to closure of a main steam trip valve on Unit 2 which occurred on January 14, 1984 shows a similar increase in discharge pressure except the pressure increased to a peak value which was about 470 psig above the initial value. During the pipe failure event, the peak pressure was only 245 psig above the initial value and was 165 psig less than the peak value reached following the 1984 trip.

Following the failure of the elbow, the 'A' Main Feed Pump operated for about 18 seconds and then automatically tripped on a low suction pressure, with a 15 second time delay, trip signal. The 'B' Main Feed Pump operated for about 41 seconds after the rupture and then tripped due to the same signal. During the investigation following the failure, the seat-disc assembly of the discharge check valve on the 'A' Main Feed Pump was found dislodged from the valve body, creating the possibility a reverse path through this valve could have led to increased pressure at the suction line. However, because the 'A' Main Feed Pump was running prior to and during the failure of the elbow and because the discharge pressure recorder trace shows no abnormal indications, it is felt that the condition of the check valve had no effect on the pressure in the suction line prior to the failure. However, the condition of the check valve may have contributed to pipe whip force and to the volume of water released back through the ruptured suction line.

Further evidence that feed pump suction line pressure never exceeded 600 psig is gained from the fact that the 'B' High Pressure Heater Drain Pump did not trip prior to the elbow failure. This pump receives an automatic trip signal if 2 of 2 pressure switches sense a pump discharge pressure above 600 psig. These pressure switches tap off the high pressure heater drain pump common discharge line approximately 8 feet from the point where it enters the feed pump suction header, which is approximately 9 feet downstream of the point on the header where

the 'A' Main Feed Pump suction line tees off of the header. While a portion of the circuitry was damaged as a result of the failure, the remaining portions were tested and it was shown that the pressure switches actuated within their design setpoint tolerances and that the pump breaker opened when it received the signal to do so. Given the close proximity of the pressure switch taps to the location of the failed elbow, the fact that the system is water solid, and the as-found pressure switch setpoints, it is concluded that the pressure at the failure location did not exceed 600 psig.

Walkdown inspections of feedwater and condensate piping following the event revealed no evidence of distortion in, or displacement of, any piping, hangers, instrument lines, or other components except in the immediate area of the rupture. This would indicate that these systems did not experience a water hammer or hydraulic shock event.

Based on the above, the following conclusions have been reached about the pressure transient in the feed pump suction line prior to the failure.

1.) The transient was a ramp pressure increase beginning with the closure of the main steam trip valves and ending with the elbow failure.
2.) The pressure ramp had a duration of approximately 40 seconds and had a pressure increase of about 200 psig.

3.) The peak pressure reached in the suction line was between 550 and 600 psig.

4.) The pressure transient was typical of those seen on other unit trips or normal shutdowns and was not a water hammer or hydraulic shock event.

5.) The rupture of the suction line elbow resulted from the combination of wall thinning due to bulk single-phase corrosion/erosion and normal feed pump suction pressure transient.

C. OTHER FACTORS

1. Main Feed Pump Operation

Both main feed pumps operated as designed during the course of the event. Initial interviews with operators following the event indicated that the 'A' Main Feed Pump showed "green light" indication following the reactor trip, but prior to the failure of the suction line. This would indicate that the pump had shutdown for an unknown reason without giving the breaker disagreement light indication on the control board which would normally occur with an automatic pump trip. A "green light" indication will occur if the pump control switch is placed in the stop position. Subsequent testing of the pump control circuitry, review of recorded data, and follow-up operator interviews led to the conclusion that the 'A' Main Feed Pump did not shutdown for an unknown reason, was running at the time of the suction line rupture and tripped about 18 seconds after the rupture due to low suction pressure. The low suction pressure trip circuitry for the 'A' Main Feed Pump was tested and shown to be set at 61 psig with an associated time delay of 18 seconds. The 'B' Main Feed Pump tripped on low suction pressure about 41 seconds after the suction line rupture.

2. Main Feed Pump Discharge Check Valve Failure

Following the failure of the suction line, the 'A' Main Feed Pump discharge check valve (2-FW-127) was disassembled to determine its condition. Upon disassembly, it was discovered that one of the two disc hinge pins was missing and the disc/seat assembly was dislodged from the valve body. The

hinge pin had evidently been missing for some time prior to the event because of the failure of the tack weld on the hinge pin set screw which allowed the set screw to back out. Based on visual observation, the missing hinge pin did not appear to prevent the disc from seating and, thereby performing its intended function.

The dislodging of the disc/seat assembly from the valve body, however, did render the valve incapable of performing its design function. The disc seat assembly dislocation resulted from a failure of the two clamp assemblies which hold it in the valve body. The failure of these clamps appears to be due to corrosion/erosion of the tab on the lockplate portion of the clamp assembly. Although the deteriorated condition of the check valve did not contribute to the rupture of the suction line, it probably did contribute to the volume of steam and water released following the rupture.

3. Main Feed Pump Suction Pressure Instrument Failure

Following the event, the 'A' Main Feed Pump suction pressure indicator (PI-CN-250A) in the Control Room was observed to be reading offscale high (greater than 1000 psig). Testing was conducted to determine if this was a valid indication and, therefore, indicated an abnormally high pressure at the feed pump suction.

The pressure transmitter (PT-CN-250A) which supplies this indicator is located in the vicinity of the feed pump and was subjected to the steam and water released by the rupture. It was removed and disassembled for inspection and testing. Examination of the transmitter showed no evidence of physical damage such as that which would be expected if the transmitter had been overranged due to an abnormally high pressure transient. Water was discovered in the terminal block section of the transmitter and signs of corrosion were noted on the positive terminals and the printed circuit board. When attempts were made to calibrate the transmitter, the output remained constant at approximately 8 volts, rather than varying from 1 to 5 volts, when pressure applied to the transmitter was varied from 0 to 1000 psig. Once the corrosion was removed from the terminals and the circuit board, calibration was again attempted and successfully completed.

Based on the above, it is concluded that the transmitter failed as a result of the event, giving the offscale high indication, and that an abnormally high main feed pump suction pressure did not actually exist prior to or during the event.

4. Control Rod M-10

Following the reactor trip at 1421, the Individual Rod Position Indication (IRPI) for control rod M-10 was reading approximately 30 steps indicating that the control rod may not have fully inserted. Because a UFSAR analysis has been performed to insure

that the reactor is shutdown following a reactor trip with the most reactive rod stuck at a fully withdrawn position, no safety concern existed. Based on other indications available to the operator, the reactor was shutdown and the operators suspected a faulty IRPI. At 1623, an operator reported that control rod M-10 was indicating fully inserted. An examination of previous reactor trip information indicated that the IRPI for rod M-10 has performed in a similar fashion on two previous occasions. On January 13, 1984, the IRPI for control rod M-10 was reported indicating at 35 steps following a manual reactor trip which was initiated due to closure of a main steam trip valve. Rod M-10 also stuck momentarily or responded slowly at 30 steps following an automatic reactor trip on October 29, 1984. Previous investigations of these incidents by Instrument Technicians found no problems and the rod was verified to be on the bottom (less than 20 steps).

The Instrument Technicians have noted that the voltage reading on rod M-10 is significantly higher than the other IRPI's in the same control rod bank. Therefore, prior to startup of Unit 2, plans are to perform insulation checks and, as appropriate, examine the sensing coils on the M-10 IRPI coil stack. If necessary, hot rod drop tests will be conducted for rod M-10.

IV. EFFECTS OF PIPE FAILURE

A. General Description of Damage

The unit suffered significant damage as a result of the pipe rupture. Much of this damage was visibly apparent. However, additional damage beyond the obvious is being assessed. This section will give a general description of the damage that has been identified and describe the process for identifying any additional damage that may have occurred.

Following the reactor trip, an elbow in the 18 inch suction line to the "A" Main Feed Pump failed catastrophically, ejecting a fragment approximately 2 feet by 3 feet in size and completely severing the suction line. Due to the force of the steam being discharged from the line, the free end of the severed line, since it then had essentially no lateral support, was displaced in a horizontal direction approximately 6.5 feet before becoming wedged against the bottom of the "B" Main Feed Pump discharge line (see Figure IV-1). During this displacement, the line rotated around the point where it connected to the suction of the "A" Main Feed Pump, severely deforming this portion of the line.

The steam being discharged at high velocity from the severed suction line and from the feed pump suction header impacted everything in the immediate vicinity of the break, causing damage to pipe insulation, instrument tubing, cable trays, and other equipment.

The rupture and separation of the suction line severely distorted the pipe support carrying this line. Several other minor pipe supports in the area were damaged and must be replaced or repaired. The majority of the adjacent feedwater and condensate pipes sustained insulation damage during the accident. There is no visible damage to the "A" Main Feed Pump. However, several small valves in the attached auxiliary systems have bent stems.

Damage to numerous conduit and instrumentation supports and raceway channels occurred in the rupture area. This damage includes an approximately 10 foot long channel supporting instrumentation directly in front of the "A" Main Feed Pump.

Motor Control Center 2A1 was exposed to water and steam from the line break. This resulted in a minor arcing in one breaker cubicle after the incident. Visual inspection of the breaker cubicles did not indicate damage. Several cable trays were damaged, being bent and knocked out of position.

The motors for the "A" and "B" Main Feed Pumps were deluged with hot water. There was no visual damage to the "A" Main Feed Pump motors. The inboard motor on the "B" Main Feed Pump sustained some minor damage. There was no visual damage to the "B" Main Feed Pump outboard motor.

Exposed cables in trays in the area of the line break show discoloration. Numerous conduits or conduit support systems were damaged and will require repair or replacement. Lighting fixtures and

panels were deluged with water. Three lights and several runs of lighting conduit were damaged. The Halon control panels and the Pyrotronics fire protection panel had water enter through an open conduit and short out circuits in the panel. Sixty-two (62) fire protection sprinkler heads discharged. The Cardox (CO_2) control station for the Unit 1 and 2 Cable Tray rooms had water enter through openings in conduit and shorted out controls.

Several hundred feet of instrument tubing support systems were damaged. In addition a large number of instruments including pressure switches, gauges, junction boxes, and transmitters show signs of damage and will have to be inspected, repaired, and/or replaced.

A detailed list of damaged components is included in Appendix IV-1.

B. Description of Process of Identifying and Resolving Damage

The Technical Independent Investigation Committee appointed by Virginia Power management had as part of its charter determination of the damage or potential damage to equipment and structures as a result of the accident. The process developed to identify damage or potential damage included:

(1) interviews with station staff and contractor personnel

(2) review of plant data acquisition records

(3) visual inspection of affected areas

(4) appropriate testing of electrical and instrumentation systems in the affected areas

This process was applied to develop the list provided as Appendix IV-1.

The station has an extensive formal process for investigating potential damage, evaluating damage when found, and initiating the necessary design information and work order to restore the damaged equipment and structures to operable status. The damage will be resolved and documented by the work order system (maintenance activities) and the design change process. The technical evaluations and design information from the design change process will be documented in technical reports, Design Changes or Engineering Work Requests.

The Station Nuclear Safety and Operating Committee (SNSOC) routinely reviews the work on safety related systems to insure the maintenance and technical basis for declaring a system operable and to satisfy the plant's design basis safety requirements. As part of the restoration process, SNSOC will also review the work order and design change process documentation on the repair and disposition of all equipment damaged by the incident. This additional review will be accomplished prior to the restart of Unit 2. More information on the restart plans for Unit 1 and 2 is provided in Section X.G.4 and Section X.G.5 respectively.

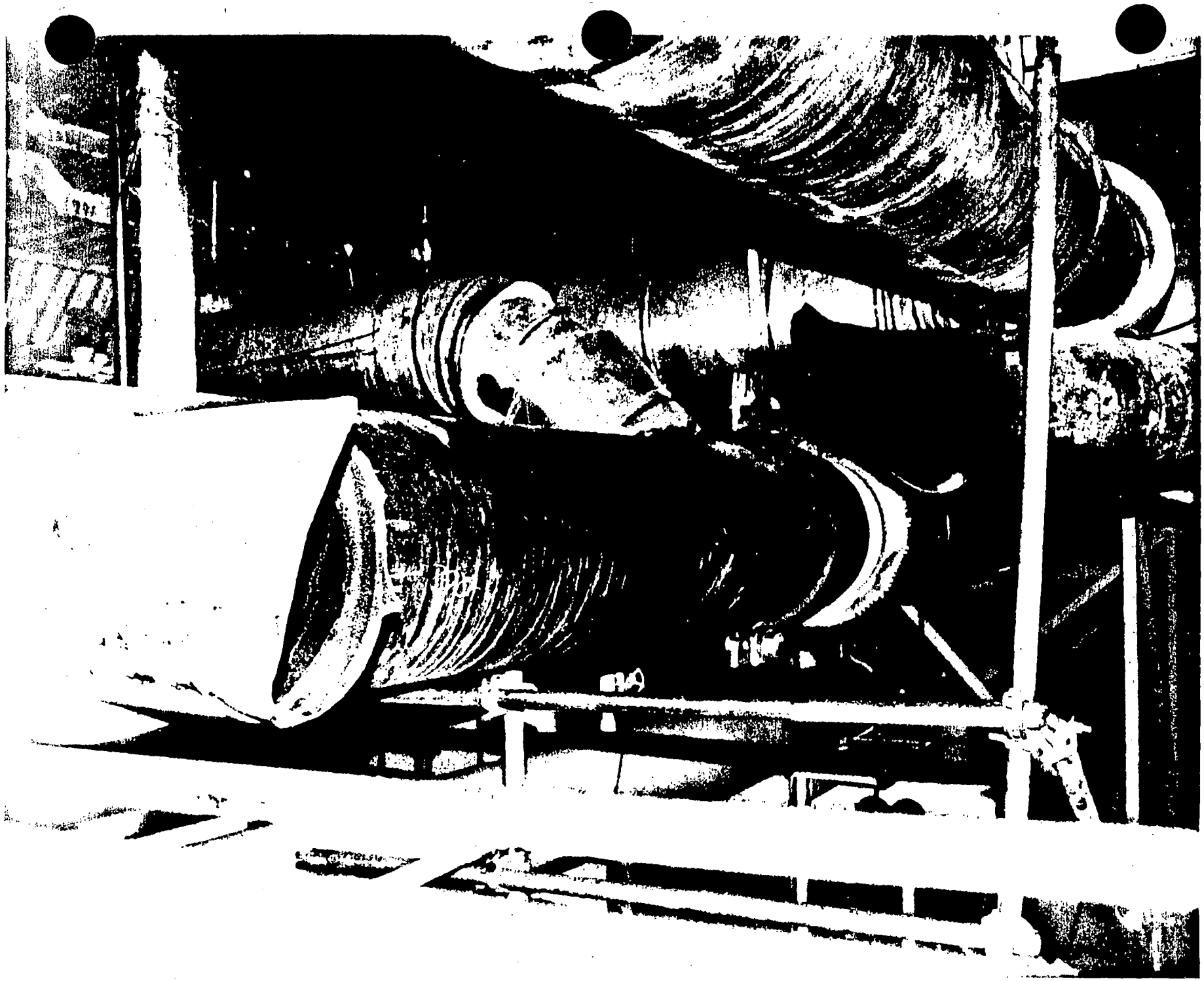


FIGURE IV-1 - Failure site showing complete fracture of 18" diameter elbow.

APPENDIX IV-1

DAMAGED COMPONENTS

Mechanical

1.) 2-FW-P-1A Main Feedwater (FW) Pump - The pump suction line is badly damaged due to pipe whip. The 90° back to back short radius elbows at the pump suction are badly distorted indicating the pump nozzle load allowables had been exceeded. The suction isolation valve and bypass valve, 2-CN-135 and 2-CN-317 appear to be undamaged. A visual inspection of the pump casing, suction nozzle and flange did not indicate structural distress. Several small valves in the attached lube oil and seal cooling water systems have bent stems.

2.) Line 18"-WPCD-133-301 (feedwater pump 1A suction line) - The 90° elbow turning south off the 24"x24"x18" tee (in line 24"-WPCD-131-301 has broken away. The remainder of line 18"-WCPD-133-301 wedged under line 18"-WFPD-102-901 (FW pump 1B discharge line). This caused line 18"-WFPD-102-901 to elevate approximately 1". This has caused the top of line 18"-WFPD-102-901 to contact lines 6"-WRRD-101-601 and 6"-WRRD-103-601 (reheater drain lines to second point feedwater heater 2-FW-E-1A).

3.) 4th pass level drain piping - Line 3"-WRRD-204-601 and 3"-WRRD-206-601 have insulation damage on the elbow upstream of 2-LCV-SD-240B and 2-LCV-SD-240D. Lines 3"-WRRD-200-601 and 3"-WRRD-202-601 have insulation damage where they drop from elevation 37'-3" down to 25'-6". This damage appears to have resulted from the impact of the ejected piece of elbow that ended up in the cable trays east of the pipe rupture.

4.) The majority of adjacent pipes sustained insulation damage during the accident. In addition, a large portion of piping will require insulation removal in order to perform follow-up NDE inspections. All of the insulation will have to be repaired/replaced.

Civil/Structural

1.) The rupture and separation of 18"-WCPD-133-301 severely distorted the pipe support carrying this line. The support, identified as H-62, was a rod suspended spring type hanger and was the only support on this line between the suction header and the feedwater pump 2-FWP-1A suction nozzle.

