ARKANSAS POWER & LIGHT COMPANY
POST OFFICE BOX 551 LITTLE ROCK, ARKANSAS 72203 (501) 371-4000

May 7, 1985

ØCANØ585Ø5

Director of Nuclear Reactor Regulation
ATTN: Mr. J. F. Stolz, Chief
Operating Reactors Branch #4
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Director of Nuclear Reactor Regulation
ATTN: Mr. James R. Miller, Chief
Operating Reactors Branch #3
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, DC 20555

SUBJECT: Arkansas Nuclear One - Units 1 & 2
Docket Nos. 50-313 and 50-368
License Nos. DPR-51 and NPF-6
NUREG-0737, Item II.D.1, Performance
Testing of Relief and Safety Valves

Gentlemen:

NUREG-0737, Item II.D.1, required testing of pressurizer safety and relief valves to establish their operability under expected operating conditions for design-basis transients and accidents.

The required testing was conducted during 1980 and 1981 by the Electric Power Research Institute. The Nuclear Regulatory Commission and Arkansas Power & Light Company were participants in the testing program. The applicability of the data to Arkansas Nuclear One - Unit 1 and 2 was discussed in our letters of July 28, 1982, (1CANØ78211 and 2CANØ78211). An evaluation of the plant-specific discharge piping was forwarded by our letter of November 30, 1982 (ØCAN118225).

A046
1/21

In your letter dated December 18, 1984, (ØCAN128414) you requested additional information relative to the EPRI testing program and AP&L's submittals. The questions asked were detailed and comprehensive. We requested 120 days in which to prepare the attached response (ØCANØ1851Ø). In that time, with the assistance of the AP&L personnel who originally monitored the EPRI program and with the detailed work done by our consultants, we have assembled a complete response. Although this submittal is extensive, it achieves far less as a substantive contribution to the plant-specific data available to the NRC than as an exhaustive effort to organize the material into a format more compatible with the approach which the NRC is now taking towards this review. This response supports an NRC finding that we have demonstrated the ability of the reactor coolant system safety and relief valves to function under design basis transients and accidents, thereby completing Item II.D.1 for ANO Units I and II.

Very truly yours,

Dan Howard

for J. Ted Enos
Manager, Licensing

JTE:MGB:ds

ARKANSAS POWER & LIGHT COMPANY

RESPONSE TO
REQUEST FOR ADDITIONAL INFORMATION
TMI ACTION NUREG-0737 (II.D.1)
FOR
ARKANSAS NUCLEAR ONE
UNITS 1 AND 2

APRIL 1984

ATTACHMENT
Letter Number ØCANØ585Ø5
May 7, 1985

CONTENTS

PART I. GENERAL INTRODUCTION

A. Introduction 6
B. Plant Specific Safety and Relief Valve Systems 7

PART II. DEMONSTRATION OF SAFETY/RELIEF VALVE OPERABILITY

A. Introduction 10
B. ANO Unit 1 12
C. ANO Unit 2 50

PART III. SAFETY/RELIEF VALVE PIPING SYSTEM

A. Introduction 122
B. ANO Unit 1 123
C. ANO Unit 2 137

PART I.

GENERAL INTRODUCTION

A. INTRODUCTION

1. Background

In the aftermath of the Three Mile Island (TMI) accident, the Nuclear Regulatory Commission issued requirements that utilities operating and constructing pressurized water reactor (PWR) power plants demonstrate the operability of pressurizer safety and relief valves and the structural adequacy of the discharge piping and supports. These requirements were promulgated in NUREG-0578 and NUREG-0660, and further clarified in NUREG-0737. At the request of utilities with PWRs, the Electric Power Research Institute (EPRI) developed and implemented a generic test program for pressurizer power operated relief valves and safety valves which was accomplished between 1980 and 1982. Safety and relief valves representative of those utilized in participating PWRs were tested under the full range of test conditions.

2. NUREG Requirements

NUREG-0737 Item II.D.1 requires PWR licensees to conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

3. The EPRI PWR Safety and Relief Valve Test Program

The objective of the EPRI PWR Safety and Relief Valve Test Program was to perform full scale operability tests on a set of primary system relief and safety valves representative of those utilized

in PWRs and gather discharge piping data to permit the benchmarking of discharge piping analysis methods. The test conditions were selected to be representative of those challenging participating PWRs.

The NRC recognized in NUREG-0737 that it would be feasible to select a limited but fully representative set of valves for test purposes. In the event that the testing enveloped the licensee's valve, the licensee is to submit data showing the correlation of test conditions and piping configurations to the generic test.

The relief valve tests were performed at the Marshall Steam Station test facility, Terrell, North Carolina (owned and operated by Duke Power Company) and the test facility located at Wyle Laboratories, Norco, California. All safety valve tests were conducted at the test facility located at Combustion Engineering, Windsor, Connecticut. Valve performance testing was completed in December, 1981.

B. PLANT SPECIFIC SAFETY AND RELIEF VALVE SYSTEMS

1. Unit 1

ANO-Unit 1 (ANO-1) is a Babcock & Wilcox PWR rated at 836 MW Net. It is a 177-FA design plant. It went commercial in December 1974.

The overpressure protection for the reactor coolant system is provided by two Dresser 31759A closed bonnet, 3" by 6", spring-loaded, self-actuated safety valves. Each valve has a bore diameter of 2.062 in and a bore area of 3.341 in^2. The calculated rated flow for each safety valve is 108.61 lbm/sec. Each valve is flange mounted on its own 3" ID x 21" long pressurizer nozzle. Each valve discharges into a six-inch schedule 40 pipe which separately run to a common header immediately upstream of the quench tank.

The ANO-1 Pressurizer is equipped with a Dresser 31533-VX-30-1 Electromatic PORV. It has a bolted bonnet with a 2½"-2500 lb inlet flange and a 4"-600 lb outlet flange. The bore diameter is 1.094 in. The calculated rated flow for the PORV is 30.54 lbm/sec at 2500 psig. Prior to the EPRI testing this valve was modified to Dresser's dash 2 design. The dash 2 modifications changed the Tube Insert-Cage Joint from a threaded joint to a slip joint to eliminate the effects of thermal expansion, achieved maximum thread engagement for existing thread in the Cage by increasing the thickness of the guide retaining plug (thread length was increased from 5/8" to 7/8"), shortening guide length by 3/16", and shortening disc length by 3/16". Hardness of the disc was increased from Rc 36-39 to Rc 40-42 to eliminate seat distortion (upsetting). The seat design was changed from a flat seat to a thermolip seat which has proved itself on other valve types to be superior on steam service. Piston rings were eliminated from the disc and disc diameter was increased slightly resulting in improved valve popping during tests. The final dash 2 design change was replacement of the retaining lock screw and slot in the guide retaining plug with a lock plate and lock screw. The effluent from the relief valve is routed to the quench tank through separate piping up to the common header immediately upstream of the quench tank.

The Dresser relief valve is flange mounted directly on an electric motor operated isolation valve. The isolation valve is flange bolted to a flanged pressurizer nozzle approximately 21 inches long. The relief and isolation valves allow the steam from the pressurizer to flow vertically through the pressurizer nozzle and both valves. A pipe elbow at the discharge of the relief valve turns the flow horizontally as it routes the effluent through the discharge piping.

The isolation valve is a 2500 lb. Velan Engineering Companies 2½" gate Model F9-454B-13MS driven by a Limitorque Operator Model SMB-00-10.

2. Unit 2

ANO-Unit 2 (ANO-2) is a Combustion Engineering PWR rated at 858 MW Net. The unit went commercial in March, 1980.

The ANO-2 overpressure protection for the reactor coolant system is provided by two Crosby HB-BP-86 6M6 Safety valves, each with a bore diameter of 2.154 in and a bore area of 3.644 in^2. The calculated rated flow for each safety valve is 118.46 lbm/sec at 2485 psig. The ANO-2 safety valves are connected directly to the pressurizer nozzles which are located at the top of the pressurizer. The valve inlet piping is 6" schedule 160 with a total length (at the longest) of 21.1 inches from the pressurizer to the flange mounting. The discharge from these valves is routed through separate piping up to the common header immediately upstream of the quench tank.

The ANO-2 Pressurizer does not have a PORV in its design.