The design of H-62 includes supplemental building steel; back-to-back channel members (20 ft. long) framed between two beams (W27x94) comprising the mezzanine floor framing (Elevation 35'). The channels were severely distorted as a result of pipe whip loads. Welds connecting the channels to the beams partially failed. Other than slight local distortion in the beam web at the weld failure, the mezzanine floor framing appeared unaffected.

Also supported from the supplemental building steel for H-62 was a support for two bearing cooling lines. The structural channel members comprising this support were damaged and must be replaced.

2.) The ruptured 18" line wedged beneath 18"-WFPD-102-901 causing it to elevate slightly. This appeared to have minimal effect on the supports. After removal of the ruptured line it was noted that the pipe supports appeared unaffected by the incident and spring hanger settings were at or close to their required positions.

3.) Damage occurred at curb plate and handrails comprising a permanent steel platform. This platform is supported and accessed from the 9'-6" elevation and exists just west of feedwater pump 2-FW-P-1A.

4.) Damage was observed to numerous conduit and instrumentation supports and raceway channels. This damage includes approximately 10 foot long channel supporting instrumentation directly in front of pump 2-FW-P-1A.

Electrical/I&C

1.) MCC-2A1 Motor Control Center - The motor control center was exposed to water and steam from the line break. This resulted in a minor arcing in one cubicle after the incident. Visual inspection of the cubicles did not indicate damage.

2.) Safety-related (purple) cable tray C-el. 31'6", section 289 has been damaged. One threaded rod support is bent 10 inches to the east of the original position. The tray is out of position by the same distance. A sheet metal internal divider has been partially torn from the tray. The tray side rail is deformed but sharp edges are not evident in locations which would cause cable damage. The tray cover is damaged.

3.) Safety-related (orange) cable tray C4-el. 29'6", section 289, and non-safety-related cable tray A-el. 30'6", section 289 are damaged. The damaged support indicated in item 2 also supports this tray. The tray side rail is deformed, but sharp edges are not evident in locations which would cause cable damage. The tray cover is damaged.

4.) Steam Generator Feed Pump 2-FW-P-1A motors were deluged with hot water. Visual inspection of the motor does not indicate damage.

5.) Steam Generator Feed Pump 2-FW-P-1B motors were deluged with hot water. Inboard motor 2-FW-P-1B2 main vent screens are missing, and the motor termination box is bent away from the body of the motor.

6.) All motors in the north half of Unit 2, on or below the Turbine Building Mezzine Level, have been exposed to water and steam.

7.) Exposed cables in all trays in the area of the line break show discoloration.

8.) The vertical 6 inch tray, supporting cable 2C5PH1-0, feeding the inboard motor on Steam Generator Feed Pump 2-FW-P1B2 is damaged.

9.) The following conduits or conduit support systems were damaged.

	Length	Conduit Size	Location	Damage Description
a.	20 ft.	2 inch	From C tray El. 31 ft. to SOV-FW250B, north of B pump.	Conduit support and conduit bent.
b.	4 ft	3/4 in. (flex)	SOV-FW250B, north of B pump to local junction box.	Flexible conduit broken and included wires damaged.
c.	4 ft	3/4 in. (flex)	SOV-FW250B, north of B pump to local junction box.	Flexible conduit broken and included wires damaged.
d.	25 ft. (ea.)	(2) 1 1/2" (1) 1" (1) 3/4	From B tray El. 31 ft. junction box at east end of B pump.	Conduit and conduit supports out of position.
e.	15 ft.	1 in.	From vertical conduit to bearing temp. probes on south side of B pump.	Conduit supports loose from pump base.
f.	25 ft.	1-1/2 in.	From B tray El. 31 ft. to south side of B pump	Conduit supports bent, 'T' condulet broken at El. 31 ft.
g.	80 ft.	1 in.	From C4 tray El. 31 ft. north of A pump to to RTD 213A on B pump suction line	Conduit broken above A pump. Supports are damaged.
h.	15 ft	1 in.	From conduit at El. 31 ft. to RTD on A pump suction line.	Conduit is gone. Conduit support is damaged.
i.	30 ft.	1 in.	Lighting under C tray at El. 31 ft. over A and B pump.	Conduit and included wire is damaged.

j.	120 ft.	3/4 in.	From TB-PS-CN217 A/B north of A pump to CN217A	Conduit broken and supports are damaged.
k.	120 ft.	3/4 in.	From TB-PS-CN217 A/B north of A pump to CN217B	Conduit broken and supports are damaged.

10.) Lighting fixtures and panels have been deluged with water. Three lights have been damaged. Several runs of lighting conduit have been damaged.

11.) The Halon control panels in the Unit 1 turbine building basement and the Pyrotronics fire protection panel 1 SW 01 in Unit 1 have been deluged causing the system activation.

12.) Instrument tubing and/or tubing support systems have been damaged as follows:

Length	Size	Location	Damage Description
a. 4 in.	1/2 in. Copper	SOV FW250B, north of B pump.	Tubing is crimped.
b. 6 in.	3/8 in. Copper	SOV FW250B, north of B pump.	Tubing is crimped.
c. 70 ft.	1/2 in. Stainless	F1CFW250BL from north of A pump up to El. 31 ft. then south above pumps.	Support and tubing above pumps are damaged.
d. 50 ft.	1/2 in. Stainless	F1CFW250BH from north of A pump up to El. 31 ft. then south above pumps.	Support and tubing above pumps are damaged.
e. 50 ft.	4-1/2 in. Stainless	F1CFW250AH, AL, BH and BL from north of A pump.	Support under Y line is damaged

f.	2 ft	1/2 in. Copper	LCV-SD-240B and D El. 31 ft. north of A pump	Tubing is crimped.
g.	10 ft.	1/2 in. Copper	LCV-SD-240A and C El. 31 ft. north east of A pump up to El. 31 ft. then west under Y line steel.	Tubing is damaged.

13.) The following instrumentation has been damaged or is suspected of damage.

a. Instrument rack north of "A" feedwater pump

1. PT-CN-250A
2. PT-CN-250B
3. PS-FW-250A (including air supply gage)
4. PS-FW-250A-1
5. PS-FW-250B (including air supply gage)
6. PS-FW-250B-1
7. PT-FIC-FW250A
8. PT-FIC-FW250B

b. "A" feedwater pump recirculation valve station

1. SOV-FW-250A
2. Accumulator tank and support
3. Associated junction box

c. "B" feedwater pump recirculation valve station

1. Limit switches and associated flex conduit
2. Accumulator tank and support
3. SOV-FW-250B (including crimped tubing)

d. "A" feedwater pump local instrumentation

1. 0-30 psi oil pressure gauge (1/4" NPT)
2. 0-250 °F dial temp. indicator - oil cooler
3. 0-250 °F temp. indicator - (in-line with pressure switches)
4. 1/4" sensing line and fitting (1/2"x1/4" reducer oil pressure line on "T" rack - left side of pump)
5. 1/4" oil return line to reservoir (stainless steel)
6. 0-3000 psi pressure gauge (1/2" NPT)
7. All pressure switches on the pump skid

e. "B" feedwater pump instrumentation

1. 0-30 psi oil pressure gauge
2. 0-3000 psi pressure gauge (1/2" NPT)
3. 0-250 °F dial temp. indicator - oil cooler
4. 0-250 °F temperature indicator (in-line with pressure switches)
5. All pressure switches on the pump skid

f. Instruments mounted on I beam adjacent to "B" feedwater pump

1. PS-CN-202B
2. PS-CN-212B

g. Instruments on transmitter rack 274.

1. FT-SD-202A
2. FT-SD-202B
3. FT-SD-203
4. PT-MS-2468
5. PT-MS-208A
6. PT-MS-202

h. RTD-SD-21 (flex conduit from RTD to cable tray has been damaged).

i. Feedwater heaters 1A and 1B inlet temperature gages are pegged high and have water in them.

j. Valve position on FCV-SD-240D has been damaged.

k. Positioners for FCV-SD-204A, B, C, and D were in the blowdown path of the ruptured 18 inch line.

V. PERSONNEL INJURIES AND FATALITIES

A. Personnel Location and Activities at Time of Rupture

Prior to the accident several Daniel Construction Company and Insulation Specialities, Inc. (ISI) employees were working in the Turbine Building basement area. The schematic drawing provided as Figure V-1 shows the location of the injured personnel.

The Daniel Construction Company personnel injured were:

A. O. Blades

D. S. Browning

F. P. Newby

T. D. Smith (died, December 11, 1986)

R. E. Wilkes (died, December 15, 1986)

L. E. Wisecarver (died, December 10, 1986)

The ISI personnel injured were:

L. E. Stevenson

C. W. Matthews (died December 15, 1986)

The Daniels personnel were working on two design modifications unrelated to the feedwater system. One modification was Design Change (DC) 85-07 (On-line Chemistry Monitoring System) and the other was DC 86-03 (Service and Instrument Air Compressor Modification). The ISI personnel were installing insulation on the discharge line from the "A" main feed pump (2-FW-P-1A).

Mssrs. Wilkes and Wisecarver were working in the Turbine Building basement fabricating pipe for DC 86-03. They were approximately 50 feet southwest of the pipe rupture.

Mssrs. Browning and Smith were approximately 20 feet southwest of the rupture. They were working on scaffolding installing instrument lines for DC 85-07.

Mr. Blades was working on the north side of the Track Bay twisting wire for scaffold walkboards being installed for DC 85-07.

Ms. Newby was assigned to Fire Watch duty and was walking up stairs located on the southside of the Turbine Building adjacent to the Track Bay area.

Mssrs. Stevenson and Matthews had been on a scaffold, installing insulation on the discharge pipe from the 'A' main feed pump. When they heard noises in the pipe, they had jumped off the scaffold and were about 20 feet away when the rupture occurred.

B. Extent of Injuries

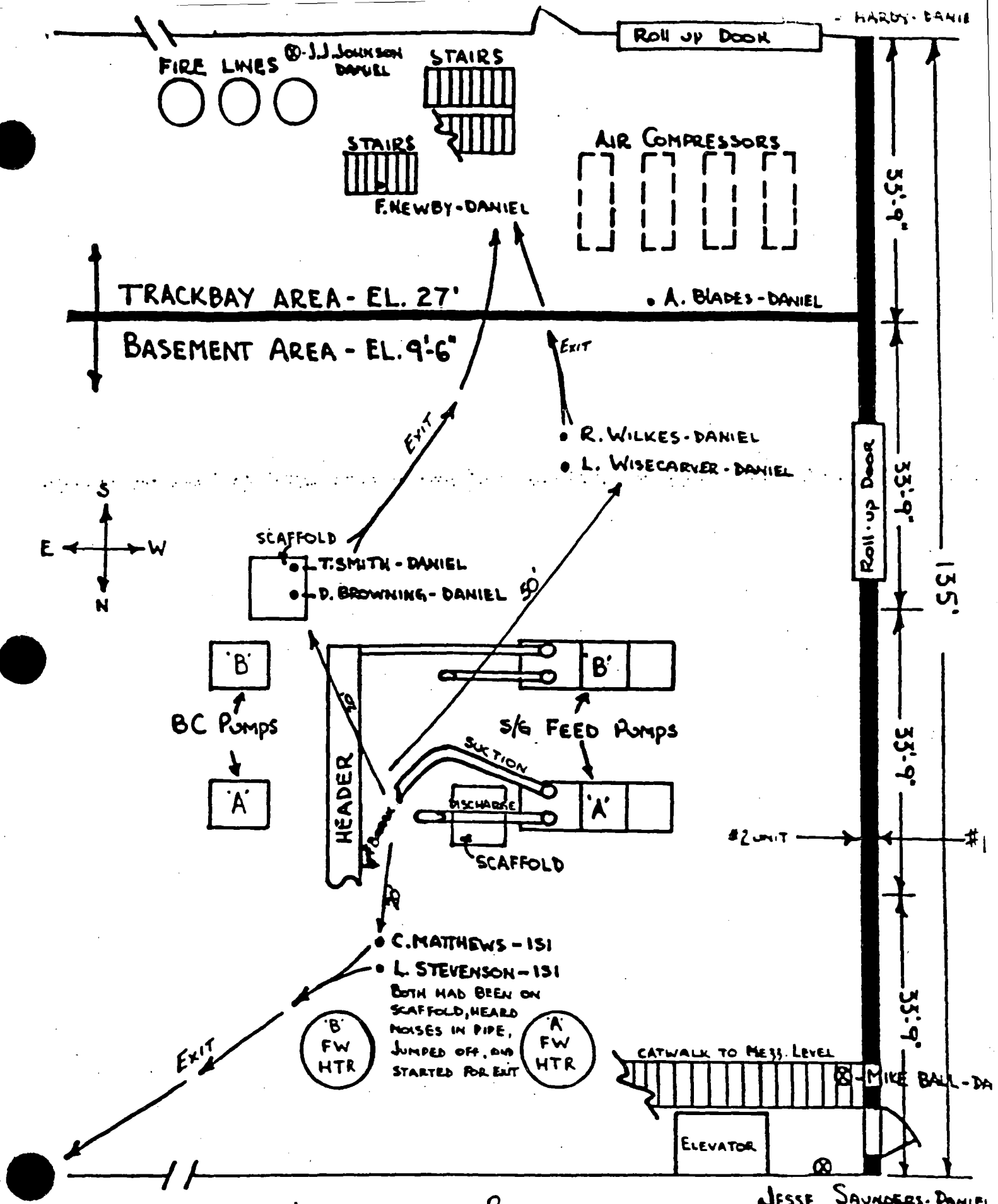
Mr. Blades and Ms. Newby had minor first degree burns. Mr. Blades received treatment at the First Aid Room located in the construction offices adjacent to the plant area and was released. Ms. Newby received treatment at the Smithfield Clinic in Smithfield, Virginia, and was released.

The other six personnel had critical burns. The exact extent of the injuries to these personnel must be obtained from their physicians.

C. Treatment of Injuries and Transport

A complete patient survey on each of the injured employees was performed and oxygen was administered. The clothing was cut away and shoes removed. The burns were then cooled with saline solution, and water and burnsheets were applied. The critically burned personnel were placed on back boards and transported to an area behind the Training Center which is used for a helicopter landing area. The Training Center is adjacent to the site.

Two medical evacuation helicopters were used to transport three of the critically burned personnel from the station to area hospitals. One helicopter was from Nightingale Air Ambulance Service out of Norfolk, Virginia and the other was the Med-flight helicopter from State Police headquarters in Richmond, Virginia. Ambulances from Isle of Wight and Surry County transported the other three critically burned personnel to area hospitals.



INJURED

⊗ = NON INJURED

LOCATION OF PERSONNEL

SURRY POWER STATION - UNIT 2

DEC. 9, 1986

VI. PIPE FAILURE ANALYSIS

A. Background

A field metallurgical investigation was made of the Surry Unit 2 "A" Main Feed Pump suction line failure. The failure occurred at an 18 inch diameter schedule XS WPB elbow as shown in Figures, VI-1 & 2. The elbow material is carbon steel, ASTM A-234, Grade B, which is equivalent to ASTM A-106, Grade B seamless pipe. The nominal wall thickness was 0.500 inches at installation and the elbow had seen service since unit startup in 1973.

The field metallurgical investigation consisted of the following:

- Visual inspection of the system failure location.
- Removal of the fractured elbow from the suction line.
- Visual 5X magnification evaluation and photography of fracture surfaces and elbow surface conditions.
- Ultrasonic wall thickness measurements, on a 2 inch grid pattern, of the failed elbow.
- Metallurgical replicas taken on the elbow at several surface locations.
- Mechanical measurements of elbow thickness.

B. Investigation

1. Visual Evaluation

The visual evaluation of the elbow inside surface revealed a thin wall and dimpled surface appearance (Figure VI-3). This condition has been noted previously, in bulk single phase systems, only in the Westinghouse steam generator J-nozzles.

The J-nozzle surface condition was determined to be the result of a bulk single phase system corrosion/erosion mechanism. This is a mechanism of electrochemical corrosion in rapidly flowing aqueous solutions. Wall loss by corrosion/erosion occurs by gouging-out-patterns on metal surfaces under the simultaneous action of a flowing medium and an electrochemical dissolution.

Both the Surry J-nozzles and Surry feedwater pump suction line demonstrated a similar design geometry consisting of a header or large diameter pipe with a right angle discharge pipe extension and a 90 or 180 degree elbow or turn. This configuration is shown in Figure VI-4 for both components. The turbulent flow created by this geometry, and a possible vapor phase separation locally in the elbow and tee extension, coupled with the low oxygen content (average 4 ppb) feedwater, is concluded to have resulted in the corrosion/erosion which thinned the elbow pipe wall. The corrosion/erosion mechanism in the J-nozzles is known to result initially in a very low metal loss rate followed by a progressively higher nonlinear loss rate once significant thinning has occurred.

2. Ultrasonic and Mechanical Wall Thickness Measurements

Ultrasonic wall thickness measurements and direct mechanical measurements taken on the elbow indicate a gradually sloping wall thickness loss over much of the surface. At several locations, usually near welds, a localized cavity has been created in the elbow surface. The remaining wall thickness at

these localized areas has been measured as low as 0.048 inches while adjacent locations may be 0.090 inches to 0.140 inches in thickness.