PART II

DEMONSTRATION OF SAFETY/RELIEF VALVE OPERABILITY

A. Introduction

In July, 1980 EPRI submitted a copy of its Program Plan for the Performance Testing of PWR Safety and Relief Valves to the NRC. The NRC reviewed the test program prior to its implementation.

The NRC was given periodic progress reports as the testing took place.

On July 28, 1982 Arkansas Power & Light company submitted two letters (1CANØ78211 and 2CANØ78211) showing the applicability of the data to Arkansas Nuclear One Unit 1 and 2. These letters cited EPRI program documents which set out the test conditions, the means by which valves were selected to envelope characteristics of a class of valves, reports which were plant-specific to CE and B&W designs, and a test report. In addition these letters set out, section by section, AP&L's compliance with the NUREG 0737, Item II.D.1 requirements.

On November 30, 1982, Arkansas Power & Light Compnay submitted its evaluation of plant-specific discharge piping. (ØCAN118225).

On December 26, 1984, Arkansas Power & Light Company received the current request for additional information (ØCNA128414). Because of the complexity of the request, the time elapsed, and the fact that personnel immediately responsible for monitoring those tests have moved to other positions, AP&L asked for an extension of time from 30 to 120 days in which to bring its response (ØCANØ1851Ø).

During this period of time we contracted for preparation of safety/relief valve submittals for each Unit, which were reviewed by AP&L personnel familiar with the EPRI testing.

The submittal for Unit I, a Babcock & Wilcox unit, essentially draws together data from the EPRI test reports. The submittal for Unit II, a Combustion Engineering design, was prepared in the format of the report prepared for the Combustion Engineering Owners Group with plant-specific adjustments for ANO-2. At our request the contractor prepared a cover sheet referencing the questions asked in the request for additional information. Despite the detail of the current submittals, they achieve far less as a substantive contribution to the plant-specific data available to the NRC than they achieve as an exhaustive effort to organize the material into a format more compatible with approach which the NRC is now taking towards the review.

DEMONSTRATION OF SAFETY/RELIEF VALVE OPERABILITY
ARKANSAS NUCLEAR ONE

UNIT 1

QUESTION 1

In order to show that the results from the EPRI tests adequately demonstrate operability of the ANO-1 valves, more detailed information should be presented regarding the plant specific safety/relief valve system. Discuss the specific results from the EPRI tests as they apply to the ANO-1 safety and relief valves so as to show that these valves will open and reclose under expected flow conditions and will pass their rated flow.

RESPONSE

This response will be broken down to address the following subjects:

1.0 The specific safety/relief valve system.

2.0 The EPRI test results and their application to ANO-1.

3.0 Safety/relief valve performance on both steam and water.

1.0 SPECIFIC SAFETY AND RELIEF VALVE SYSTEM

1.1 Safety Valves

The overpressure protection for the reactor coolant system is provided by two Dresser model 31759A closed bonnet, 3" x 6", spring-loaded, self-actuated safety valves. Each valve is flange mounted on its own 3" ID x 21" long pressurizer nozzle. Each valve discharges into a six-inch schedule 40 pipe which routes the valve effluent to a quench tank.

Functionally and physically the 31759A valve, which was not tested, lies between the smaller Dresser 31739A valve, which was tested, and the larger 31709NA valve which was also tested in the EPRI test programs. All three valves are geometrically similar. It was the intent of the EPRI valve test program to test those valves which functionally bounded a series of valve models from a given valve manufacturer - hence, the testing of the 31739A and the 31709NA valves.

1.2. Relief Valve (PORV)

The relief valve mounted on the ANO-1 pressurizer in a Dresser Model 31533-VX-30-1 Electromatic PORV. It has a bolted bonnet with a 2 1/2"-2500# inlet flange and a 4"-600# outlet flange.

The effluent from the relief valve is routed to the same quench tank used by the safety valves. This valve has been modified to the dash 2 design. The dash 2 modifications include the following design improvements:

1. The Tube Insert-Cage Joint was changed from a threaded joint to a slip joint. The change eliminated the effect of thermal expansion in the joint.

2. The guide retaining plug was increased in thickness (thread length was increased from 5/8" to 7/8"). This achieved maximum thread engagement for the existing thread in the cage.

3. Guide length was shortened by 3/16" because of Item 2.

4. The disc length was shortened by 3/16" because of Item 2. The hardness of the disc was increased from Rc36-39 to Rc40-42. The increased hardness eliminated seat distortion (upsetting). The seat design was changed from a flat seat to a thermolip seat which has proven itself on other valve types to be superior on steam service. The disc outside diameter was increased slightly because of Item 5.

5. Piston rings were eliminated from the disc. Improved valve popping was experienced during tests.

6. The lock plate and lock screw replaced the retaining lock screw and slot in the guide retaining plug.

The Dresser relief valve which was performance tested as part of the EPRI valve test program was a Model 31533 VX-30-2. This valve is functionally identical to the ANO-1 valve except that it has a 1 5/16" bore, and consequently could pass more flow. The bore size should not adversely impact performance.

1.3 PORY Isolation Valve

The Dresser relief valve is flange mounted directly on an electric motor operated isolation valve. The isolation valve is flange bolted to a flanged pressurizer nozzle approximately 21 inches long. The relief and isolation valves allow the steam from the pressurizer to flow vertically through the pressurizer nozzle and both valves. A pipe elbow at the discharge of the relief valve turns the flow horizontally as it routes the effluent through the discharge piping.

The isolation valve is a 2500# Velan Engineering Companies 2 1/2" gate Model F9-454B-13MS driven by a Limitorque Operator Model SMB-00-10.

2.0 THE EPRI TEST RESULTS AND THEIR APPLICATION TO ANO-1

In general, the EPRI test program included the performance testing of safety valves, relief valves, and relief isolation valves.

The test program initially had as its goals the verification of performance parameters for safety and relief valves. Testing of relief isolation valves was not part of the initial program, but was implemented when it was discovered that some PORV isolation valves were malfunctioning.

2.1 Safety Valves

As the valve test program progressed it became clear that more information concerning safety valve design parameters was required. The safety valve portion of the test program turned into a quasi research program with large amounts of data being acquired and analyzed.

Under this portion of the program, EPRI contracted with Continuum Dynamics Inc. (CDI) to devise a relationship between valve performance and the test data that was being acquired. CDI developed a computer code called COUPLE which related the valve dynamics to the downstream and upstream pressure to predict flow and blowdown as a function of these parameters and ring position. This code was benchmarked against the EPRI valve test data. Subsequently the COUPLE code was modified to more closely model the performance of the Dresser valves only, as opposed to the previous requirement of relating parameters to the performance of all safety valves.

As discussed previously the Dresser 31759A valve was not part of the EPRI test program and therefore the valve performance was analyzed using the COUPLE code.

The capability of the Dresser 31759A valve to perform as required can be inferred by examining the EPRI test data for both the smaller and larger Dresser valve. Table 1 shows the important characteristics of all three valves and a summary of the test data for the smaller and larger valves.

From the table, the following can be noted:

1. Geometrically, the 31759A valve lies between the small Dresser valve and the large Dresser valve. The bore area and the ASME rated steam flow increases by a factor of approximately 1.3, progressing from the smaller valve to the larger valve, thus demonstrating the geometrical relationship between the valves.

2. The tabulated test runs for both valves indicate a grand total of 47. Only four of these runs were unstable, i.e. the valve chattered. The instability of one of these runs was caused by an improper middle ring adjustment (run number 201 for the 31709NA valve). Because of the adjustment error this valve cycled at 35 times/second for 122 seconds. The internals were deformed. However, the leak rate after termination of the test was only 0.54 GPM.

3. Of paramount importance is the fact that all valves opened as required during every run and no valve stuck open under any of the testing conditions.

4. Out of a total of 34 cycles (loop seals not included), only four proved to be unstable and one of those was due to human error. As noted above, on B&W plants the safety valves mount on the pressurizer and hence do not have loop seals therefore the loop seal runs were not included.

5. Based on the performance of the larger and the smaller valve, it is concluded that the 31759A valve can perform at least as well.