3. Metallurgical Structure Replicas

Field metallurgical replicas taken on the surface of the failed elbow indicated a carbon steel pearlite/ferrite microstructure typical of ASTM A-106 Grade B chemistry pipe. No distortion of the structure or signs of strain where observed in any replica.

4. Fracture Surface Examination

Visual examination of the fracture surface at 5X magnification revealed an apparent ductile tearing mode, plane stress, slant fracture over most of the surface. Tears which may represent highly localized tensile overload areas are evident at two thin wall cavity locations shown in Figures VI-5, VI-6, and VI-7. Numerous defects of small size were observed along the fracture surface. Generally these defects represent laps, laminations, and inclusions less than 0.5 inches in length. At one thin wall location, near an apparent overload tear, an inclusion or lamination was observed which may represent the final slant fracture (unstable ductile tear) initiation location. The slant fracture surface condition represents most of the failure surface.

C. Probable Failure Sequence

Based upon the observations made in Section B above, a probable sequence of stress and failure events leading to the final pipe rupture is as follows:

- The system is operating normally. System pressure is approximately 367 psig, and system temperature is approximately 374°F. Wall thickness of the elbow is as low as 0.048 inches in highly localized areas and 0.100 inches over a somewhat more general area. Because of the high system temperature, the toughness of the elbow material is on the upper ductility shelf. Local membrane stresses are near yield at low wall thickness locations

- The system undergoes an upward pressure transient which results in a localized tensile overload failure (cavity blowout) in a thin wall corrosion/erosion cavity. The tensile overload tear arrests, and does not develop into the unstable crack tearing mode. Water flashing into steam from the localized tear is heard by station personnel.

- The steam flash continued for a few seconds as pressure continued to increase in the elbow. In the area of the small tensile rupture, or at a second thin wall area, the pipe wall experienced an increasing stress intensity approaching the upper shelf tearing resistance of the carbon steel elbow material. An unstable ductile tear developed, possibly at a defect site. The pipe ruptured, ejecting a fragment from the elbow upward from the fracture surface.

D. Chemistry

The chemistry of the water plays a role in the corrosion/erosion process. In particular, the absence of oxygen accelerates the process. Experimental studies have shown that pH, hydrazine and ammonia may also effect the process.

From startup in 1972 through 1977, the Surry units were on phosphate steam generator chemical treatment, using cyclohexylamine to control condensate pH and hydrazine to control O_2. In April of 1977, the treatment was changed to all volatile treatment using morpholine for pH control and hydrazine to control O_2. Since 1980, following steam generator replacement, ammonia has been used for pH control, replacing morpholine, and hydrazine has been used for O_2 control.

During all these periods, the pH levels have been in the range of 8.8 to 9.2 and O_2 levels have averaged about 4 ppb, except for transients of short duration.

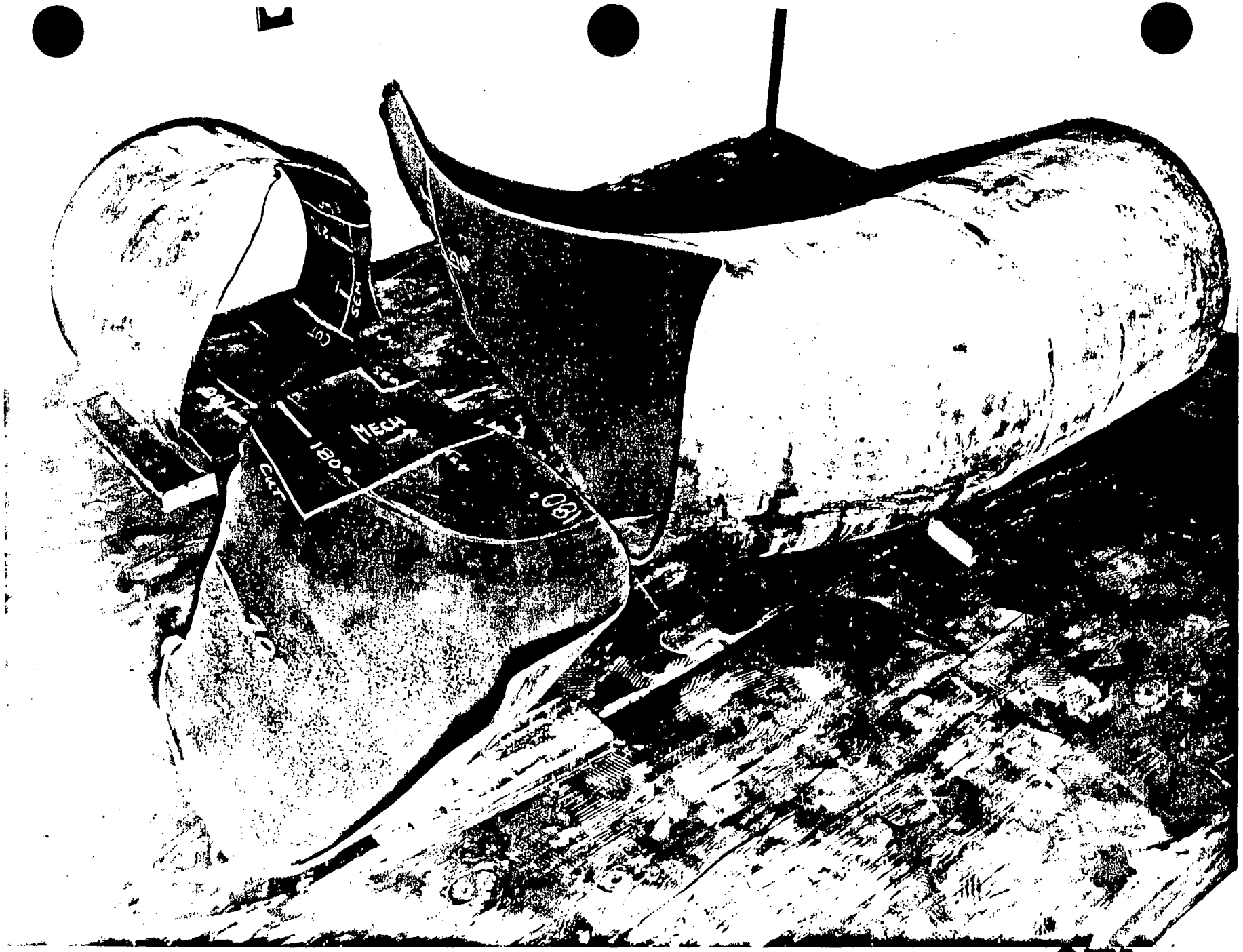


FIGURE VI-1 - Failed 18" diameter elbow after removal showing relationship of fractured sections.

Photo by THOMAS F. KELSEY

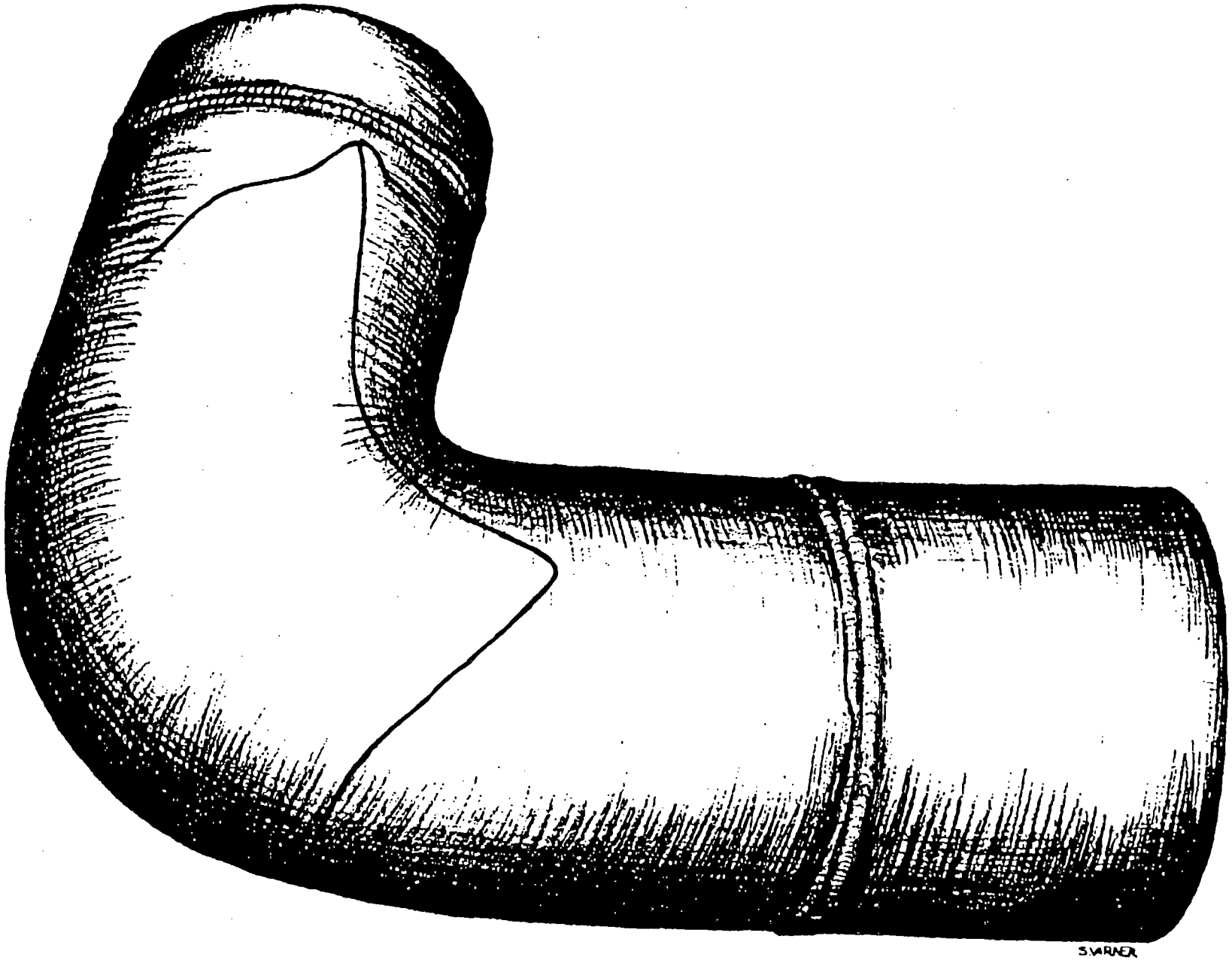


FIGURE VI-2 - Artist rendering of intact 18" piping elbow with failed section drawn in.

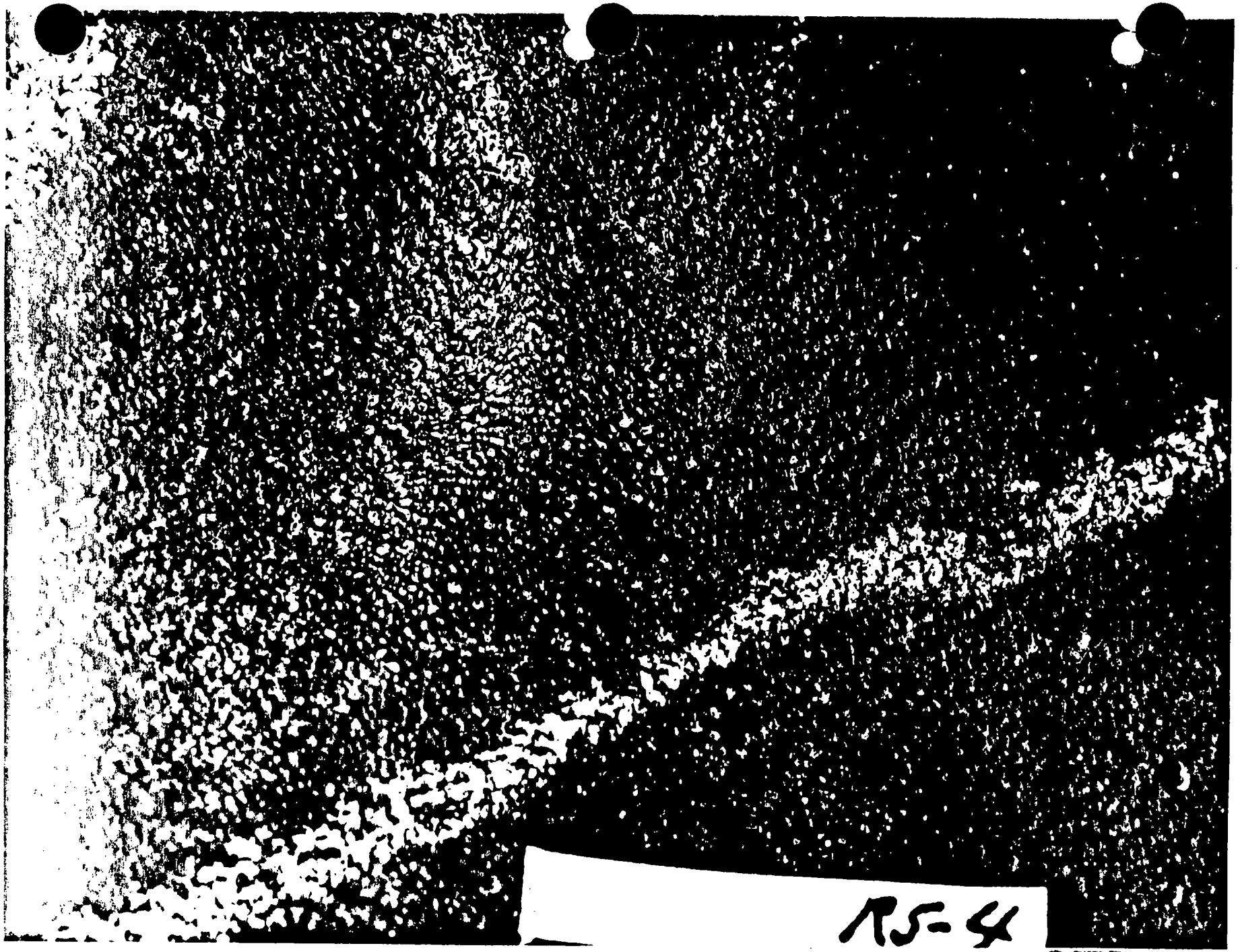


FIGURE VI-3 - Macrophotograph of interior elbow surface showing localized wall thinning and dimpled surface appearance.

THOMAS F. KELSEY

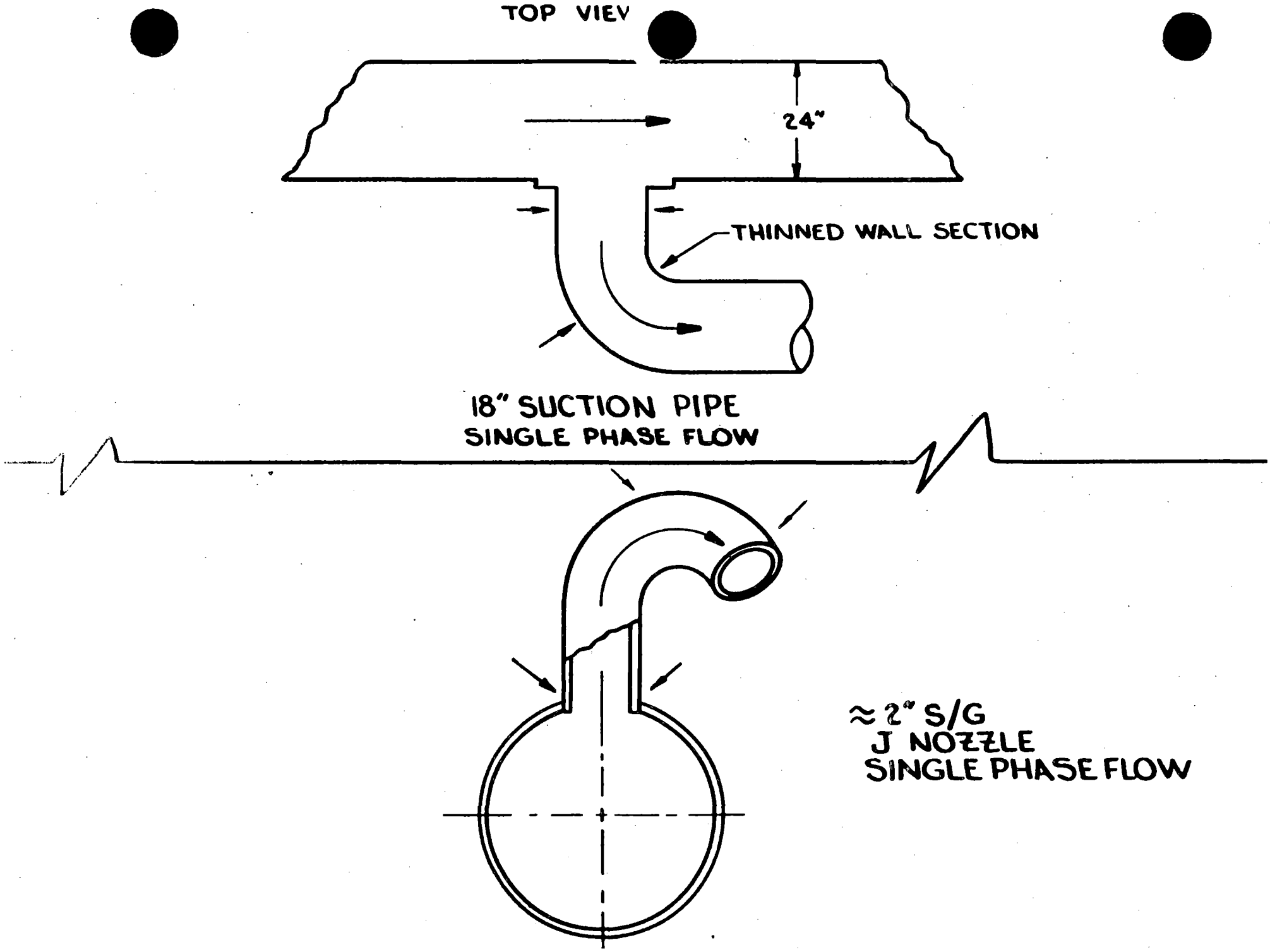


FIGURE VI-4 - Schematic diagram of Surry 18" feedwater suction line and steam generator J-nozzle showing similarities in design geometry.

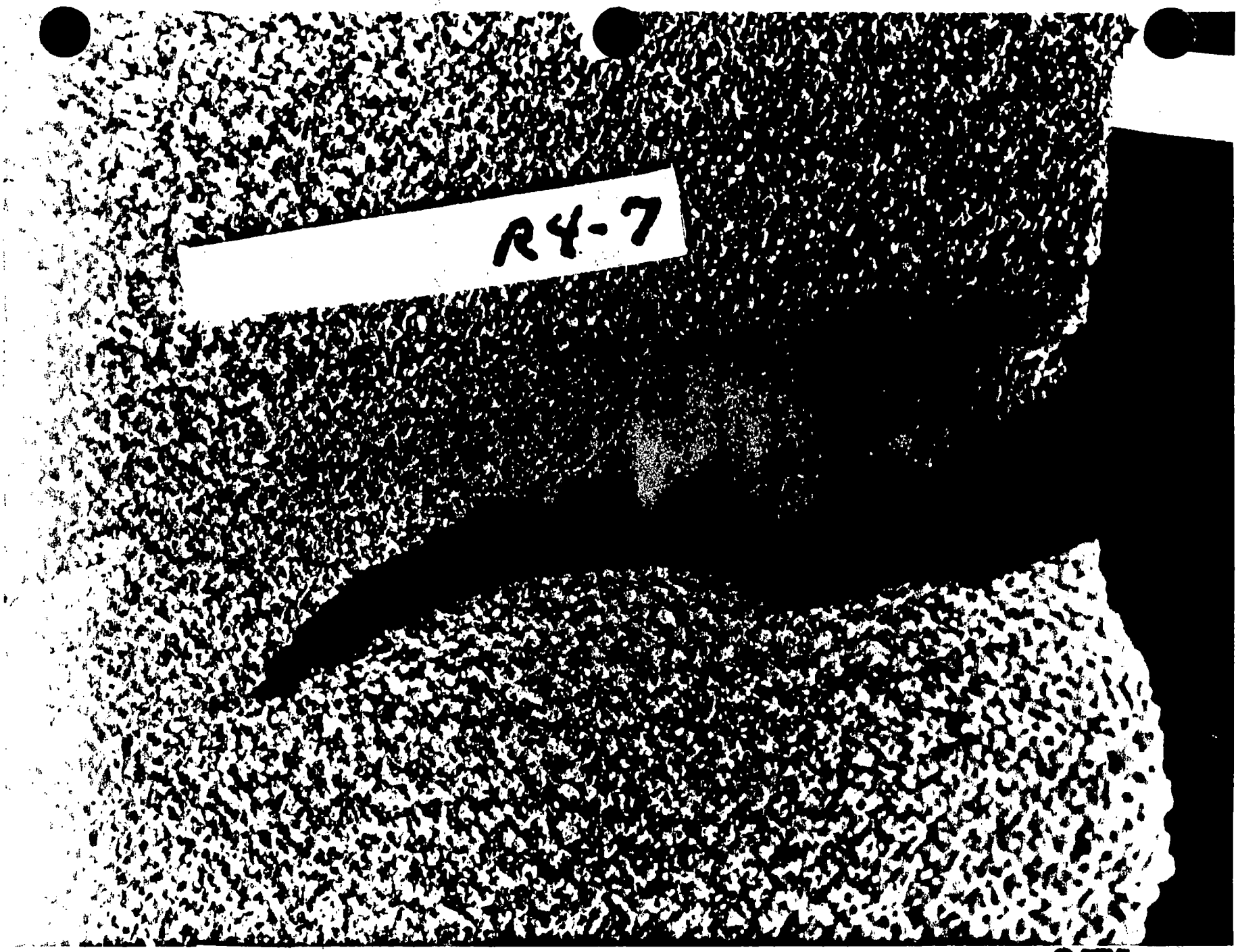


FIGURE VI-6 - Macrophotograph of thin wall cavity shown in Figure VI-1 showing ductile tear.

PHOTO BY THOMAS F. KELSEY

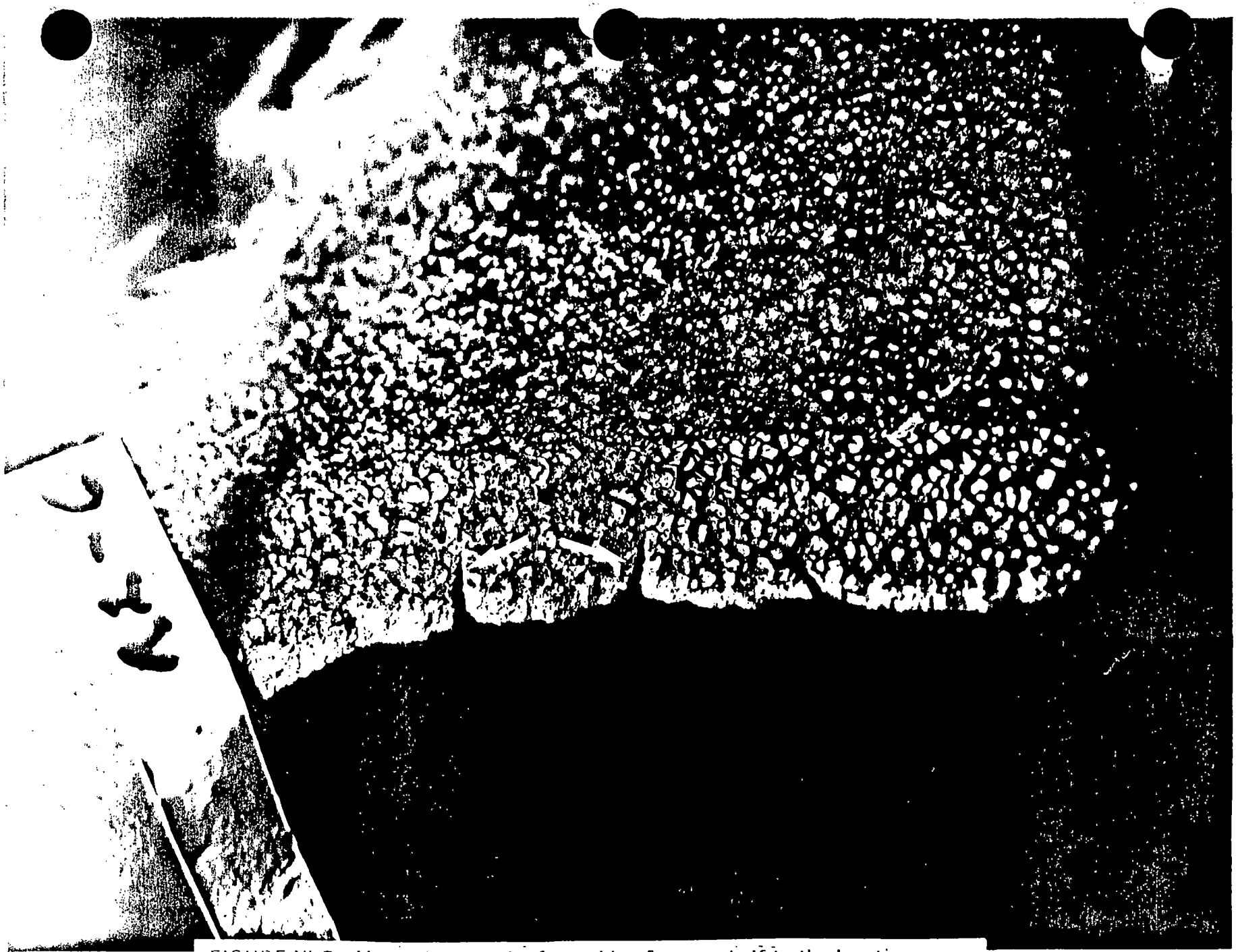


FIGURE VI-7 - Macrophotograph of matching fracture half to the location shown in Figure VI-1. Localized wall thinning and membrane tear (arrows) are evident.

PHOTO BY THOMAS F. KELSEY

VII. Operator Response to Incident

The response of operators to the reactor trip and feedwater pipe rupture was timely, professional and appropriate. The event was properly diagnosed and appropriate emergency procedures implemented. The STA reviewed the Critical Safety Functions Status trees and found plant parameters within safe bounds. In conjunction with other plant personnel, Operators who were not involved in responding to the reactor trip and mitigation of the feedwater pipe rupture initiated searches of the Unit 2 Turbine Building to rescue injured personnel. In addition, Operators assisted in evacuation of personnel from areas affected by actuation of the Halon and CO_2 Systems.

Emergency Procedure (EP) 1.00, Reactor Trip/Safety Injection, was completed up to step 4. Since a safety injection was not in progress, EP-1.00 directed the operators to transition to EP-1.01, Reactor Trip Recovery, placing the reactor in a safe shutdown condition. Operating Procedure (OP) 1F, Shutdown Margin Calculation, was completed to verify Technical Specification shutdown margins. The normal operations cooldown procedures, the OP-3 series, were initiated as directed in an orderly transition from EP-1.01.

As directed by the Emergency Procedures, Emergency Plan Implementing Procedure (EPIP) 1.01, Emergency Manager Controlling Procedure, was initiated. Based on a review of EPIP 1.01, the emergency was classified

as a "Notification of Unusual Event" (NOUE) and State and local authorities were notified. In addition to EPIP 1.01, the following procedures were utilized:

1) EPIP-1.02, Response of Unusual Event
2) EPIP-2.01, Notification of State and Local Governments
3) EPIP-2.02, Notification of NRC

When the decision to escalate to an Alert was made, the EPIPs listed in Table VII-1 were implemented by the operators and emergency response personnel as appropriate.

The alert was terminated at 1623. The State, local and NRC notifications were made and the EPIPs were completed. Additional information on implementation of the Emergency Plan is provided in Section X.F.6.

TABLE VII-1

EMERGENCY PLAN PROCEDURES IMPLEMENTED DURING DECEMBER 9, 1986 ALERT STATUS

1)	EPIP-1.03	Response to An Alert
2)	EPIP-2.04	Transmittal of Plant Status and Core Assessment Data
3)	EPIP-3.01	Callout of Emergency Response Personnel
4)	EPIP-3.02	Activation of Technical Support Center
5)	EPIP-3.03	Activation of Operational Support Center
6)	EPIP-3.04	Activation of Local Emergency Operations Facility
7)	EPIP-4.01	Radiological Assessment Director Controlling Procedure
8)	EPIP-4.02	Radiation Protection Supervisor Controlling Procedure
9)	EPIP-4.14	In-Plant Monitoring
10)	EPIP-4.15	Onsite Monitoring
11)	EPIP-4.17	Monitoring of OSC and TSC
12)	EPIP-4.19	Radio Operations For Health Physics Monitoring
13)	EPIP-4.27	Dose Control Emergency Response
14)	EPIP-4.29	TSC/LEOF Radiation Monitoring System
15)	EPIP-5.03	Personnel Accountability
16)	EPIP-5.08	Damage Control Guideline

VIII. FACTORS WHICH POTENTIALLY COMPLICATED RESPONSE TO THE INCIDENT

A. Security

The pipe rupture resulted in water entering the card reader located outside Vital Battery Room 2B, Unit 2 Turbine Building Basement. The water intrusion caused the Security System data line to become inoperable. The inoperable data line prevented access to areas via the card reader system. Roving security officers immediately were dispatched to provide access. Exit from these areas could be accomplished by using emergency exit devices.

The excessive CO_2 discharge in the cable tray room resulted in the Security radio repeaters becoming temporarily degraded. These repeaters provide for clearer radio communications by broadcasting amplified signals through the plant. With the degradation of the repeaters, direct communications between portable hand sets was used. The need to repeat a transmission or relocate to establish effective communication may have complicated response to the incident. However, needed communication was accomplished using radios or the station gai-tronics system.

B. Fire Protection System Actuation and Main Control Room Habitability

Within a few minutes of the pipe rupture, the automatic Halon fire protection system actuated followed by a similar actuation of an automatic CO_2 fire protection system. The Halon system protects the Unit 1 and 2 Emergency Switchgear rooms located on the level immediately below the Main Control Room (MCR) area. The CO_2 system protects the Unit 1 and 2 Cable Tray rooms located on the level im-

mediately above the MCR area. In addition, 62 Unit 2 Turbine Building fire protection sprinkler heads discharged. Two of these sprinkler heads were located outside of the Unit 2 Cable Tray rooms. Within approximately ten minutes, Operations and Loss Prevention personnel verified the area had been evacuated and started ventilating them.

The discharge of the Halon system resulted in undesirable in-leakage of Halon into the MCR through floor penetrations in the Unit 1 Computer Room and through the Control Room Emergency air bottle discharge piping. The CO_2 also penetrated the MCR area when the door to the MCR Annex (MCRA) from the Unit 2 Turbine Building was blocked open to facilitate personnel movement into the MCRA and accommodate recovery activities in the Unit 2 turbine building hallway. The door to the MCR from the MCRA was also open with a security watch posted in accordance with normal procedure following a reactor trip.

When the Halon was observed in the MCR and MCR personnel reported some physical discomfort, the Control Room Emergency Supply Fans (1-VS-F-41 and 2-VS-F-41) were started, restoring the air quality in the MCR area. Prior to starting these fans, the people in the MCR and MCRA reported varying degrees and combinations of effects including shortness of breath, dizziness, and nausea. These symptoms are primarily attributed to the CO_2 since they were reported in the MCRA and on the Unit 2 side of the MCR near the door to the MCRA. Operators on the Unit 1 side of the MCR, where the haze from the Halon in-leakage was reported, did not experience effects that hampered their ability to operate.

The Halon and CO_2 in the MCR area did not adversely affect operator actions. Bottled air systems were available and their utilization was evaluated.

In addition to the affects on MCR habitability, station activities were potentially impacted by:

1. Approximately one inch of water in Unit 2 Cable Tray room around floor penetrations, allowing water to drip from the MCR ceiling behind the Unit 2 vertical control board.
2. The CO_2 discharge in the Unit 1 Cable Tray Room temporarily disabled the repeater from the Security frequency (hand sets were still functional).
3. Undesirable in-leakage of CO_2 in an Instrument Shop area and hallway below Mechanical Equipment Space No. 1.
4. CO_2 in the stairwell behind the MCR.
5. The loss of the entire CO_2 system when the main CO_2 storage tank emptied as a result of excessive discharges to the Cable Tray Rooms.

Plant personnel responded well to both the accident and the resulting effects of the fire protection system actuations. Fire watches were posted immediately in the Unit 2 Turbine Building, Cable Tray rooms, Cable Vaults, Emergency Diesel Generator rooms, and Emergency Switchgear rooms.

C. Communication Difficulties

The Nuclear Regulatory Commission Emergency Notification System (ENS) telephone in the Control Room had some background noise. When communication was shifted to the ENS telephone in the Technical Support Center (TSC) background noise increased. Contact was established and maintained using a commercial line. The ENS telephones have since been checked and found to be acceptable.

Because of the number of critically injured personnel, the Control Room contacted both Station Security and the System Operator. Station Security reported that they had already contacted Nightingale and the Nightingale med-vac helicopter was enroute to the station.

Following notification from the Surry Control Room, the System Operator contacted System security with the details and requested the "med-vac helicopter".

System Security, according to their procedures, contacted Station Security to confirm the need for the helicopter and were told that a med-vac helicopter was enroute. System Security relayed the information to the System Operator. The communications had become confused between the use of the generic term "med-vac" helicopter and the Med-Flight med-vac helicopter service.

The result was that no one at the System office had requested that Med-Flight respond to the emergency at Surry. This fact became apparent in communication with the State Department of Emergency

Services. The State recognized that Med-Flight had not been dispatched when the report to State and local Governments was received. This report advised the State at the declaration of the Notification of Unusual Event and listed support which had been requested, including Med-Flight. The State then dispatched the Med-Flight helicopter.

The overall result was a delay of approximately 30 minutes in dispatching the Med-Flight helicopter. However, this delay did not impact the first aid and subsequent medical treatment of the critically injured individuals.

The Insta-Phone to the State Emergency Operations Center and the dispatch offices of localities within 10 miles of the station was used to supply information to State and local governments. Localities reported difficulty receiving information over the Insta-Phone when transmission was attempted from the TSC. The Insta-Phone in the Control Room was used successfully. The TSC Insta-Phone has been checked and localities now report that reception is clear.

The First Aid Team reported difficulties establishing radio communications. Direct communications with the control room was finally established using the gai-tronics system.