TABLE 1

SIGNIFICANT ASPECTS OF THE DRESSER SAFETY VALVES

		31739A (Tested Valve)	31759A (ANO-1)	31709NA (Tested Valve)
1.	Valve Inlet Dia, in.	2.5	3.0	6
2.	Valve Outlet Dia, in.	6.0	6.0	8
3.	Bore Area, in^2	2.545	3.338	4.339
4.	Min. Lift, in	0.45	0.526	0.588
5.	ASME Rated Steam Flow @ 2575 psig, lb/hr	297,845	391,000	507,918
6.	No. of Test Runs w/Steam	25	Enveloped by Valves Tested	9
7.	No. of Test Runs w/Steam Water Transition	2		2
8.	No. of Test Runs w/Water	5		4
9.	No. of Test Runs w/Loop Seal Config.	12		1
10.	No. of Test Runs w/No Loop Seal Config. (B&W plants)	20		14
11.	No. of Runs w/Unstable Valve Performance	2		2
12.	No. of Runs Where Valve Failed to Open	0		0
13.	No. of Runs Where Valve Stuck Open	0		0
14.	No. of Runs Where Post-Test Leakage Exceeded Pre-Test Leakage	12		11
15.	No. of runs Where Leakage Exceeded 1 GPM	3		5
16.	No. of Runs Where Leakage Exceeded 2.5 GPM	0		0

A Dresser 31739A Valve, similar to the valve at ANO-1 was challenged during the February 26, 1980 transient at Crystal River-3.

During this transient one safety valve opened at approximately 2400 psig and passed subcooled water for about 15 minutes. The water temperature ranged from 560°F to 515°F before closing (Reference 12, Section IV, Item 1). The normal lift point for this valve was 2500 psig, but because it was leaking prior to the transient, the valve lifted light by 100 psi.

During the as-received inspection of the valve, prior to refurbishment by Wyle Labs, the lift point of approximately 2400 psig was duplicated. Leakage of 1.1 gpm was measured, indicating that the valve had not suffered any substantive damage (Reference 12, Appendix C, page 14).

This demonstration of valve operability under actual field conditions increases our confidence that these safety valves will perform as expected, and is consistent with the test findings.

2.2 Pressurizer Pilot Operated Relief Valve (PORV)

As discussed under paragraph 1.2, the Dresser valve which was performance tested at the Wyle Laboratory as part of the EPRI test program was a Model 31533 VX-30-2. This valve differed from the ANO-1 PORV in that the bore was 1 5/16" vs. 1 3/32". The larger bore for the test valves implies a larger capacity for the same operating conditions.

Table 2 presents a summary of the EPRI tests.

TABLE 2

SUMMARY OF IMPORTANT ASPECTS
OF THE DRESSER PORV PERFORMANCE
TESTING (REFERENCE 1)

1.	Total No. of Runs	12
2.	No. of Steam Runs	3
3.	No. of Water Runs	6
4.	No. of Steam/Water Transition Runs	1
5.	No. of Water Seal Simulation Runs	3
6.	No. of Runs Where Valve Opened on Demand	12
7.	No. of Runs Where Valve Closed on Demand	9
8.	No. of Runs Where Valve Did Not Close on Demand[1]	3
9.	No. of Runs With Steam or Water at a Temp. Greater Than 600°F	9
10.	No. of Runs With Water at a Temp. of Between 450°F and 460°F	2
11.	No. of Runs With Water at Approximately 100°F	1
12.	No. of Water Runs With 25,500 in-lb (2125 ft-lb) Bending Moment	1
13.	No. of Runs Whose Post-Test Leakage Rate Exceeded The Pre-Test Leakage Rate	3
14.	No. of Runs Whose Leakage Rate at Any Time Exceeded 0.026 GPM	0.0

[1] Only those runs simulating water seals did not close on demand. ANO Unit 1 does not have a water seal, therefore the information from these runs does not apply.

From Table 2 the following conclusions are made:

1. Combining the moments imposed on the PORV flanges (as calculated by NUTECH, Reference 2, and as analyzed and approved by Dresser, Reference 3), the resultant is approximately 17,000 in-lb. The bending moment imposed during the EPRI test was 25,500 in-lb. (Item 12 in Table 2).

2. The data relevant to the proper operability of the ANO-1 PORV indicates that the valve opened, closed and had no significant leakage.

2.3 PORV Isolation Valve

In paragraph 1.3 a description of the isolation (block) valve was given. It is a 2 1/2" gate valve manufactured by Velan.

The valva used in the EPRI test program as described in Reference 4 was a 3"-1500# Velan Model B10-3054B-13MS gate valve. Although the size and pressure rating are different, the internals are similar to the ANO-1 block valve.

Two series of runs were made using the same valve and different Limitorque operators. The first series used a SB-00-15 operator and the second series used a SMB-000-10 operator. A total of 84 open-closed cycles were accumulated for both series. All stroking of the valve was satisfactory with respect to stroke time, opening and closing on demand and zero leakage.

Perhaps the most convincing evidence of valve operability is the performance of a Velan valve identical to the ANO-1 PORV isolation valve and operator at TMI-2 shortly after the major accident. The TMI-2 valve was cycled in excess of 30 full open/closed cycles as described in Reference 5. Thirty of the cycles occurred during a period of two hours when the upstream pressure ranged between 1865 and 2150 psig. Cycling was discontinued when the reactor plant was brought under control and the valve was placed in the closed position.

From the EPRI test program and the performance of the valve under field conditions, it is concluded that the ANO-1 PORV isolation valve will operate as required.

3.0 SAFETY AND RELIEF VALVE PERFORMANCE ON BOTH STEAM AND WATER

3.1 Safety Valves

In general, it can be said that the middle ring position provides the greater impact on valve lift, flow and blowdown in conjunction with the flow-generated backpressure.

The impact of backpressure on valve operation was discovered as a result of the EPRI Valve Test Program. At this time, it was determined that the backpressure was directly related to the body bowl pressure which increased as the backpressure increased. The body bowl pressure in turn acts on an uncompensated area of the disc to produce forces which add to the closing forces of the spring. Hence the size of the uncompensated areas and the magnitude of the spring constants play an important role in determining how far the valve will open and the amount of fluid that will pass through the valve as it performs it relieving function.

Opposing the forces created by the spring and the backpressure are the additive static and dynamic forces generated by the inlet fluid (e.g. steam). After the valve opens slightly as a result of the increased static pressure in the pressurizer, additional forces created by the steam dynamics act to further oppose the spring. In the initial absence of backpressure, this will raise the stem to its uppermost position. As the flow exiting the valve starts to build up backpressure, the backpressure acting on the uncompensated area of the disc forces the valve to pinch down on the flow. The reduction in flow reduces the backpressure and the valve tends to open slightly. This process continues until all the forces (including those created by the changing valve inlet pressure) establish an equilibrium condition of valve position and mass flow rate.

The steam dynamic forces are in part controlled by the position of the middle ring. As the steam follows its path out of the valve nozzle into the body bowl, the position of the middle ring controls the change in momentum. Positioning the middle ring in the direction below the disc/seat interface (designated as the negative direction) increases these forces. The more negative the position of the ring, the more lifting forces are provided to the disc and the greater the valve blowdown assuming all other factors remain constant.

To predict the behavior of the Dresser valve, all of the forces and their interaction with each other must be understood and taken into account from the time the valve opens until it closes.

The COUPLE code which was developed and benchmarked as part of the EPRI valve test program performs this function and has been used to predict the required position of the middle ring for a desired performance if the valve inlet and outlet characteristics are known.

The COUPLE code analysis for the ANO-1 31759A valves indicated the strongest (i.e. most negative) position was required by the middle ring to counteract the backpressure produced by the relatively large flow through the discharge piping.

In order to identify a practical limit for the negative middle ring position of the 31759A valves, it was decided to use a position corresponding to a scaled geometric position of the most negative value actually tested on a 31739A valve during the EPRI test program. This value for the 31739A valve was -80 notches, from test number 1008; it corresponds to a -93 position for the 31759A valve.

With the COUPLE code this ring position produced a calculated 100% ASME flow rate with 85% of the rated stem lift at 7% accumulation. The resulting blowdown was predicted to be 8.6%.