Communications with plant personnel was accomplished by use of the emergency alarms in conjunction with the gai-tronics system. Some areas reported difficulties understanding the announcements over the

gai-tronics. Some of the areas reporting difficulties are located outside the protected area where full gai-tronics coverage is not expected.

D. Call-out of Medical Transport Helicopters

Station procedures provide for the Control Room to notify Station Security to contact Nightingale for emergency transport of injured individuals requiring a medical evacuation (med-vac) helicopter. These procedures also provide for the Control Room to notify the Virginia Power System Operator if the State Police Med-Flight med-vac helicopter is required. The System Operator then contacts the System Security Office which contacts the State Police to dispatch Med-Flight.

IX. SHUTDOWN OF SURRY UNIT 1 AND NORTH ANNA PIPE INSPECTIONS

A. Surry Unit 1 Actions

On December 10, 1986, following preliminary inspections of the Unit 2 pipe rupture, metallurgists reported to management that the probable cause of the pipe failure was thinning of the pipe wall from the inner surface due to a bulk, single phase corrosion/erosion mechanism. The inspection results are presented in Section VI.B. Because the Unit 1 feedwater piping design is similar, the metallurgists recommended inspection of Unit 1 piping.

Virginia Power management immediately decided to shut Surry Unit 1 down to inspect the wall thickness of piping. However, shutdown of Surry Unit 1 was not initiated until Unit 2 was in a stable cold shutdown condition and the full attention of station personnel could be dedicated to the orderly shutdown of the operating Unit. In the interim, Unit 1 turbine building access restrictions were strengthened.

Surry Unit 1 shutdown commenced at 1730 on December 10th, and the unit was taken off-line at 2247. The Unit 1 reactor was in the cold shutdown condition at 2123 on December 11th.

The Surry Unit 1 piping inspections identified pipe wall thinning in several condensate and feedwater piping configurations; the results are being evaluated. A comprehensive secondary piping inspection program is in progress.

B. North Anna Piping Inspections

When pipe wall thinning was confirmed on Surry Unit 1 main feedwater pump suction piping, Virginia Power management expedited the inspection of pipe wall thickness on similar piping at the North Anna Power Station. After formulation of the inspection procedures and program, North Anna Unit 1 was reduced from 100% power on December 25, 1986, to 20% at approximately 0100 on December 26th. Following prescribed isolations and verification of temperatures below 100°F, the main feedwater pump suction piping and header and the high pressure heater drain pump discharge piping to the header were non-destructively examined. Some 4,900 inspection points were examined, and all locations were above the minimum pipe wall thickness required. The main feedwater pump suction piping and header wall thickness were within the original pipe manufacturing specifications (±12.5% of design), and the high pressure heater drain pump discharge piping was no more than 15% below the original specifications. Since no abnormal pipe wall corrosion/erosion had occurred, Unit 1 was subsequently returned to full power operations at 2147 on December 27th. North Anna Unit 2 and additional Unit 1 piping inspections will be performed during upcoming outages, following development of a revised piping secondary inspection program.

X. RECOVERY ACTIONS

A. Pipe Evaluation

1. Background

There is sufficient experimental data to understand and recognize the bulk single phase corrosion/erosion (C/E) mechanism and establish that it is a complex phenomenon. However, there is very limited data available based on industry experience. The available literature draws a correlation between "wet" steam two phase C/E and bulk single liquid phase C/E. The primary parameters that are tied to the potential for bulk single phase C/E are as follows: 1) carbon steel, 2) high fluid velocities, 3) a pH range between 8.8 and 9.3, 4) high purity water, 5) temperature (195-440°F) and, 6) low oxygen content of the water (low ppb). These parameters relate to the rate of buildup and removal of a protective magnitite (Fe_3O_4) layer on the pipe wall. The resistance of steels to C/E increases with alloying. Alloys with greater than 12% Cr are virtually immune to C/E. The system pressure is indirectly related. As the degree of subcooling decreases, the susceptibility to two phase C/E increases.

The oxide layer is established by three chemical processes. First, a continuous film is developed by direct water contact. Second, an internal layer forms by progressive migration of oxygen toward the metal surface. Third, the protective external layer is created by migrating Fe^{++} ions. At higher temperatures and with higher oxygen

concentrations the conversion of $Fe(OH)_2$ to an external protective layer of Fe_3O_4 is more rapid. At lower temperatures the magnetite formation process is slow. In regions with high velocities the external layer is removed.

Since the bulk single phase C/E mechanism was not recognized by the industry to be of concern, inspection of bulk single phase systems such as condensate and feedwater has not been conducted as a general practice. Based on industry experience with two phase C/E, most utilities do routinely perform inspections on secondary systems where two phase C/E may be present such as extraction steam and steam drains. Surry Power Station has had such a program in place for several years.

2. System Selection Criteria

Based on the above information, the following criteria were established to select systems to be inspected:

0 System handles water or steam

0 System piping is carbon steel

0 System temperature is greater than 195°F

0 System is deoxygenated (< 5ppb).

These criteria will be verified by inspection of specific locations within systems outside these criteria, including safety related systems, such as, the Auxiliary Feedwater System (oxygenated and less than 195°F), Charging System (stainless steel) and Condensate System prior to 4th point heater (Less than 195°F).

3. Inspection Scope

The systems to be inspected were chosen for one of three reasons: 1) to verify that C/E is not present in bulk single phase systems outside the selection criteria, particularly in safety related systems, 2) to confirm the condition of two phase systems inspected by the existing secondary pipe inspection program, and 3) to determine the condition of systems which meet the bulk single phase selection criteria described above. The list of systems to be inspected is shown in Table X-1. The reasons for eliminating remaining systems from the pipe inspection program are provided in Table X-2a and X-2b. Inspection points were selected in each system based on fluid velocity and geometry with geometry being the overriding parameter since the velocities and temperatures are relatively constant within each line segment. Results from these inspections will provide data to correlate C/E as a function of temperature, velocity and geometry. A rating scheme to identify potentially high C/E wear regions in single phase flow lines is described in Table X-3.

4. Inspection Method

The presence of C/E can be detected by determining if generalized pipe wall thinning is present. The presence of generalized pipe wall thinning can be detected by measuring wall thickness using ultrasonic (UT) inspection techniques. The thickness measurements are taken at numerous locations on the systems identified for inspection, with concentration on the geometries most susceptible

to C/E such as elbows, tees, laterals, and reducers. Readings are also taken at intervals along straight runs of pipe. The points to be inspected on the elbows, tees, laterals, and reducers are shown in Figures X-1,2,3,4, and 5.

5. Acceptance Criteria

The pipe wall thickness acceptance criteria uses actual UT measured wall thicknesses of the piping to develop corrosion/erosion wear rate, which is used to predict when the pipe wall thickness would approach its code minimum wall. Therefore, the acceptance criteria provides guidance on determining if a section of piping needs to be replaced immediately, projected to be replaced at some future time in its operating life, or will be monitored by inspection during its operating life.

The general formulation for the pipe wall thickness acceptance criteria is as follows:

$T_a - nW_r \geq Tm$, where

T_a = minimum as found UT wall thickness measurement

n = projected remaining operating time in years

W_r = calculated yearly wear rate

T_m = calculated code minimum required wall thickness in.

W_r is calculated as follows:

$$W_r = \frac{T_n - T_a}{y}, \text{ where}$$

T_n = maximum nominal wall thickness

= T_{nom} (nominal wall) + Manufacturing tolerance

y = actual operating time in years

(hours critical converted to years)

Thus, if the lowest actual measured component wall thickness minus the maximum wear expected in a remaining period of time of operation is greater than or equal to the code minimum required wall thickness, then the component meets the acceptance criteria.

Substituting the W_r definition into the general formulation equation and solving for T_a yields a more useful form of the acceptance criteria as follows:

$$T_{acc} = T_n - \frac{y}{y+n} (T_n - T_m), \text{ where}$$

T_{acc} = the acceptance criteria

Note that $T_N - T_m$ is the total wear allowance of the component. The wall thickness criteria equation can be used to put the piping components into various acceptance categories, as shown in Table X-4, by comparing the as found wall thickness, T_a, to the acceptance criteria, T_{acc}.

The acceptance criteria formula developed herein was formulated using a linear wear rate based on actual wall thickness UT measurements of the various piping components. The acceptance criteria formula has the following conservatisms in its formulation:

(1) Pipe and fittings were assumed to have been installed with a maximum nominal wall thickness, which was defined as nominal wall plus maximum manufacturer's tolerance for pipe. Therefore, calculated wear rates are conservative. (For pipe and fittings that did not meet $Tacc/_{n=t_1}$, but were greater than T_m, an evaluation was done using T_{Nom} to calculate the wear rate, if the UT data suggested the component was supplied at or below nominal wall thickness).

(2) For wear rate calculations, both Units 1 and 2 were assumed to have been in operation nine (9) years, which is slightly less than the time of critical operation of each unit. This does not include any noncritical operation time or any unit lay-up time. This fact adds conservatism to the calculated wear rates as C/E or other corrosion mechanisms could have occurred during the times that were not considered for wear rate calculations.

(3) The value for n, number of years of operation remaining for a component with its calculated wear rate, was chosen as the time to reach a future refueling outage plus an additional 1/2 year or 1 year depending on the acceptance category.

The above conservatisms in the acceptance criteria formula easily justify its use as a very conservative criteria for replacement or inspection of components in the secondary side piping.

The basis of comparison for acceptance or rejection of a component is the calculated code minimum required wall thickness for the component. The code minimum wall is determined with the assumption that the pipe wall is at uniform minimum wall thickness over the entire pipe circumference. However, the wall thinning resulting from C/E can be non-symetric in nature and, therefore, the minimum wall thickness measured may not extend around the entire circumference of the pipe. Because a component can withstand the pressure used in the code minimum wall calculation with local wall thicknesses lower than code minimum wall, an additional conservatism exists in the criteria. The UT inspection procedures being used have a high confidence level of locating components that are experiencing general area wall thinning that would result in catastrophic failure of the component. The possibility of a small failure (pin hole leak or small blowout) in a component due to other corrosion mechanisms exists because of the inspection grid layouts, but even this possibility is considered very unlikely because inspection procedures call for scanning to be done between grid points if thicknesses near minimum wall are measured.

The validity of the acceptance criteria will be confirmed by:

1. Visual inspections of the removed components.
2. Periodic UT inspections of components in key

locations in the secondary system piping to substantiate wear rates.

6. Component Replacement

Except for two items, components identified for immediate replacement based on the acceptance criteria will be replaced. The replacements will utilize materials and configurations similar to that used during initial construction. One exception is the 18 inch suction line tap off from the 24 inch header to the 'A' Main Feed Pump which is being reconfigured to use a 45° lateral, instead of a 90° tee. This will give a less radical change in flow direction at this point, reducing the likelihood of C/E.

The second exception will utilize a code weld repair in lieu of component replacement. The repair will be made on two steam generator feedwater lines (A and B steam generators) inside containment on Unit 2. The two indications involve a spool piece between the loop seal and a reducer just upstream of the steam generator. These spool pieces were installed in 1979 as part of the steam generator replacement project.

A detailed summary of the completed component inspection and replacement for Unit 1 is shown in Table X-5 and for Unit 2 in Table X-6.

7. Post-Replacement Testing and Inspection

A description of the process which will review the completed work is found in section X-G.

The piping will be replaced in accordance with NUS-20 and Section B31.1 of the Boiler and Pressure Vessel Code. The new piping welds will be tested in accordance with ASME Section IX. The weld repairs will be made in accordance with ASME, Section XI, Article IWA 4100 and performed in accordance with the Design Specification and Construction Code. The required hydrostatic test and radiography will be completed and a QC verification will be obtained.

Approximately 6 months after startup, each unit will be shut down for feedwater piping inspection and reevaluation of erosion rates to verify that our estimates of wall thinning rates are conservative. Inspections beyond the first inspection will be determined based on the results of the first inspection and the information and knowledge known at that time.

The "Secondary Piping Inspection" procedure SUADM-M-33 will be modified to incorporate changes to the inservice piping examinations on secondary systems. The changes will expand the scope of the program for two-phase systems and add examinations of the feedwater and condensate (bulk single phase) piping systems.

In addition, Ultrasonic examination of the feed water ring on at least one steam generator will be performed during the next refueling outage on each unit. The feed ring will also be inspected when the 'J' tubes in a steam generator are inspected. Such inspections are included in inspection programs every third refueling outage.

In summary:

1) Virginia Power has determined the status of secondary piping systems within the plant by an extensive inspection program.
2) A conservative model for predicting the rate of pipe wall thinning was developed based on experimental data, the limited industry experience available, and the inspection results.
3) The model specifies criteria under which pipe fittings will be replaced immediately.
4) The model also identifies conservative criteria for further replacement and/or inspections of piping areas where the rate of thinning is not so fast and the pipe is above allowable piping minimum specifications.
5) The program includes additional inspections in the near term (6 months) and beyond to provide information for confirmation or modification of the model.
6) As additional inspection information and other industry data is evaluated, decisions will be made on a long range program that may include modification of piping geometry and material.
7) Future inspections are planned to confirm that corrosion/erosion does not effect the high alloy piping in primary systems.

TABLE X-1

PIPING SYSTEMS TO BE INSPECTED

SYSTEM
CONDENSATE & FEEDWATER
MAIN STEAM
MOISTURE SEPARATOR DRAIN LINES
STEAM GENERATOR BLOWDOWN SYSTEM
FLASH EVAPORATOR
LOW PRESSURE HEATER DRAINS
AUXILIARY STEAM
1st & 2nd PT. EXTRACTION STEAM
3rd & 4th PT. EXTRACTION STEAM
5th & 6th PT. EXTRACTION STEAM
* AUXILIARY FEED
* CHARGING

* These systems were not within the scope of recommended inspections, but were added to the scope of the Unit 1 inspections in order to validate the stainless steel material exclusion criteria and to eliminate concerns about the safety related auxiliary feed system. Since no evidence of E/C was found in the Unit 1 auxiliary feed or charging systems, the scope of the Unit 2 inspections did not include these systems.

TABLE X-2a

PIPING SYSTEMS ELIMINATED FROM INSPECTION

	REASON FOR ELIMINATION			
SYSTEM	HIGH O_2	LOW TEMP	NOT CARBON STEEL	NOT H_2O
Fire Protection	X	X		
Domestic Water	X	X		
Fuel Oil				X
Waste Oil				X
Circ. Water	X	X		
Service Water	X	X		
Vacuum Priming	X	X		
Chilled Water	X	X		
Water Treatment	X	X		
Compressed Air				X
Primary Grade Water		X	X	
Turbine Lube Oil				X
Electro-Hydraulic Control				X
Bearing Cooling Water	X	X		
Secondary Sampling			X	
Reactor Coolant			X	
Residual Heat Removal			X	
* Chem. & Volume Control			X	
Boron Recovery			X	
Liquid Waste		X	X	
Decontamination			X	
Gaseous Waste			X	X

* This system was added to the scope of the recommended inspections for Unit 1 in order to validate the stainless steel material exclusion criteria.

TABLE X-2a (Cont'd)
PIPING SYSTEMS ELIMINATED FROM INSPECTION

	REASON FOR ELIMINATION			
SYSTEM	HIGH O_2	LOW TEMP	NOT CARBON STEEL	NOT H_2O
Radiation Monitoring				X
Spent Fuel Pit	X	X	X	
Reactor Cavity Purification	X	X	X	
Component Cooling	X	X		
Safety Injection		X	X	
Containment Spray		X	X	
Recirculation Spray		X	X	
Primary Sampling			X	
Containment Vacuum				X
Primary Vents & Drains			X	
Neutron Shield Cooling		X		
Condensate Polishing		X		
** Auxiliary Feed		X		

** This system was added to the scope of the recommended inspections for Unit 1 in order to eliminate concern over the functionability of the safety related auxiliary feed system.

TABLE X-2b

CARBON STEEL PIPING SUBSYSTEMS > 195°F
EXCLUDED FROM INSPECTION

Piping Subsystem	Reason for Inspection Exclusion
Main Steam	
- SHP line to atmosphere thru FE-MS100	Infrequent use
- Safety and reliefs	Infrequent use
- Decay heat release	Infrequent use
- Main steam dumps	Infrequent use
- Turbine stops to cylinder heating	MS superheated condition downstream of CV
- 1½" SRE line from reheater to crossunder (warm up line)	Infrequent use
Gland Seal	
- All	Low Velocity
Misc. Drains Secondary Plant	
- Equipment condensate drains (excluding traps)	Infrequent use
Boron Recovery	
- VA system	Not steam or water
Sampling System	
- Steam generator blowdown	Fluid downstream of coolers is less than 150°F. Carbon steel upstream of coolers is part of Blowdown System inspection program
Extraction Steam	
- 1½" and 2" S1ED thru S4ED	Infrequent use
Condensate	
- Feedwater heater relief lines	Infrequent use
Auxiliary Steam	
- 8"-SA-13-301	Infrequent use
- 4"-SA-8-301	Infrequent use
- 3"-SA-3-301	Infrequent use
- 4"-SA-29-30-301	Infrequent use
-ACA & AJA lines	Less than 100°F and at atm. or vac. press.
Steam Trap Lines	
- All	Not considered a major operational or safety hazard; to be considered by the ongoing Augmented Inspection Prog.

TABLE X-2b (Continued)

Piping Subsystem	Reason for Inspection Exclusion
Auxiliary Steam	
- Piping downstream of C.V.s	Low press. and not considered a major operational or safety hazard; to be considered by the on-going Augmented Inspection Program
- Heating steam piping	Same as above

TABLE X-3
INSPECTION POINT RATING SCHEME

1. Temperature Factor

	Temperature (^{o}F)	Rating
a.	265-320	5
b.	245-265 & 320-350	4
c.	230-245 & 350-380	3
d.	210-230 & 380-410	2
e.	195-210 & 410-440	1
f.	195 & 440	0

NOTE: For lines which operate at or near (within $5^{o}F$) saturation, add 3 to the rating given above.

2. Velocity Factor

	Velocity (FPS)	Rating
a.	25-30	5
b.	20-25	4
c.	15-20	3
d.	10-15	2
e.	5-10	1
f.	5	0

TABLE X-3 (Cont'd)

3. Geometry Factor

Geometry & Flow Disturbances	Rating
a. Control valve, tee (splitting), 280° bend	10
b. Check valve, globe valve, tee, flow orifices, components listed in c thru f below separated by between 3 and 10 pipe diameters	8
c. 90° bend, elbow, reducing elbow	6
d. Butterfly valve, instrument tap, reducer	4
e. Gate valves, welds in straight pipe	2
f. Straight pipe	0

NOTE: For close coupled geometry (components separated by less than 3 pipe diameters) add the indicated values of each of the components and assign the result to each of the components.

4. Use of Factors

For a given component, sum the three factors (temperature + velocity + geometry) above. The sum obtained can be used to identify the susceptibility to C/E and to establish an inspection priority, with a larger value indicating a greater susceptibility.

TABLE X - 4

ACCEPTANCE CATEGORIES

Acceptance Category	Criteria	Remarks
1. Immediate Replacement of Component	$Ta \leq Tm$ or $Ta \leq 0.100$	
2. Engineering Evaluation of Component	$Tm \leq Ta < Tacc/_{n=t_1}$	t_1 = time to next outage + 1/2 year. As a result of the engineering evaluation, each component in this category must be put in Category 1 or Category 3.
3. Potential Next	$Taac/_{n=t_1} < Ta < Tacc/_{n=t_2}$	t_2 = time to next 2 outages + 1/2 year. Component will be inspected at the next outage to verify the wear rate in order to confirm the need for replacement.
4. Each Outage	$Taac/_{n=t_2} \leq Ta < Tacc/_{n=t_3}$	t_3 = time to next 3 outages + 1 year. If no wear is determined by reinspection during the next three outages, put the component into Category 5.
5. Place Component in Station's Inspection Program	$Ta \geq Tacc/_{n=t_3}$	

TABLE X-5

* UNIT 1 - INSPECTION AND REPLACEMENT SUMMARY

Components Inspected		506
Total Number of Components Replaced		73
Components Replaced for Below Code Minimum	30	
Components Replace for Below Acceptance Criteria	17	
Components Replaced for Construction Convenience	26	
Components Designated for Potential Replacement at Next Refueling Outage		8

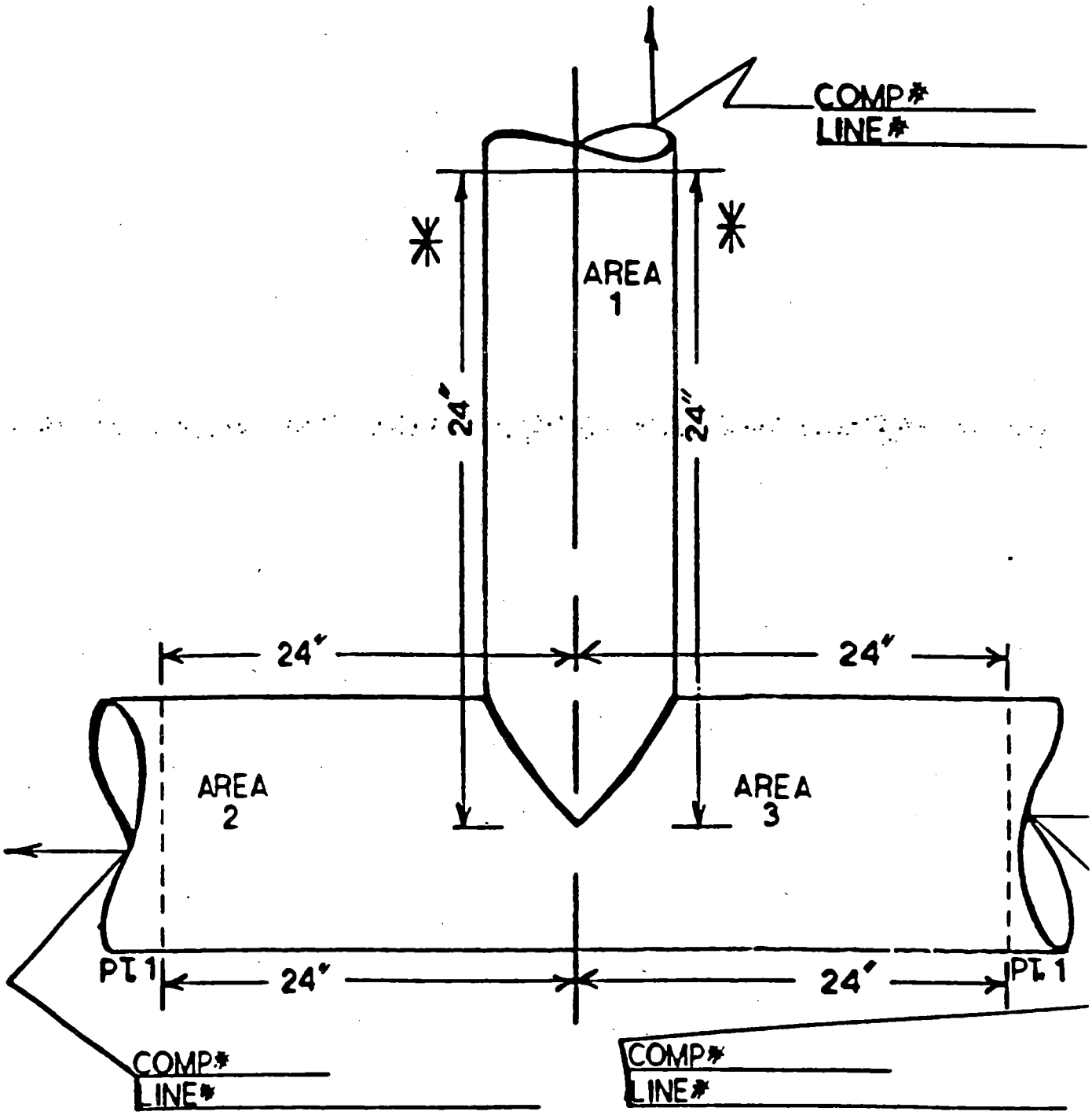
* Current as of March 20, 1987.

TABLE X-6

* UNIT 2 - INSPECTION AND REPLACEMENT SUMMARY

Components Inspected		317
Total Number of Components Replaced		81
Components Replaced for Below Code Minimum	31	
Components Replaced for Below Acceptance Criteria	29	
Components Replaced for Construction Convenience	29	
Components Designated for Potential Replacement at Next Refueling Outage		14
Components Designated for Replacement in approximately 6 months		4

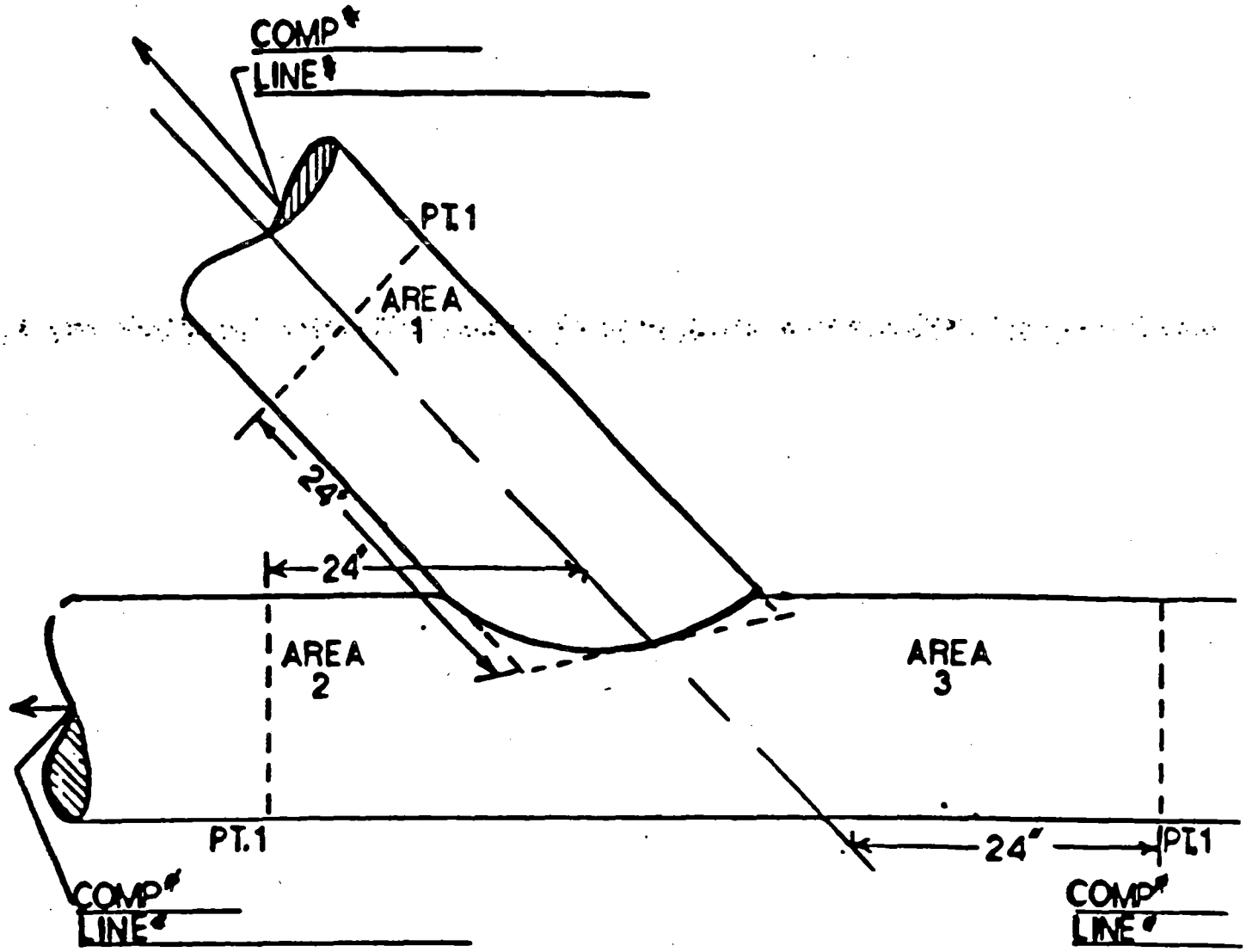
* Current as of March 20, 1987.



NOTE: READING TO BE TAKEN USING 2" x 4" MATRIX (360°)

* = REFERENCE START POINT TO BE DECIDED BY INSPECTOR. INSPECTOR IS TO PROVIDE DISCRIPTION AS TO WHAT REFERENCE WAS USED.

FIGURE X-1 - Tee Section Inspection Points



NOTE:

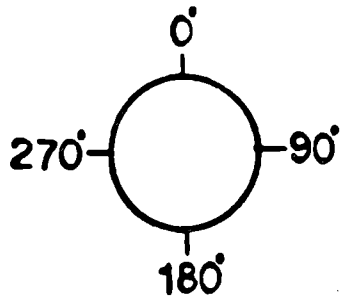
READING TO BE TAKEN USING 2"x4" MATRIX.

POINT ONE WILL BE TOP DEAD CENTER ON EXTERIOR WALL AS SHOWN ABOVE. IDENTIFICATION SHALL MOVE CLOCKWISE AS ONE FACES THE DIRECTION OF FLOW.

FIGURE X-4 - Lateral (45°) Inspection Points

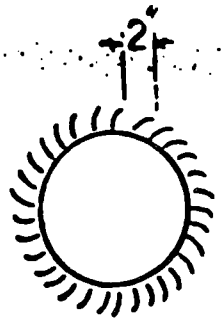
REQUESTED READINGS

Points #1 and #6



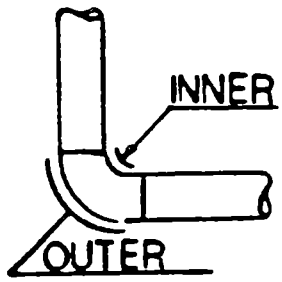
: Take reading one foot from the weld. Request four readings at 90° apart.

Points #2 and #7



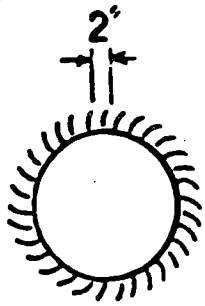
: Take reading two inches from the weld. Request reading every two inches (360°).

Points #3 and #5



: Take reading on inner and outer radius. Request scanning area and record lowest reading and highest reading.

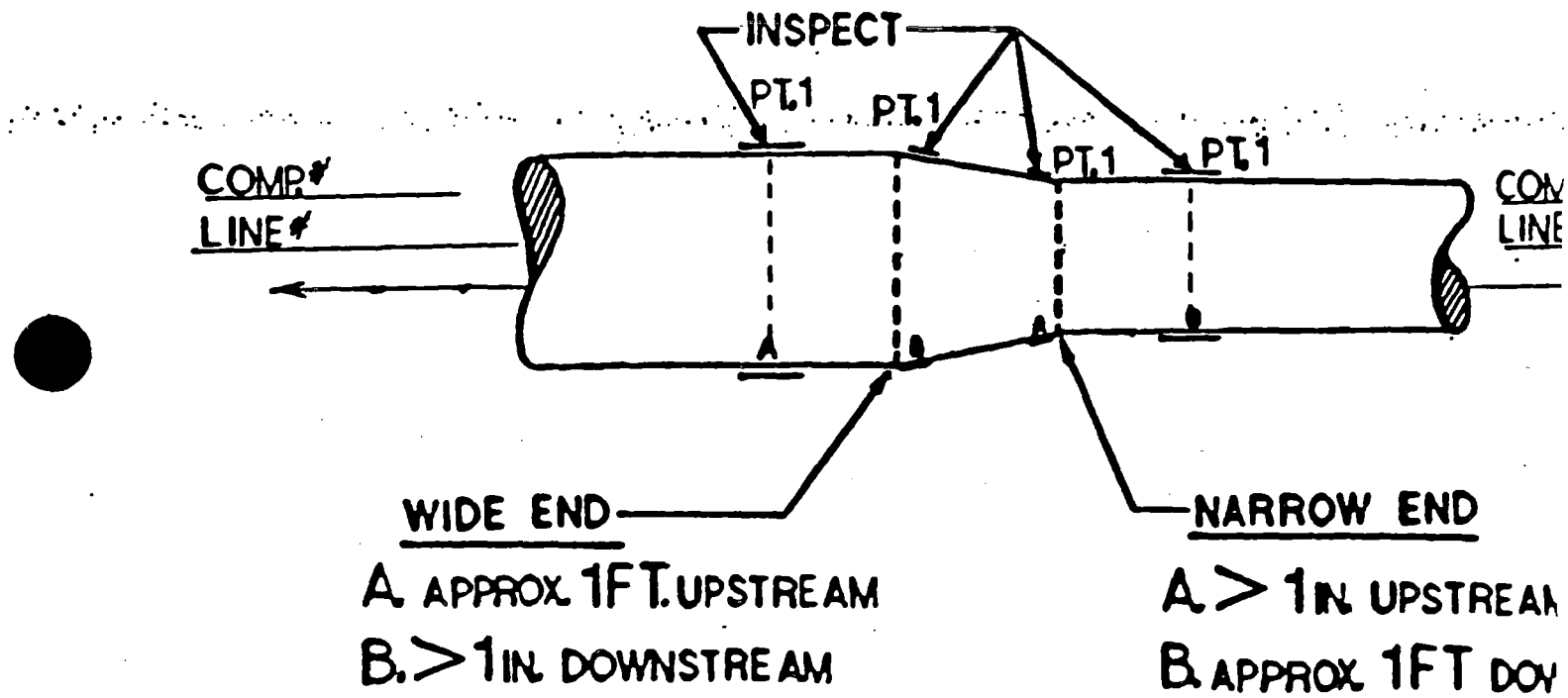
Points #4



: Take reading from inner radius center to out Request reading every two inches (360°).