With respect to the adequacy of water flow through the valve, if the EPRI Test data is examined for both the smaller (31739A) and the larger (31709NA) valves, it will be seen that for all water as well as steam-to-water transition runs, the flow through either valve is in excess of the minimum required flow rate of 6805 lb/min. (Reference 6) for 400°F water. Only two of the ten runs (five for each size valve) had a backpressure less than the backpressure (250 psia) calculated by Teledyne Engineering Services (Reference 7). All but one of the flows had an inlet pressure less than 2500 psia at the point in time when the flows were identified indicating that the flows would have been higher if the inlet pressure had been 2500 psig. This examination documents the capability of the smaller and larger valve to flow 400°F water in excess of the required amount for ANO-1, i.e. after a steam line break. It is therefore concluded, based on the geometrical similarity of all three valves, that the middle-sized valve would also flow more than the required amount of 400°F water.

3.2 PORV

A discrepancy exists between the flow rates recorded for saturated steam at Marshall Station and Wyle laboratories in Norco, CA. The values recorded at Norco are considerably less than those recorded at Marshall Station even though the valves are ostensibly identical and the operating conditions are similar. Table 3 indicates these differences.

TABLE 3

REPRESENTATIVE COMPARISON OF
SATURATED STEAM FLOW RATES
AND PRESSURE DROPS AT WYLE LABS
AND MARSHALL STATION

	Inlet Pressure (PSIG)	Outlet Pressure[1] (PSIG)	Flow Rate lb/hr
Marshall Station	2300	400	156,534
(Data Recorded 12/17/80)	2310	160	156,259
Wyle Lab - Run #10	2303	655	133,200
- Run #23	2265	438	132,480

[1] Because the flow is choked in the valve, the flow rate is insensitive to a reduction in downstream pressure.

The calculated steam flow based on Napler's equation for the Marshall Station conditions is

$W = k_D 51.5AP$ where K_D 0.95

$A = \pi/4\ (1.3125)^2 = 1.352 in^2$

$P = 2335$ psia

W = 154,500 lb/hr

The measured flow at Marshall Station for these conditions was 156,500 lb/hr. The calculated value, i.e. the design flow rate, missed the measured value by less than 2%. From these results it can be concluded that the Marshall Station values are more nearly correct.

One possible reason for the discrepancy between the two values is that they were not obtained under identical condition.

With respect to water flow through the PORV, examination of the tests performed by Wyle Labs (Ref 1) indicates that six runs were made covering the following ranges:

Inlet Pressure, psig	690 to 2400
Inlet Temperature, F	100 to 650
Flow Rate, lb/hr	26,000 to 625,000

The tests were run primarily to verify operational capability of the PORV. The quantitative flow rates are not important because no requirement exists for water flow through the PORV.

QUESTION 2:

Provide sufficient evidence to show that limiting transients corresponding to steam and liquid flow conditions have been identified through analysis of the accidents and operational occurrences referenced in Reg. Guide 1.70, Rev. 2. Show that the fluid inlet conditions determined for these limiting transients were enveloped in the EPRI tests and that the test pressures were the highest predicted by conventional safety analysis for the limiting transients.

RESPONSE:

This response will be broken down to address the following subjects:

1.0 The methodology used in determining the bounding fluid conditions
2.0 The transients considered for evaluating valve performance
3.0 The bounding fluid conditions
4.0 The comparison with EPRI results

1.0 Methodology

The methodology used in determining the bounding fluid conditions for the EPRI program, as outlined in Reference 6, shows that the limiting transients that produce the bounding fluid conditions for the safety and relief valves have been identified per Reg. Guide 1.70, Rev. 2. A general description of the methodology used for the identification of the limiting fluid conditions is given here.

The latest amendments (as of December 1982 for all the B&W 177 FA Plants) of the Safety Analysis Reports were reviewed to determine which transients/accidents were considered in the licensing basis of each plant. The transients/accidents thus identified were reviewed generically to determine whether they would be predicted to challenge the Pilot Operated Relief Valve (PORV) and/or Pressurizer Safety Valves (PSV) or result in automatic actuation of the High Pressure Injection (HPI) System.

The existing analyses were then reviewed to determine the expected valve inlet fluid conditions for those transients/accidents identified to challenge the PORV and/or PSV's.

For the events that resulted in automatic actuation of the HPI System, a qualitative evaluation was performed to determine the bounding plant conditions that could evolve as a result of extended operation of the HPI system. In addition, consideration was given to the conditions resulting from spurious HPI actuation at power. The maximum duration of water flow through the PSV's and PORV depends upon the extended operation of HPI after the pressurizer becomes full of water.

The PORV, as part of the low temperature overprotection system, and the applicable overpressure protection reports were reviewed to determine the bounding PORV inlet fluid conditions. It is to be noted that the PORV is considered a functional valve for pressure control and as such safety analyses and accident analyses do not take the PORV into account. So in this document, the bounding values of PSV's were also applied to the PORV, although this method has a great degree of conservatism.

Once the bounding conditions of the fluid state, flow rates and duration were determined (See Reference 6), the conditions were compared with the results of the EPRI tests. The comparison showed that both the Dresser valves tested (31739A and 31709NA) functioned adequately under the generic 177 FA plant bounding fluid conditions -- which include the bounding fluid conditions of ANO-1.

2.0 Transients Considered for Evaluating Valve Performance

Reference 6 documents the details of the procedures used to arrive at the bounding set of valve inlet fluid conditions that were used in the EPRI tests. Here, the same set of details are repeated in the condensed form. The transients and accidents used in the evaluation of

bounding fluid conditions are obtained from various B&W 177 FA Plant FSAR's, including those of ANO-1. Many of the bounding values are from plants other than ANO-1 and these values do encompass ANO-1 values. This means that there is a certain degree of conservatism in the values used for the evaluation of the valve test results for ANO-1.

Three categories of events, transients and accidents are considered, in arriving at the bounding fluid conditions, including flow rates:

1. Typical FSAR transients and accidents.
2. Cold RCS pressurization transients.
3. Transients resulting from extended operation of the HPI System following initiation caused by a typical FSAR transient/accident.

Table 4 gives the list of transients/accidents that can challenge the PORV and/or PSV's at ANO-1 (and other 177 Fuel Assembly B&W plants). The data base used for the bounding value determination comes from analyses performed for various plants with FSARs of various vintages and also includes some non-FSAR transients.

Table 5 gives the list of transients/accidents that can result in automatic HPI actuation. For the transients that challenge the PORV and/or PSV's, the existing FSAR analyses were reviewed and the following were developed:

1. A generic event description that includes the order and approximate time duration of each fluid state that could exist at the valve inlet.

2. Typical NSS response characteristics for the B&W 177 FA plants, e.g., pressurizer pressure, surge line flow, surge flow temperature, pressurizer level, pressurizer pressurization rate and possible fluid state at valve inlet.

3. Representative values of the PORV and PSV inlet conditions for the B&W 177 FA plants. Included are valve inlet pressure ramp rates, maximum pressurizer pressure and the valve inlet fluid state.

Various combinations of the events that can result in entirely different responses were also investigated. With these as a base, the bounding fluid conditions for the valves were selected. These fluid conditions were covered in the EPRI test spectrum.

The loss of coolant accident (LOCA) analyses reviewed included a stuck-open PORV following an inadvertent actuation or actuation due to a loss of main feedwater (FW). The stuck-open PORV LOCA's do not challenge the PSV's and hence are not included in the PSV events. Larger LOCAs are not expected to challenge the PSV's.

The second category of events reviewed includes cold RCS pressurization events. PSV's are not challenged in these events. The PORV is used as part of the cold overpressurization protection system in these events.

The third category of events investigated is the extended HPI operation events. These give the surge flow rates and coolant inflow temperatures into the pressurizer and hence the liquid flow rates through the PSV's and the PORV when the pressurizer is full.

TABLE 4

Transients/Accidents expected to challenge the PORV and/or PSV's.

FW System malfunction - decrease in FW temperature
FW System malfunction - increase in FW flow
Pressure Regulator Malfunction resulting in decreased steam flow
Loss of Load
Turbine trip with reactor trip
MSIV closure at full power
Loss of condenser vacuum
Loss of all power
Loss of normal feedwater
FW Line Break
Rod bank withdrawal from subcritical conditions (Start-up accident)
Rod bank withdrawal from power
Rod drop
RC pump start-up
Boron dilution
Rod ejection
Loss of coolant accidents (LOCA)

TABLE 5

Transients that result in automatic HPI actuation.

Steam pressure regulator malfunction increasing steam flow

Steam line break

Feedwater line break

Inadvertent opening of PSV

Instrument line break

Loss of coolant accidents (LOCA)

3.0 Bounding Fluid Conditions

The bounding fluid conditions identified from the transients in Section 2 are contained in Reference 6. They are summarized below, along with the reference to applicable table in Reference 6.

3.1 PORV:

1. Cold pressurization events:

   Makeup control valve fails open. PORV set point is 550 psig open, 500 psig close. Fluid state at inlet: Saturated steam at 565 psia. (Table 6-3 of Reference 6).

2. Extended HPI operation following an FSAR steam line break:

   PORV set to open at 2450 psig,
   Maximum source pressure 2500 psig, Temperature 602°F.
   Initial flow of steam followed by subcooled water at 400°F minimum temperature; PSVs also lift when water is being relieved. (Table 6-2 of Reference 6).

3. FW Line Break: PORV set to open at 2450 psig.
   Maximum source pressure 2500 psig.
   Temperature of fluid, 640°F Maximum-602°F Minimum.
   Steam flows initially and subcooled water subsequently.
   (Table 6-3 of Reference 6).

4. Rod ejection at Hot Zero Power: PORV inlet condition: Steam at 2662 psig. (Table 6-1 of Reference 6).

5. The maximum required steam relief rate for the PORV due to accident/transient conditions occurs in the pressurizer heaters erroneously energized event. This value is 7555 lb/hour of saturated steam. (Page 4-26, Table 4-19 of Reference 6).

Note that the PORV is not required to pass a given quantity of steam for any of the FSAR events as the PORV is not needed for safety but for operational control of pressure. So in all safety analyses, the PORV is assumed failed closed.

Based on the above enveloping events, the following conditions for the PORV operation can be considered as a reasonable set of bounding inlet conditions.

PORV set point: Normal: 2450 psig open.
For makeup control valve failure event: 550 psig open, 500 psig close.

Maximum source pressure: 565 psia saturated steam and water at 400°F for the makeup control valve failure event.
2500 psig saturated steam and water at 602°F and 400°F in the steam line break event.
2500 psig saturated steam and water at 640°F for FW line break.
2662 psig saturated steam for rod ejection hot zero power event.

Maximum steam flow: For a strictly PORV event, 7555 lbs/hour. This occurs in the pressurizer heater energizing event. Higher relief may occur in safety related events, but in these analyses the PORV is assumed failed closed.

Maximum water flow: 400°F water at 650 gpm based on makeup valve failure and HPI injection rate. These flow rates will open both PSV's and PORV.

Pressurizer pressure: 565 psia minimum when PORV needs to open for one lower bounding accident. 2677 psia maximum for other conditions.

3.2 PSV

1. Steam Line Break:
   PSV's set at 2500 psig. Initial steam flow followed by subcooled water. 602°F maximum water temp, 400°F minimum (Table 5-2 of Reference 6).
   At 602°F, 6555 lbs/minute of water.
   At 400°F, 6805 lbs/minute of water at 2465 psia.

2. FW Line Break:
   PSV set at 2500 psig. Steam relief with subsequent water relief.
   (Table 5-2 of Reference 6).
   At 640°F, water flow is 11,520 lbs/minute
   At 602°F, water flow is 10,400 lbs/minute

3. Rod Ejection At Zero Power:
   PSV opens at 2575 psig source pressure. Steam at 2662 psig maximum source pressure. This event defines the maximum system pressurization rate of 175 psi/second.

4. Total HPI flow through PSV's at PSV lift pressure of 2500 psig is 620 gpm of water at 400°F.
   Estimated duration 120 seconds. Suggested water flow duration is 10 minutes assuming operator action to cut off HPI flow. This time can be longer if HPI feed and bleed mode of long term cooling is used.

4.0 Comparison with EPRI Results

4.1 PORV

EPRI tests conducted to quality PORV's at Wyle Laboratory, as applicable to ANO-1, were on Dresser valve model 31533 VX-30-2. As mentioned earlier, the ANO-1 PORV is model 31533 VS-30-1, the difference being that the model tested had a bore of 1 5/16" as

against 1 3/32" in ANO-1. Reference 1 gives the results of the tests. Relief of water and steam at the identified inlet conditions do satisfy the expected performance characteristics of the PORV without failures.

As the PORV is not a safety related component, as mentioned earlier, analytically derived maximum flowrates based on PSV flow rates and other conditions are perhaps overly conservative to apply to PORV's. Functionally, the PORV tested performed satisfactorily. As the model tested has a smaller throat area than the ANO-1 valve, proportionately higher maximum relief rates would be expected of the ANO-1 valve.

When water relief is expected through the PORV, the PSVs will also be open and relieving water, and if the PSVs are tested to relieve the total quantity of water, PORV relief is redundant. This is the case for ANO-1. The test results indicate a minimum water relief of 262,800 lbs/hour. Post test leakage was acceptable (<0.00013 gpm measured) indicating survivability of the valve in passing water over a period of time. The period of the tests with water ranged from 10 to 15 second. (Reference 1)

4.2 PSV's

The two valves (PSV's) tested performed as required under analytically identified conditions that bound ANO-1 and it is reasonable to assume that the actual ANO-1 valve will perform as expected.

The Dresser valve model 31709 NA gave the following performance data:

Rated Steam Flow	507,918 labs/hour
Pressurization tested range	2.9 to 322 psi/sec

The steam flow rate corresponds to the design flow rate under the various inlet conditions expected and indicates performance per design expectations. This encompasses the 7555 lbs/hour flow needed through the PORV under one analyzed accident condition (pressurizer heater energized condition).

Test numbers 201, 603, 606, 611, 614, 615, 618, 620 & 1305 are the steam tests in this series of tests. All these tests have tank pressure greater than 2468 psia with pressurization rates ranging from 2.9 psi/sec to 400 psi/sec.

All other tests mentioned here (with blowdown ranging from 8.6% to 14.2%) were stable and the lowest percent rated steam flow was greater than 116% of the rated flow. The maximum required steam flow for ANO-1 is less than the rated flow of this valve.

The setpoint for valve opening in these tests ranges between 2503 psia and 2568 psia.

For the PSV's, the opening setpoint of 2515 psia is in the range of the tests. The maximum pressurization rate of 175 psi/sec required for ANO-1 valves is lower than the test value for numbers 606, 611, 614, 615, 618, 620 and 1305 and in all the tests the valve responded very well to rates higher than the required rate.

If we consider the bounding water flow conditions for the PSV's, the PSV opening pressure is in the range tested. Water flow required of 11,520 lbs/min gives 691,200 lbs/hour at 640°F and 2515 psia. This is 136.1% of the rated steam flow for this valve.

Under water inlet conditions, there are four applicable tests, numbers 625, 630, 1308 and 1311. (Test 1311 is neglected due to lack of data). When the PSV's are passing water, already the pressure has reached above the opening point of the PSV's and the PORV will be open. This means the rate of pressure increase will

be very low compared to the maximum rate of 175 psi/sec. This imports that for PSV's the pressurization rate may not be meaningful. The maximum steady liquid flow for this set of tests, (a minimum of 1646 gpm is shown for test 1308):

> 11520 lbs/min at 640°f at 2515 psia has a specific volume of 0.02532 ft^3/lbm which gives 0.02532 ft^3/lbm which gives 0.02532 x 7.48 gal/lbm. So the flowrate is = 2181.9 gal/minute.

It was found except for test number 1308, that all of these tests pass higher flows under steady flow conditions. Test number 1308 has an inlet temperature of 535°F at 2487 psi tank pressure but the maximum flow at ANO-1 occurs at 640°F and the tests at 625°F or 603°F do show that the required flowrate of water is easily achievable. Therefore, this valve can handle the ANO-1 bounding conditions adequately.

All the above discussions are based on test results of the larger Dresser model tested, 31709NA.

Let us look at the smaller Dresser valve tested. This valve is Dresser model 31739A. Reference 10 gives the results of the tests.

This valve is 2 1/2" inlet with a 6" outlet, a pressure setpoint of 2500 psig and a rated flow of 297,845 lbs of steam/hour.

Based on tank pressure, Table 4.4 of Reference 10 gives the following tests as valid for our use:

> At 3% accumulation, test numbers 304, 306, 308, 310, 312, 314, 316, 318, 322, 324, 326, 328, 1005, 1008, 1011, 1012, 1018 & 1104a.