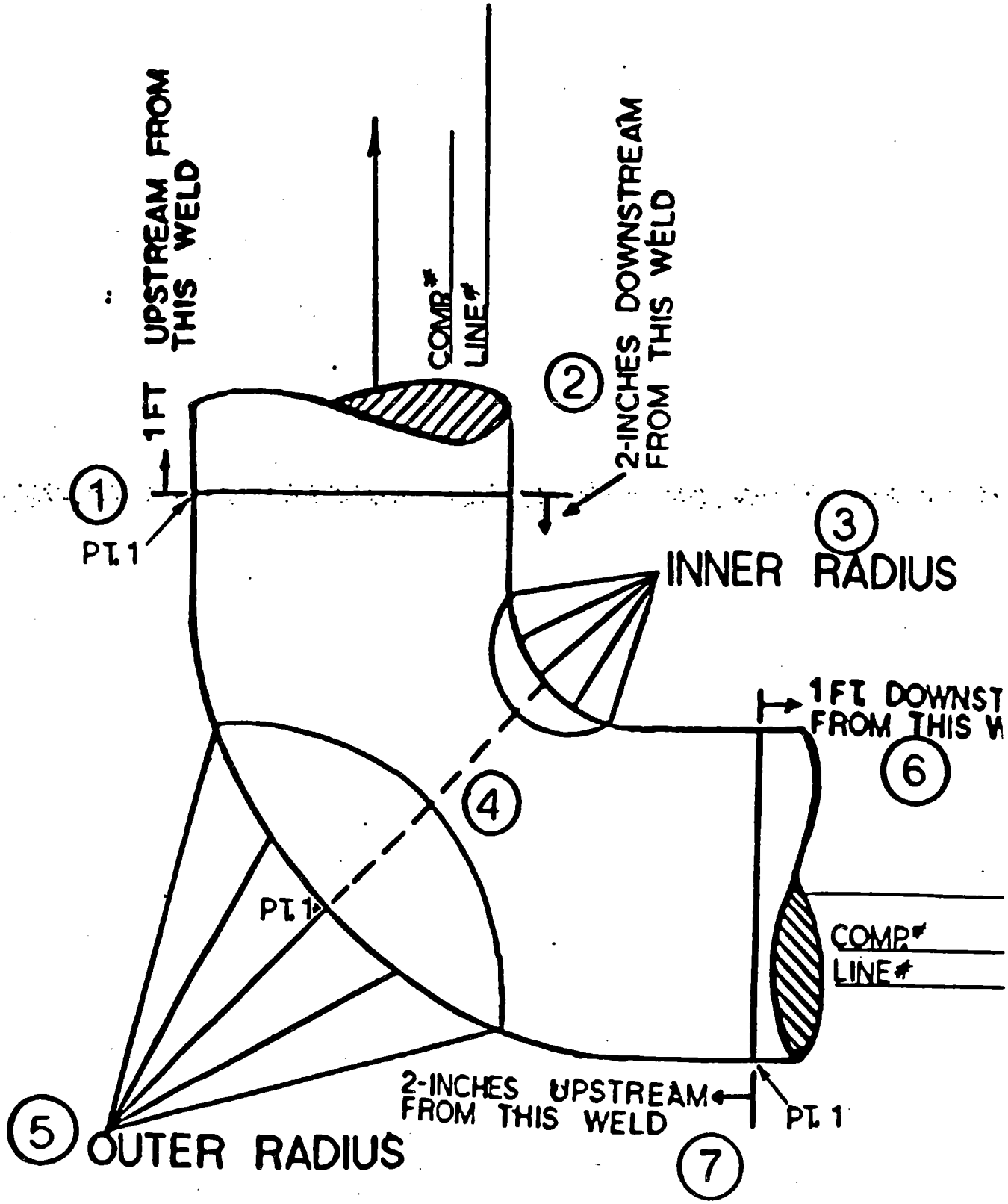
FIGURE X-5 - Pipe Inspection Requested Readings

REDUCER INSPECTION



NOTE: READINGS TO BE TAKEN EVERY 2 INCHES (360
POINT 1 WILL BE TOP DEAD CENTER WITH IDENTIFICATION MOVING CLOCKWISE AS ONE FACES THE DIRECTION OF FLOW.

FIGURE X-2 - Reducer Inspection Points



NOTE: "POINT 1" WILL BE OUTER RADIUS OF ELBOW. IDENTIFICATION MOVING CLOCKWISE AS ONE FACES DIRECTION OF FLOW.

FIGURE X-3 - 90° Elbow Inspection Points

B. Main Steam Trip Valve

1. Cause of Closure of Unit 2 MSTV

Based on the inspection and test findings (discussed in detail in Section b. below), the cause of the Unit 2 Main Steam Trip Valve (TV-MS-201C) closure was misalignment of the stop tube resulting from improper installation of the valve cover. The valve cover had been recently removed and reinstalled while performing maintenance to valve seating surfaces during the 1986 refueling outage. The stop tube is welded to the inner surface of the valve cover and is designed to physically limit valve disk travel to its normal span of 80 $\pm$ 2 degrees. Because of the misalignment, the valve disk was permitted to travel only 62 degrees in the open direction. However, even if the cover had been correctly aligned, incorrect installation of the radius levers on the rock shaft would have limited valve travel in the open direction to 75 degrees due to the actuating cylinder pistons prematurely topping out in their cylinders.

In either case, the valve disk would have been in an unstable position relative to the steam flow and easily susceptible to the closing forces presented by the steam flow through the valve. Taking into consideration the observed fluctuation in instrument air pressure just prior to the MSTV closure, it can be concluded with reasonable certainty that these combined conditions resulted in rapid closure of the valve by steam flow forces.

In addition to limiting valve travel in the open direction to 75 degrees, the incorrect installation of the radius levers on the rock shaft affected proper valve position limit switch operation. Limit switches are positioned such that they are operated by making and breaking contact with an actuator pin that is part of the valve actuator piston shaft to rock shaft linkage on the east actuating cylinder. The pin moves up and down as the trip valve opens and closes. Actuation of the upper limit switch provides open indication and actuation of the lower limit switch provides closed indication.

With the trip valve closed, radius lever mispositioning resulted in the actuator pin being positioned against the lower limit switch at a point higher than normal. Based on both field measurements and observations made during post accident trip valve cycling, the high positioning of the pin allowed the lower limit switch arm to be depressed just up to and not past its point of actuation. Additional manually induced travel of the limit switch arm of less than 1/32 inches resulted in switch actuation.

With the actuator pin higher than normal with the trip valve closed, pin travel when opening the trip valve to 62 degrees was more than enough to actuate the upper limit switch and thus indicate full valve opening when, in fact, the trip valve was not fully open.

The above described effect on limit switch operation resulted in full open position indicated in the control room prior to the spurious closure of TV-MS-201 and indication of intermediate valve position after the valve closed.

Given the close proximity of the arm on the lower limit switch to its actuating point with the trip valve closed, it is probable that actuation could occur given different trip valve variables (e.g. temperature, pressure, frictional forces, moisture content, etc.) The trip valve was, in fact, opened and closed several times between November 30, 1986 and December 2, 1986, during the early phases of plant startup following the 1986 refueling outage. During this cycling, the indication responded normally in the control room. Maintenance records indicate that limit switch adjustment was made after the trip valve was reassembled during the Unit 2 fall refueling outage. Limit switch adjustment on most valves after overhaul is not uncommon.

A listing of all maintenance performed on TV-MS-201C from time of overhaul to the time of spurious closure of the valve is detailed below.

Surry Work Order #	Job Description	Date Completed
041820	Overhauled trip valve. Made repair to seating surfaces.	10/28/86
045070	Repaired gasket seating surface on east stuffing box.	Worked concurrently with W.O. 041820.
045009	Adjusted close limit	11/5/86
046239	Injected Furmanite at east stuffing box gasket surface.	12/5/86

NOTE: Work Order 046251 was written as a result of a work request submitted on 11/29/86 due to failure of TV-MS-201C to open during hot stroking of the valve. No work done at that time to the work order. The trip valve stroked once water was drained from the valve and steam line by operations personnel.

2. Testing and Inspection of Unit 1 and 2 MSTVs

In an effort to determine the cause of the spurious closure of the Unit 2 'C" Main Steam Trip Valve, inspection and testing was performed using Special Test 2-ST-191 "Special Test to Inspect Operation of Main Steam Trip Valve TV-MS-201C". The results of that test, conducted December 15-19, 1986, are discussed below.

The test methodology consisted of leak testing the instrument air lines and actuator cylinders, stroke-testing the valve with the valve cover on, determining actual stroking distances of the actuating cylinders, stroke testing the valve with the valve cover off, and visually inspecting actuators, linkage, valve external components and valve internals for damage and proper installation.

The instrument air piping from the first isolation valve up to and including both actuating cylinders was pressurized using normal instrument air pressure. All components were soap-tested for leaks. The leaks identified were very minor and were judged to not affect proper cylinder operation.

With all valve components still assembled, the valve disk rotation was measured from the fully closed to the maximum attainable open position. Degree of rotation was measured at 62 degrees. Normal rotation from fully closed to fully open is 80 $\pm$ 2 degrees and is a

function of physical valve design. The position of the tube stop welded to the inner surface of the valve cover is such that it is designed to physically limit disk travel to 80 $\pm$ 2 degrees by coming in contact with the back of the valve disk at four contact points.

The east and west actuating cylinders were stroked with linkages attached, then unattached, to their full open and closed positions. With on exception, both cylinders completed full strokes. In that instance, the west cylinder failed to stroke to its fully inserted position. The piston was approximately 27/32 of an inch from bottoming. The inability of the west cylinder to travel to its fully inserted position is not considered significant since there was sufficient travel to permit full closure of the trip valve.

The valve was then cycled from its fully closed to maximum attainable open position with the valve cover off. Measured rotation was 75 degrees. Visual examination of the splined radius lever determined that the lever was offset by one spline tooth. This misalignment caused the cylinder pistons to top out with the valve only 75 degrees open.

Valve cover, stop, and all valve internals were visually inspected for damage and/or incorrect assembly. Using reference marks applied prior to removing the cover, it was determined that the cover had been previously installed misaligned by one bolt hole. This resulted in the stop tube being incorrectly positioned over the disk assembly and thereby limiting travel in the open direction to 62 degrees. This was verified by the existence of an impact mark on the edge of the stop tube near the center slot and a corresponding impact mark on the disk assembly. Other minor discrepancies were noted during the visual inspection but were judged not to affect proper valve operation.

3. Revision of Maintenance Procedure and Other Actions

As a result of this inspection, maintenance procedure MMP-C-MS-002 has been revised to ensure correct trip valve disassembly, inspection, and reassembly. The remaining Unit 2 MSTVs will be tested and inspected for proper operation and condition; TV-MS-201C will be further disassembled and inspected to ensure no damage to other valve parts. The actuating cylinders will be rebuilt. The Unit 1 MSTVs were also tested to ensure proper operation. Based on these test results, and the Unit 2 inspection results, a decision has been made to inspect Unit 1 valve internals.

C. Main Feed Pump Discharge Check Valve

1. Cause of Failure of Unit 2 'A' Main Feed Pump Discharge Check Valve

The Unit 2 'A' Main Feed Pump check valve (2-FW-127) was inspected after the event and found to have a missing hinge pin and the disc/seat assembly had shifted out of position. The consequence of this condition is that the valve could not have performed its design function of preventing reverse water flow. This condition can be attributed to the design of the valve in conjunction with corrosion/erosion (C/E).

The left side hinge pin, one of two pins which form the hinge for the valve disc, was found to be missing. Valve design is such that each hinge pin is held in place by a set screw which engages a groove machined in the hinge pin. The set screws are tack welded to keep them in place. This inspection revealed that the left side set screw was eroded, allowing it to back out and the hinge pin to dislodge. Since the hinge pin was not found in the vicinity of the valve, it has probably been missing for some period of time. With only one hinge pin the disc will still seat, although the probability of malfunction increases.

The disc/seat assembly consists of the disc, hinge and seat. This assembly was found to have shifted inside the valve body due to failure of the two clamp devices which hold it in place.

The clamp assembly consists of a lockplate with a tab welded on one side and a securing bolt. This lockplate is positioned with the tab resting on the valve body and the other end of the lockplate on the disc/seat assembly. The bolt is torqued into the valve body securing the disc/seat assembly and then the bolt is lockwired in place. The inspection revealed the tabs of both lockplates were eroded, which allowed movement of the lockplates and the disc/seat assembly. The lockwires were also missing due to either movement of the lockplate or C/E. The disc/seat assembly was found to have shifted and jammed such that there was a two inch gap between the valve body and the bottom of the disc/seat assembly. This displacement would prevent the check valve from stopping reversed water flow.

This check valve performed satisfactorily during Unit 2 startup on 12/2/86 when the "B" Main Feed Pump was running with the "A" pump shut down. If the disc/seat assembly had been displaced during the startup, there would have been significant backflow through the "A" Main Feed Pump which would have been discovered. The "A" Main Feed Pump was placed into operation on 12/5/86 during the normal plant startup sequence. Therefore, the disc/seat assembly displacement probably occurred between pump startup and 12/9/86 or as a result of the feed line rupture.

A maintenance history review indicated that this valve had not been opened in at least six years and may not have been opened since installation. The preventive maintenance inspection of this check valve scheduled for 1984 was cancelled as a result of an inspection on a Unit 1 Main Feed Pump discharge check valve which showed the valve to be in good condition.

2. Inspection of Unit 1 & 2 Main Feed Pump Check Valves

All of the Main Feed Pump discharge check valves have been inspected as a result of the Unit 2 "A" Main Feed Pump check valve inspection. The Unit 2 "B" Main Feed Pump check valve inspection (2-FW-112) found loose bolts for both clamp assemblies and the lockwires for these bolts were missing. The lockplates were in fair condition with some erosion. No shifting of the disc/seat assembly was noted.

The Unit 1 "B" Main Feed Pump check valve (1-FW-112) was found to have loose bolts for both clamp assemblies and the lockwires for these bolts were missing. The lockplates were in poor condition with extensive erosion. The disc/seat assembly had not shifted in the valve body. The left side hinge pin was missing but the set screw was still tack welded in place. The set screw end which engages the slot in the hinge pin was deteriorated. In this condition the valve would have performed its design function.

The Unit 1 "A" Main Feed check valve (1-FW-127) had been overhauled in May of 1986 and the current inspection showed it to be in excellent shape with no defects.

3. Corrective Action for Main Feed Pump Check Valves

Corrective action for the Main Feed Pump discharge check valves will consist of modification to the hinge pins and their locking devices and elimination of the clamp assembly. New hinge pins will be installed that are secured in place by a lock pin which is welded in place. The lockpin will project through a hole in the hinge pin preventing rotation inside that half of the hinge. This design will eliminate wear on the locking pin and coupled with the securing weld should minimize the C/E problem. The clamp assembly will be eliminated by welding the disc/seat assembly onto the valve body. These modifications are in accordance with Crane Valve Services recommendations.

These modifications will be performed prior to returning the units to service, with the exception of the disc/seat assembly change for the Unit 1 valves. Due to a material unavailability from the manufacturer, these assemblies will be replaced at the next scheduled outage of sufficient duration when the material is available or the next refueling outage.

The Main Feed Pump Discharge check valves will be periodically inspected in accordance with the Manufacturer's recommendations.

D. Fire Protection Systems

1. Fire Protection System Evaluation

a. Halon System Actuation

The system was inspected to evaluate the reason for the inadvertent system actuation. The Control Panels for both units (1-FPH-CHI) are mounted on the Unit 1 side of the wall between the Unit 1 and Unit 2 Turbine Building (the "9 line" wall) at elevation 9 feet, 6 inches.

Shortly after the feedwater pump suction linebreak, both zones of the system were actuated when water entered the control panel through an open condulet and shorted out circuits in the panel. Halon was discharged to the Unit 1 and 2 Emergency Switchgear Rooms. The automatic fire dampers 4, 8, 15, 21, and 22 were inspected and found to be in the proper closed position. Based on these findings, when the Halon system was actuated, it functioned as designed.

b. CO_2 System Actuation

Units 1 and 2 Cable Tray Room CO_2 systems were inspected to evaluate the reason for system actuation. The CO_2 panels are located on the Unit 2 side of the "9 line" wall on the 45 foot elevation of the Turbine Building. When opened, water was found inside the panel boxes with blackening of contacts on several control relays. Conduits leave the top of the panels and run to the edge of a cable tray directly above the cabinets. The conduits are not sealed and make a 90° bend off the wall where the wire

exits the conduit and enters the cable tray. A fire protection sprinkler head is located approximately 10 feet from, and in-line with, the opening to the conduit. Two other sprinkler heads are located above the cable tray. The in-line sprinkler head and one other sprinkler head, closer and to the right of the control panels, were actuated due to steam and hot water.

The Unit 1 Cable Tray Room contained an excessive amount of CO_2 after the incident due to shorting of either the timer or hold relay in the Unit 1 control panel. The CO_2 bulk storage tank was completely emptied as a result. In addition, automatic fire dampers (Dampers 27A, 27, 28, and 29) were inspected and found in the proper closed position. Based on these findings, once the system was actuated it functioned as designed except for the excess discharge to the Unit 1 Cable Tray Room. During inspection of the stairwell behind the MCR, it was noted that no warning mechanism has been provided to alert someone entering the stairwell that a CO_2 discharge has taken place.

c. Turbine Building Sprinkler System

Sixty-two protection sprinkler heads actuated in the Unit 2 Turbine Building due to the steam and hot water. This added to the water in the Turbine Building basement. Water from the sprinklers outside the Unit 2 Cable Tray Room apparently flowed under the door into the room.

The Turbine Building sump effectively handled the water in the Turbine Building basement. The water in the Unit 2 Cable Tray Room

was believed to be the source of water dripping behind the Unit 2 Vertical Control Board in the Main Control Board in the Main Control Room (MCR). The water apparently leaked down around the foam fire seals in floor penetrations to the MCR.