All of the above tests have a steam pressurization rate above the maximum 175 psi/sec shown in the analytical envelope conditions for ANO-1 earlier.

The maximum allowable blowdown rate for ANO-1 (20% from Reference 11) is higher than the blowdown obtained in any of these tests (5.8% to 14.2% for the 31739A valve and 7.5% to 14.2% for the 31709NA valve) and hence the consequences of increased blowdowns are not meaningful and are not discussed.

For the ANO-1 PSV's, the maximum water flow rate is higher than steam flow rate. So let us look at maximum water flow rate at 640°F of 11,520 lbs/minute which is 2181.9 gpm.

The water tests show a maximum steady liquid flow rate of 1128 to 2498 gpm. As some of these are lower than the ANO-1 requirement, we will be more specific about inlet conditions, to eliminate the inapplicable tests.

For the feedwater line break with all surge flow going through the PSV's, the pressure is 2500 psig with water at 640°F which gives the maximum water flow rate through the PSV of 2181.9 gpm.

Test number 1027 gives, for a tank pressure of 2350 psia, and a temperature of 621°F, a flow of 2492 gpm with a back pressure of 580 psia and satisfies the requirement of ANO-1 for water flow.

As steam flow requirements are far less severe than the water flow requirements for the PSV's, the rated capacity for steam flow of the valve exceeds the requirement and in all tests the minimum flow exceeds steam flow requirements. The steam tests also indicate that rated steam flows were achieved in the applicable tests.

The survivability of the PSV's for the duration of water flow is consistent with the test reports and supported by field experience. As stated earlier, the PSV's may need to pass 650 gpm for a prolonged period of time under HPI injection conditions. This is far less than the minimum steady state flows tested but the duration of the tests ranges from 50 seconds to 220 seconds minimum. However, it is relevant to mention here that at the Crystal River-3 plant on February 26, 1980, the Dresser valve 31739A performed well in passing subcooled water for about 15 minutes at 2500 psig (approximately). The water temperature ranged between 560°F and 515°F. This valve had a leakage of 1.1 gpm when measured at the Wyle Labs before refurbishment, after this incident (See Reference 12).

QUESTION 3:

Along with other fluid conditions, identify the total length of time of liquid flow through the safety valves for transients producing water flow, and assure that the valve functionability will not be impaired by liquid flow of this duration.

RESPONSE:

The fluid conditions at extreme flow conditions as identified by analyses for ANO-1 are shown in Section 3.2 response to Question 2. The maximum flow rate of 2181.9 gpm identified at 640°F and 2500 psig inlet conditions falls below the steady state water flows observed for similar conditions in the tests.

The maximum duration of water flow in the PORV tests at Wyle Labs was 15 seconds. In the PSV tests, the duration of flow was 50 to 220 seconds. Analytical estimates of water flow under the maximum flow conditions are on the order of 120 seconds. However, under uncontrolled HPI injection to cool the core in a feed and bleed case, the duration of the water flow through the PSV's can be much longer than the 220 seconds tested, depending on

operator action, but the flow rate required under this condition is only 620 gpm. Although the duration of the test is less than can be postulated, it is relevant to mention here that at Florida Power Corporation's Crystal River-3 Plant on February 26, 1980, the Dresser 31739A valve passed water for approximately 15 minutes with negligible damage to the valve (Reference 12).

QUESTION 4:

Show that the events investigated in selecting the limiting transients meet the NUREG 0737 requirement that single failures be chosen so as to maximize dynamic forces on the Safety/relief valves and piping.

RESPONSE:

The events considered to arrive at the bounding values for the EPRI tests include the FSAR amendments of all the B&W 177 Fuel Assembly plants up to December, 1982 and as such the licensing bases for these plants do comply with NUREG 0737 requirements of single failures in the transient evaluations.

Although the ANO-1 licensing base pre-dates NUREG 0737, the EPRI tests were based on Reference 6 which does include the NUREG 0737 - related updated evaluations of the various transients.

QUESTION 5

Additionally, present more detail on the differences between the test and plant piping configuration (inlet and discharge) indicating the effects these differences have on valve operability.

RESPONSE

The differences in the piping configurations between the test facilities and ANO-1 are presented below. The inlet pressure drop for both the test loops and ANO-1 is not significant with respect to valve operability. It meets the valve manufacturers recommendation of being less than 50% of the blowdown.

Loads imposed on the valves by the piping in the test facilities were controlled to determine the effect on valve operability. This issue is discussed in the response to Question 10.

Comparison of Piping Configurations

	Inlet Piping	Outlet Piping
SAFETY VALVES		
1. EPRI/C-E Test Loop Configuration	8" reduced to 6" with inlet venturi total length - less than 2 ft. between valve and accumulator	6" enlarged to 8" sch 40
2. ANO-1	3" - 2500# flange pzr nozzle - 21" long	6" sch 40

PORV

1.	EPRI/Wyle Test Loop Configuration	3" - 1500# flanged vertical piping	4" sch 80
2.	ANO-1	2 1/2" pzr nozzle 21" long with a 2500# flange. 2 1/2" block valve mounted between PORV and pzr nozzle.	4" sch 40

Flow induced backpressures exhibited during the testing were also intended to determine the effect on valve operability. See Section 2.1 and 3.1 of the response to Question 1.

QUESTION 6

Identify the plant ring settings used.

RESPONSE:

Top ring	-48
Middle ring	-93
Lower ring	+8

QUESTION 7:

Explain how the expected blowdowns corresponding to these ring settings were extrapolated or calculated from test data.

RESPONSE:

See Section 3.1 of the response to Question 1.

QUESTION 8:

Provide assurance that the safety valves will pass their rated flow at the plant ring settings and that the valves will perform and operate acceptably under the expected back pressures and blowdowns.

RESPONSE:

See Section 3.1 of the response to Question 1.

QUESTION 9:

If the expected blowdowns exceed the valve design values, then address the consequences of increased blowdowns, such as a rise in pressurizer level and possible inadequate core cooling.

RESPONSE:

The tests indicate that the expected blowdowns fall well within the maximum tolerable blowdown of 20% for ANO-1 (See References 1, 10, 11 and 13) that will not precipitate the consequences stated in the question.

QUESTION 10:

Provide a comparison of the inlet pressure drop for the test loop and the plant.

RESPONSE:

A representative valve inlet pressure drop for both ANO-1 and the EPRI test loop is presented below for comparison:

	P. psi	m. lb/hr
ANO-1 (Ref. 8)	0.469	423,000
EPRI Test Loop Run #318 (31739A)	10	380,000

If the flow in the EPRI test loop was increased to 423,000 lb/hr, the inlet pressure drop would be approximately 12.5 psi. In either facility the inlet pressure drop is insignificant with respect to valve operability.

QUESTION 11:

Bending moments are induced on the safety/relief valves during the time they are required to operate because of the discharge loads and thermal expansion of the pressurizer tank and inlet piping. Show that a bending moment sufficient in magnitude to account for these loads was applied during operability tests.

RESPONSE:

The calculated bending moments imposed on the safety/relief valves that were generated by NUTECH in Reference 2, were combined as shown in Reference 9. The results are compared with the EPRI loadings as shown below.

ANO-1 Valve	Combined Calculated Moments	EPRI Test Valves	Imposed Loadings
31533-VX-30-1	16,599 in-lb	31533-VX-30-2	25,500 in-lb.
PSV-1001	61,396 in-lb	31739A	241,738 in-lb. Max (Run 1011)
PSV-1002	54,800 in-lb	31709NA	473,200 in-lb. Max (Run 1308)

From the above, it does not appear that the 31759A valves will have any operability problems as a result of the calculated bending moments.

QUESTION 12:

NUREG-0737, Item II.D.1 requires that plant-specific PORV control circuitry be qualified for design-basis transients and accidents. Please provide information which demonstrates that this requirement has been fulfilled.

RESPONSE:

The question is unclear as to the meaning of "qualification" of PORV control circuitry. It is obvious that environmental qualification of the PORV (and therefore its control circuitry) is not required by NRC regulations (10 CFR 50.49) and we do not believe that such is implied in the text of NUREG 0737 Item II.D.1.

The opening of the PORV is not a safety function and isolation of the PORV can be performed by the safety related block valve (which is qualified per 10 CFR 50.49).

The only electrical portion of the PORV is the integrally mounted pilot solenoid assembly. This assembly is considered to be functionally qualified based on the successful performance of the valves in the EPRI test program. All other components of the control circuit (with the exception of the connecting cable) are located outside of the reactor building and are not affected by fluid conditions, flow rates or other parameters of valve performance.

<u>QUESTION 13</u>:

Provide a justification as to how results of the Marshall Station tests or other tests can be used to demonstrate operability of the ANO-1 block valve for the required fluid conditions.

<u>RESPONSE</u>:

See Section 2.3 of the response to Question 1.

<u>QUESTION 14</u>:

Account for the differences between the ANO-1 block valve and operator and the test valve (and operator).

<u>RESPONSE</u>:

See Section 2.3 of the response to Question 1.

REFERENCES

1. EPRI/Wyle Power Operated Relief Valve Phase III Test Report - Vol. 3 EPRI NP-2670-LD Interim Report 10/82.

2. ANO-1 Pzr S/RV Discharge Piping Modifications, B&W ID 51-1020986-00, (NUTECH transmittal APL-12-015, 1/6/83, Arterburn to Trimble)

3. Design Report, B&W ID 33-1011480-00, Dresser ID - SR-315-11/317-21 Rev. 01.

4. EPRI-Marshall Electric Motor-Operated Valve (Block Valve) Interim Test Data Report, NP-2514-LD 07/82.

5. Analysis of Three Mile Island - Unit 2 Accident, NSAC-1, 07/79, pg. 40.

6. Valve Inlet Fluid Conditions for Pressurizer Safety and Relief Valves for B&W 177-FA and 205-FA Plants, EPRI NO-2352, Final Report 12/82.

7. Teledyne Engineering Services Technical Report - TR 5589-1.

8. Teledyne Engineering Services Technical Report - TR-5704-1. (This is a Sacramento Municipal Utility District report which is applicable to ANO-1 because the inlet nozzles to the pressurizer valves are identical to ANO-1).

9. Effect of Imposed Bending Moments on Valve Operability - B&W ID 32-1156779-00.

10. Valve Test Report (EPRI) for Dresser 31739A, EPRI Interim Report Vol. 3 of 10, "Test Results for Dresser Safety Valve Model 31739 A", July 1982.

11. B&W Document 77-1135671-00, "Pressurizer Safety Valve Maximum Allowable Blowdown", August 1982.

12. EPRI NP-80-13-LD, "Examination and Test of Crystal River Unit No. 3 Power-Operated Relief and Safety Valves", Interim Report, December, 1980.

13. Valve Test Report (EPRI) for Dresser 31709 NA: EPRI NP-2770-LD Vol. 4, March 1983.

DEMONSTRATION OF SAFETY/RELIEF VALVE OPERABILITY

ARKANSAS NUCLEAR ONE - UNIT 2

Cross Reference Between NRC Information Request
and Arkansas Nuclear One-Unit 2
Pressurizer Safety Valve Operability Report

1. Discuss the specific results from the EPRI tests to show that the safety valves will open and reclose under expected flow conditions and will pass their rated flow.

   Response: Refer to Part B.

2. Provide sufficient evidence to show that limiting transients corresponding to steam and liquid flow conditions have been identified through analysis of the accidents and operational occurrences referenced in Reg. Guide 1.70 Rev. 2. Show that the fluid inlet conditions determined for these limiting transients were enveloped in the EPRI tests and that the test pressures were the highest predicted by conventional safety analysis for the limiting transients.

   Response: Refer to Sections B1.2, C1.2, C2.2.

3. Along with other fluid conditions, identify the total length of time of liquid flow through the safety valves for transients producing water flow and assure that the valve functionability will not be impaired by liquid flow of this duration.

   Response: Appendix A justifies that no liquid will flow through the Arkansas Nuclear One-Unit 2 pressurizer safety valves.

4. Show that the events investigated in selecting the limiting transients meet the NUREG-0737 requirement that single failures be chosen so as to maximize dynamic forces on the safety/relief valves and piping.

   Response: Refer to Section C1.2

5. Present more detail on the differences between the test and plant piping configuration (inlet and discharge) indicating the effects these differences have on valve operability.

   Response: Refer to Sections B4.2, C1.3, C2.1.

6. Identify the plant ring settings used.

   Response: Refer to Section C2.4.

7. Explain how the expected blowdowns corresponding to these ring settings were extrapolated or calculated from test data.

   Response: Refer to Section C2.3, Appendix A.

8. Provide assurance that the safety valves will pass their rated flow at the plant ring settings and that the valves will perform and operate acceptably under the expected backpressures and blowdowns.

   Response: Refer to Section B4.5, C1.4, C1.5.

9. If the expected blowdowns exceed the valve design values, then address the consequences of increased blowdown, such as a rise in pressurizer water level and possible inadequate core cooling.

   Response: Refer to Appendix A.

10. Provide a comparison of the inlet pressure drop for the test and the plant.

    Response: Refer to Section C1.3.

11. Show that a bending moment sufficient in magnitude to account for discharge loads and thermal expansion of the pressurizer tank and inlet piping was applied during operability tests.

    Response: Refer to Section C1.7, C2.2.

CEN-301(A)

ARKANSAS POWER AND LIGHT COMPANY

ARKANSAS NUCLEAR ONE - UNIT 2
PRESSURIZER SAFETY VALVE
OPERABILITY REPORT

Nuclear Power Systems Division

April 1985

C-E POWER SYSTEMS
COMBUSTION ENGINEERING, INC.

Arkansas Nuclear One - Unit 2

Pressurizer Safety Valve

Operability Report

TABLE OF CONTENTS

Section		Page
PART A	INTRODUCTION	60
1.0	OBJECTIVE	61
2.0	BACKGROUND	61
3.0	APPROACH	62
	3.1 Introduction	62
	3.2 Selection of Applicable Tests and Analysis	62
	3.3 Plant-Specific Evaluation	63
4.0	SUMMARY	64
5.0	CONCLUSION	65
6.0	REFERENCES	66

TABLE OF CONTENTS (Cont'd)

Section		Page
PART B	EPRI TEST PROGRAM DESCRIPTION AND TEST DATA EVALUATION	68
1.0	EPRI SAFETY VALVE TEST PROGRAM	69
	1.1 Valve Selection Justification	69
	1.2 Test Conditions Justification	71
	1.3 Test Facility Description	71
	1.3.1 Introduction	71
	1.3.2 Test Loop Layout	71
	1.3.3 Instrumentation	75
	1.4 Testing Procedure	75
2.0	CROSBY SAFETY VALVES - GENERIC INFORMATION	76
	2.1 Description	76
	2.2 Nomenclature	79
3.0	APPROACH USED IN EVALUATION OF TEST DATA	82
	3.1 Introduction	82
	3.2 Blowdown	84
	3.3 Valve Discharge Flange Bending Moments	85
	3.4 Valve Operating Characteristics	85
	3.5 Acoustic Wave Amplitude	88
	3.5.1 Introduction	88
	3.5.2 Method of Calculation	89

TABLE OF CONTENTS (Cont'd)

Section		Page
4.0	CROSBY MODEL HB-BP-86 6M6 TEST RESULTS AND EVALUATION	91
	4.1 Introduction	91
	4.2 Inlet Piping Arrangement	91
	4.3 Test Conditions	91
	4.4 Test Results	95
	4.4.1 Introduction	95
	4.4.2 Long Inlet Configuration Tests	95
	4.4.2.1 Tests with (-136, -68) Ring Settings	95
	4.4.2.2 Tests with (-44, -66) Ring Settings	96
	4.4.2.3 Tests with (-186, -68) Ring Settings	97
	4.4.2.4 Tests with (-71, -18) and (-77, -18) Ring Settings	97
	4.4.3 Valve Inspection	98
	4.4.4 Valve Discharge Flange Bending Moment	98
	4.5 Evaluation of Test Results	99
PART C	ARKANSAS NUCLEAR ONE UNIT 2 PRESSURIZER SAFETY VALVE OPERABILITY - PLANT-SPECIFIC EVALUATION	102
1.0	GENERIC AND PLANT-SPECIFIC INFORMATION	103
	1.1 Introduction	103
	1.2 Inlet Fluid Conditions	103