2. Actions To Be Taken

Penetrations from the Emergency Switchgear rooms have bee inspected and sealed where necessary to mitigate Halon in the MCR from future discharges. A Station Deviation and engineering Work Request (EWR) have been written to identify and evaluate the control room emergency air bottle system discharge piping. The 62 Turbine Building sprinkler heads have been replaced and the Turbine Building sprinkler system restored to operable status.

The following additional actions will be taken or evaluated.

1) The CO_2 and Halon systems will be returned to full service or fire watches will be maintained.
2) CO_2 and Halon system related conduit and control cabinets will be inspected and sealed as necessary and effectively shielded from overhead water sources, e.g. fire protection sprinkler heads.
3) The penetrations in the ceiling of the MCR behind the Unit 2 Vertical board will be inspected and replaced or modified to insure an adequate seal for fire and water.
4) Procedures will be developed for searching and ventilating areas protected by Halon or CO_2.

5) Visual warning devices are being evaluated for installation in areas protected by CO_2.

6) Wintergreen odorizers will be added to the piping supplying CO_2 to each area.

E. Security Plan

1. Security Plan Implementation

Security Plan Implementation was effective. One area of concern was noted. Specifically, a vehicle entering the station's protected area in support of the emergency was not given expedited clearance by security personnel.

An operator was in the stairwell behind the MCR, when the cardreaders failed preventing access to the MCR or the Emergency Switchgear Room. Normally personnel could exit through the Unit 2 Cable Tray Room. However, knowledge that the CO_2 system had discharged discouraged use of that exit. Apparently, some CO_2 leaked around the fire door from the Cable Tray Room into the stairwell causing the operator to experience difficulty breathing. He exited the stairwell into the MCR when an operator heard him knocking on the door and opened it.

2. Actions To Be Taken

a. The Security Plan allows for relaxing Security requirements during emergencies. By December 11, 1986, Security personnel had been made aware of the requirements for permitting expedited access. Specific training modules will be upgraded to include instruction on expedited access requirements.

b. Override switches will be evaluated for all areas where access is granted by a cardreader.

F. Emergency Plan

1. Emergency Plan Implementation

The Surry Power Station Emergency Plan (SEP) was activated at 1430 on December 9, 1986, in accordance with Emergency Plan Implementing Procedure 1.01, Emergency Manager Controlling Procedure, TAB G, Loss of Secondary Coolant. A Notification of Unusual Event was declared due to a major line break in the secondary system as described by the SEP. Although no specific Emergency Action Level indication for declaring an Alert was met, the Station Emergency Manager opted to declare an Alert to mobilize Station, Corporate and Off-site resources, establish lines of communications, and facilitate personnel accountability. The Alert was declared at 1440 and was terminated at 1623.

Response to the emergency was in all cases professional. Assistance rendered to injured persons was skilled and timely. Emergency facilities were manned quickly and accountability was completed promptly. Successful implementation of the Emergency Plan was challenged by the communications difficulties.

2. Communication Difficulties

Communications with the NRC Operations Center was initiated by the NRC rather than plant personnel as prescribed by procedure well before the time frame for reporting had expired. This complicated initial data collection for the report to the NRC and contributed to the delays experienced making timely reports to the State. The communicator's mobility was hindered by having to actively maintain an open line to NRC.

Communications with the State and surrounding localities within 10 miles of the plant were made using the Insta-Phones in Control Room and the Technical Support Center (TSC). Reception by the localities was reported as being poor when messages were sent from the TSC. Because of this the Communicator traveled back and forth between the TSC and the Control Room.

Greater attention to the timely transmission of reports to the State and local governments is required. Initial reports are required within fifteen minutes following declaration of an event and follow-up reports are required every thirty minutes or whenever the status of any notification item changes. Three reports were sent. The initial report of the Notification of Unusual Event was sent at 1440. The follow-up which reported escalation to Alert was sent at 1532 and the report of the event's termination was sent at 1624. Communications with local governments was limited to the reports sent over the Insta-Phone and specific requests for assistance, i.e, Surry and Isle of Wight Volunteer Rescue Squads. Media personnel arrived at the station to obtain first-hand information rather than reporting to the Local Media Center in Surry which was established to handle their inquires.

3. Action To Be Taken

Communications hardware has been checked and found to be operable. The following actions will also be taken to improve Emergency Plan Implementation:

a) Review the process for initiating communications between the Control Room/TSC and the NRC Operations Center.

b) Evaluate the possibility of obtaining a radio headset for use by the Communicator to facilitate data collection while actively maintaining an open line with the NRC.

c) A Multifunction Media Center will be built adjacent to the site to facilitate and improve media communications during an emergency.

G. Surry Power Station Startup Plan

1. Problem Identification

Subsequent to the December 9, 1986 pipe rupture in Unit 2 at the Surry Power Station, technical review committees were formed. Each of these committees was tasked with a specific aspect of identifying and evaluation events that occurred during and immediately following the pipe rupture incident. These efforts were in addition to the normal post trip review required by station procedures.

The problems identified by the technical committees have been compiled into a documentation package for each of the Surry Units. The items have been uniquely numbered and entered into a common tracking system. The progress on each item provides a means to maintain a current status of each item and to determine how each one is progressing in the disposition process. It will also provide a summary of overall progress toward unit startup.

2. Methods of Dispositioning

The current work control process will be utilized which consists of: (1) Work Order System (Maintenance), (2) Engineering Work Requests or Design Changes (Design Control). This process already has requirements for diverse reviews such as Supervisor, Q.A., and engineering as

appropriate. Deviations to procedures are reviewed by the Station Nuclear Safety and Operating Committee (SNSOC) as required by Technical Specification.

Post maintenance or modification testing is required by the normal work process which includes appropriate Technical Specification surveillance and testing. Although these processes are normally considered adequate, Virginia Power management is committed to ensuring proper and thorough review of the resolution of items identified during the Surry pipe rupture incident.

3. Augmented Review Measures

a. Station Employee Operational Review Task Group

The SNSOC chairman has appointed a three person employee task group comprised of personnel with SRO, STA, and investigative techniques background. The task group will review the event and startup procedures and develop recommendations for special testing, surveillance, and startup procedure modifications, if any, which may be required prior to each units startup.

This employee task group will then present their findings and recommendations to SNSOC.

b. Independent Review

The Vice President of Nuclear Operations has tasked the Independent Review Section of the Safety Evaluation and Control Department to perform a special independent evaluation to assure that the problems identified in Table X-7 and X-8 have been completed prior to startup.

The Independent Review Section will use the problem tracking system described above to review the startup of each item.

The task group will review the event and startup procedures to determine what additional, if any, testing, surveillance, and startup procedure modifications are required for each unit startup.

This task group will then present their findings and recommendations to SNSOC.

c. Station Nuclear Safety and Operations Committee (SNSOC)

The SNSOC will review with the Independent Review Section the status of the items in the tracking system. The SNSOC will also review the overall startup plan for the units and the findings and recommendations of the Employee Operational Review Task Group.

This will be an iterative process until the SNSOC is satisfied that the items have been appropriately dispositioned and the units are ready to startup.

The SNSOC chairman will present the committees recommendations to a Management Review Team.

d. Management Review and Startup

The Management Review Team will consist of the Vice President of Nuclear Operations, the Manager of Operations and Maintenance Support, the Manager of Nuclear Programs and Licensing, and the Manager of the Surry Power Station.

When the Management Review Team is satisfied that safe unit operation may resume, a discussion will be held with the Nuclear Regulatory Commission's Senior Resident for Surry. Only after concurrence is received from the NRC will the startup commence.

4. Surry Unit 1 Startup Reviews

Prior to restart of Surry 1, the augmented review process described in Section X.H.3 will be performed to determine that the problems identified in Table X-7 have been satisfactorily dispositioned.

5. Surry Unit 2 Startup Reviews

Prior to restart of Surry Unit 2, the augmented review process described in Section X.H.3 will be performed to determine that the problems identified in Table X-8 have been satisfactorily dispositioned.

H. Long Term Considerations

A number of items have been recognized as requiring long term resolutions. Long term is defined as sometime after startup. The items identified as "Long Term Concerns" will receive extensive review and will be placed on our Commitment Tracking System (CTS). Examples of these items are:

- The evaluation of our chemistry control program in particular the chemicals used.

- The inspection of high alloy piping systems as part of our ASME Section XI inspection program to provide additional confirmation that corrosion/ erosion is not occurring. This inspection will be a zero degree ultrasonic examination of the pipe wall on either side of designated welds. The welds will be selected with the criteria developed for areas susceptible to corrosion/erosion.
- The possibility of further changes to piping systems including geometry and/or changes in material.
- The evaluation of the Emergency Plan for possible enhancements.

TABLE X-7
STARTUP REVIEWS
SURRY UNIT NO. 1

Item No.	Responsible Individuals	Problem	Action	Status
1		MSTV Operability	Evaluate/Repair	
2		Sprinkler system actuated	Evaluate	
3		Door card reader malfunction	Evaluate/Modify	
4		NRC OPS center called Control Room	Evaluate	
5		H2O flowing in Cable Tray area	Evaluate/Modify	
6		MCR/U-2 Turbine Building door blocked open	Evaluate	
7		CO2 in MCR	Evaluate/Modify	
8		Halon in MCR	Evaluate/Modify	
9		CO2 in #1 Mechnical Equipment Room	Evaluate/Modify	
10		H2O in Halon Control Panel/ESGR ESGR Halon actuated	Inspect/Clean/Test	
11		H2O in CO 2 Control Panel/Cable spread area CO2 actuated	Inspect/Clean/Test	
12		Use of all CO 2 (Low pressure)	Evaluate/Repair	
13		Cable Tray Room Electrical Pentrations into MCR	Evaluate/Replace Seals	

TABLE X-7
STARTUP REVIEWS
SURRY UNIT NO. 1

Item No.	Responsible Individuals	Problem	Action	Status
14		Lack of procedure for Maintaining Control Room Enviroment	Evaluate/Write Procedure	
15		MFP discharge check valves	Inspect/Repair	
16		Inspection of selected piping	Inspect/Replace	
17		MS & FW piping inside containment inspection	Inspect	
18		Emergency Plan	Evaluate/Modify	
19		MCR Pressure test	Perform	
20		Security radio repeater frozen	Evaluate	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
1		Packing leak 2A LP HTR DR pump	Evaluate	
2		3A FW HTR relief Leaking	Evaluate	
3		RCP Under frequency Relays	Repair	
4		MSTV Operability	Evaluate/Repair	
5		Rod M-10 Indication	Evaluate/Repair	
6		No disagreement light 'A' MFP	Evaluate	
7		Some lighting circuits lost	Evaluate	
8		MCC 2A1-2 & 2B1-3 grounds	Inspect/Repair	
9		High indication of "A" MFP suction	Evaluate/Repair	
10		MFP discharge check valve	Inspect/Repair	
11		HP Htr DR PP trip circuit	Evaluate	
12		FCV-CN-207 auto control circuit	Evaluate/Repair	
13		Analysis of failed pipe	Analyze	
14		Inspection of selected piping	Inspect/Replace	
15		Small valves in lube oil & seal cooling water bent stems	Repair	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
16		Insulation damage of adjacent pipes	Remove/Replace	
17		H-62 damage	Replace	
18		H-62 structural support damage	Replace	
19		Upstream supports	Inspect	
20		H-61 loose nuts	Tighten	
21		H-61 adjustment	Adjust	
22		H-93,H-111 support steel distortion	Evaluate	
23		Platform curb plate, handrails damage	Replace	
24		MCC 2A1	Clean/Test	
25		Purple cable tray, C-el 31'6" Section 289	Repair/Replace	
26		Orange cable tray, C4-el 29'6" Section 289	Repair/Replace	
27		Black cable tray, A-el 30'6" Section 289	Repair/Replace	
28		Motors, north half of U-2 (Turbine Building), on or below Mezzine	Test	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
29		Vertical Cable tray 2C5PH1-0	Replace	
30		From C Tray El. 31 to SOV-FW250B, north of B pump. Conduit support and conduit bent	Straighten	
31		SOV-FW250B, north of B pump to local junction box. Flexible conduit broken and included wires damaged	Replace	
32		SOV-FW250B, north of B pump to local junction box. Flexible conduit broken and included wires damaged	Replace	
33		From B tray El. 31 junction box at east end of B pump. Conduit and conduit supports out of position	Repair	
34		From vertical conduit to bearing temp. probes on east end of B pump. Conduit and conduit supports out of position.	Repair	
35		From B tray El. 31 to south side of B pump. Conduit and supports bent, 'T' condulet broken at 31 ft. El.	Replace	
36		From C4 tray El. 31 north of A pump to RTD 213A on B pump suction line.	Repair/Replace	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
		Conduit broken above A pump. Supports are damaged.		
37		From conduit at El. 31 to RTD on A pump suction line. Conduit is gone. Conduit support is damaged.	Repair/Replace	
38		Lighting under C tray El. 31 over A and B pump. Conduit and included wire is damaged.	Replace	
39		From TB-PS-CN217 A/B north of A pump to CN217A. Conduit broken and supports are damaged.	Replace	
40		From TB-PS-CN217 A/B north of A pump to CN217B. Conduit bent and supports are damaged.	Repair/Replace	
41		Damaged lighting	Repair/Replace	
42		SOV FW250B, north of B pump. Tubing is crimped.	Replace	
43		SOV FW250B, north of B pump. Tubing is crimped.	Replace	
44		F1CFW250BL from north of A pump up to El. 31 then south above pumps. Support and tubing above pumps are damaged.	Repair/Replace	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
45		F1CFW250BH from north of A pump up to El. 31 then south above pumps. Support and tubing above pumps are damaged.	Repair/Replace	
46		F1CFW250AH, AL, BH and BL from north of A pump up to. Support under Y line is damaged.	Repair/Replace	
47		LCV-SD-240B and D El. 31 ft. north of A pump. Tubing is crimped.	Replace	
48		LCV-SD-240A and C El. 31 ft. north of A pump up to El. 31 then west under Y line steel. Tubing is damaged.	Repair/Replace	
49		Instrument rack north of "A" feedwater pump 1. PT-CN-250A 2. PT-CN-250B 3. PS-FW-250A (including air supply gage) 4. PS-FW-250A-1 5. PS-FW-250B (including air supply gage) 6. PS-FW-250B-1 7. PT-FIC-FW250A 8. PT-FIC-FW250B	Inspect/Repair/ Replace/Test	
50		"A" feedwater pump recirculation valve station 1. SOV-FW-250A	Inspect/Repair/ Replace/Test	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
		2. Accumulator tank and support 3. Associated junction box		
51		"B" feedwater pump recirculation valve station 1. Limit switches and associated flex conduit 2. Accumulator tank and support 3. SOV-FW-250B (including crimped tubing)	Inspect/Repair/ Replace/Test	
52		"A" feedwater pump local instrumentation 1. 0-30 psi oil pressure gauge (1/4 NPT) 2. 0-250 °F dial temp. indicator- oil cooler 3. 0-250 °F dial temp. indicator- (in-line with pressure switches) 4. 1/4" sensing line and fitting (1/2"x1/4" reducer oil pressure line on "T" rack - left side of pump) 5. 1/4" oil return line to reservoir (stainless steel) 6. 0-3000 psi pressure gauge (1/2" NPT) 7. All pressure switches on the pump skid	Inspect/Repair/ Replace/Test	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
53		"B" feedwater pump instrumentation 1. 0-30 psi oil pressure gauge (1/4" NPT) 2. 0-3000 psi pressure gauge (1/2" NPT) 3. 0-250 °F dial temp. indicator - oil cooler 4. 0-250 °F temperature indicator (in-line with pressure switches) 5. All pressure switches on the pump skid	Inspect/Repair Replace/Test	
54		Instruments mounted on I beam adjacent to "B" feedwater pump 1. PS-CN-202B 2. PS-CN-212B	Inspect/Repair/ Replace/Test	
55		Instruments on transmitter rack 274. 1. FT-SD-202A 2. FT-SD-202B 3. FT-SD-203 4. PT-MS-2468 5. PT-MS-208A 6. PT-MS-202	Inspect/Repair/ Replace/Test	
56		RTD-SD-21 (flex conduit from RTD to cable tray has been damaged).	Repair/Replace	
57		Feedwater heater 1A and 1B inlet temperature gages are pegged high and have water in them.	Replace	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
58		Valve positions on FCV-SD-240D has been damaged.	Repair/Replace	
59		Positioners for FCV-SD-204A, B, C, and D were in the blowdown path of the ruptured 18 inch line.	Repair/Replace	
60		2-FW-P-1A	Inspect	
61		2-CN-135	Operate	
62		Feedwater Heater tubes	Hydro	
63		S/G Blowdown coolers	Observation during startup	
64		Pipe support hardware H-60, H-59, H-57	Inspect	
65		MS & FW piping inside containment inspection	Inspect	
66		Cable in tray C4 and A section 289	Evaluate	
67		'A' MFP motors	Inspect/Clean/Test	
68		'B' MFP motors	Inspect/Clean/Test	
69		'B' MFP motor connection box/screens	Repair	

TABLE X-8
STARTUP REVIEWS
SURRY UNIT NO. 2

Item No.	Responsible Individuals	Problem	Action	Status
70		Cable discoloration	Evaluate	
71		2-VS-F-42 sprayed with H2O	Inspect/Test	