TABLE OF CONTENTS (Cont'd)

Section		Page
1.3	Inlet Transient Pressure Drop	104
1.4	Safety Valve Flow Model	107
1.5	Back Pressure	107
1.6	Blowdown	110
1.7	Valve Discharge Flange Bending Moment	111
2.0	OPERABILITY EVALUATION	111
2.1	Safety Valves and Installation	111
2.2	Applicability of Tests	111
2.3	Evaluation	114
2.3.1	Tests with (-136, -68) Ring Settings	114
2.3.2	Tests with (-44, -66) Ring Settings	115
2.3.3	Tests with (-186, -68) Ring Settings	115
2.3.4	Tests with (-71, -18) and (-77, -18) Ring Settings	116
2.4	Conclusion	117
Appendix A	Justification for Increased Arkansas Nuclear One Unit 2 Safety Valve Blowdown	118

LIST OF TABLES

		Page
B1-1	EPRI Test Program. Selected Safety Valves, Valves Represented, Valve Distribution in EPRI Program Participants.	70
B4-1	Crosby HB-BP-86 6M6 Test Safety Valve Parameters	92
B4-2	Summary of Tests for Crosby Model HB-BP-86 6M6	94

LIST OF FIGURES

B1-1	Test Loop Schematic Showing Major Components	73
B1-2	Piping and Instrumentation Drawing	74
B2-1	Test Valve Schematic, Crosby Safety Valve, Model HB-BP-86 6M6	77
B2-2	Valve Nozzle Cross Section (typical)	81
B2-3	Representation of Typical Safety Valve Stem Position as a Function of Time	83
B3-1	Crosby HB-BP-86 6M6 Valve Operating Characteristics	87
B4-1	Long (loop seal) Inlet Piping Configuration for Crosby HB-BP-86 6M6 Safety Valve Test Series 900 and 1400	93
B4-2	Crosby HP-BP-86 6M6 Safety Valve Blowdown versus Upper Ring Setting	100

LIST OF FIGURES (Cont'd)

		Page
B4-3	Crosby HB-BP-86 6M6 Safety Valve Blowdown versus Peak Back Pressure	101
C1-1	Arkansas Nuclear One Unit 2 Pressurizer Safety Valve Flow Model Used in the Chapter 15 Safety Analyses.	108
C1-2	Comparison of the Arkansas Nuclear One Unit 2 Safety Valve Flow Model and used in Safety Analyses Crosby HB-BP-86 6M6 Valve Operating Characteristics Observed in EPRI Tests.	109
C2-1	Arkansas Nuclear One Unit 2 Pressurizer Safety Valve Inlet Piping Configuration.	112

PART A - INTRODUCTION

PART A - INTRODUCTION

1.0 OBJECTIVE

The objective of this report is to provide a detailed evaluation demonstrating the operability of the as-installed pressurizer safety valves in Arkansas Nuclear One - Unit 2. The evaluation is based on applying results from the EPRI Safety and Relief Valve Test Program. The test program is described in Part B of this report, and the plant-specific safety valve operability evaluation is discussed in Part C.

2.0 BACKGROUND

In the aftermath of the Three Mile Island (TMI) accident, the Nuclear Regulatory Commission issued requirements that utilities operating and constructing pressurized water reactor (PWR) power plants demonstrate the operability of pressurizer safety and relief valves and the structural adequacy of the discharge piping and supports. These requirements were promulgated in NUREG-0578 (Reference 6.7) and NUREG-0660 (Reference 6.8), and further clarified in NUREG-0737 (Reference 6.9). At the request of utilities with PWRs, EPRI developed and implemented a generic test program for pressurizer power operated relief valves and safety valves (Reference 6.10) which was accomplished during 1980-81. The testing of safety valves, as one phase of the test program, was implemented at a test facility at the Windsor, Connecticut, site of Combustion Engineering, Inc. The facility was specifically erected for the safety valve tests. The portion of the EPRI Valve Test Program performed at the C-E site is herein designated as the EPRI Safety Valve Test Program.

3.0 APPROACH

3.1 INTRODUCTION

The approach applied in this evaluation consisted of selecting tests most closely matching the Arkansas Nuclear One Unit 2 conditions and then applying the test results to the plant-specific evaluation. The approach, although generally the same as was used in Reference 6.12, was modified slightly because of Arkansas specific requirements and conditions.

A Crosby HB-BP-86 6M6 safety valve, the same valve model as installed in Arkansas Nuclear One Unit 2, was tested in the EPRI program. The test condition variables included valve inlet piping configurations, inlet fluid conditions, valve adjusting ring settings, discharge (back) pressure buildup, and inlet pressurization rates. The overall approach was as follows:

3.2 SELECTION OF APPLICABLE TESTS AND ANALYSIS

Since the Arkansas Nuclear One Unit 2 safety valves are specified for operation on steam conditions, only steam tests and the steam portion of steam-to-water transition tests were considered to be applicable.[1]

Out of the applicable tests, only tests exhibiting stable valve performance were further considered.

Valve characteristics were developed and analyzed based on test data.

---

1 In steam-to-water transition tests, the first cycle of opening occurred on steam and was considered to be applicable for purposes of evaluating opening stability.

3.3 PLANT-SPECIFIC EVALUATION

The following approach was applied to show that the Arkansas Nuclear One Unit 2 pressurizer safety valves were enveloped by a number of tests which resulted in acceptable valve operation.

The plant safety valve inlet piping configurations and the most limiting pressurization transients with the highest peak pressurizer pressure and pressurization rate were identified.

Tests that were directly applicable to the plant were identified based on the following:

- The valve stem reached a full flow position at opening.[1]
- The test valve inlet piping configuration is more limiting than that of the plant, based on calculated values of acoustic wave amplitudes. [2]

Directly applicable tests which resulted in reasonable blowdowns were then identified as tests which qualify the safety valve adjusting ring settings as being suitable for proper operation. Acceptable blowdown was determined by analysis of RCS pressure transients considering the response of pressurizer level and the effect of depressurization on loop subcooling.

---

[1] See Subsection 2.2, Part B, for definition

[2] See Subsection 3.5, Part B, for discussion

4.0 SUMMARY

In this report, results from the EPRI Safety Valve Test Program are applied to the Arkansas Nuclear One Unit 2 safety valves. Safety valve operability is demonstrated on a plant-specific basis using the following criteria:

1. The safety valve model tested in the EPRI program is representative of the valves installed in the plant.

2. Based on an analysis of acoustic wave amplitudes, the plant valve inlet piping configuration is shown to enhance the stability of valve operation relative to the EPRI test configuration.

3. The range of valve inlet fluid conditions used in the testing either envelopes or approximates the corresponding conditions estimated for the plant.

4. The valve stem lift measured in the tests is greater than or equal to full flow lift.

5. The maximum calculated bending moment at the plant valve discharge flange is lower than the maximum measured value for the test valve.

6. The plant-specific range of back pressures is enveloped by a range of back pressures measured in the tests.

7. The blowdown measured during testing for a given ring setting is less than the analyzed blowdown which prevents pressurizer level from reaching the safety valve inlet nozzle and also maintains an adequate margin of RCS subcooling.

Provided the above criteria are met, and the test valve exhibited stable operation, the plant-specific safety valve installation and valve adjustments are considered satisfactory.

5.0 CONCLUSION

The EPRI Safety Valve Test Program results, in conjunction with the Part C evaluation, identify the valve adjusting ring settings which are qualified for use at Arkansas Nuclear One - Unit 2. They are (-71, -18)[1], (-77, -18) and (-136, -68). These ring settings are qualified for use in Arkansas Nuclear One - Unit 2 since stable operation was demonstrated, test conditions bounded the conditions in the plant, adequate valve lift was achieved, the resultant blowdowns are acceptable, and bending moments imposed by the discharge piping did not impair valve operability.

Of these qualified ring settings, the (-71, -18) ring setting is optimum for use in Arkansas Nuclear One-Unit 2.

The (-71, -18) and (-77, -18) ring settings resulted in blowdowns less than that measured during testing of the (-136, -68) ring settings. Since a lower blowdown is desirable for the Arkansas Nuclear One - Unit 2 plant, the (-71, -18) and (-77, -18) ring settings are preferred over the (-136, -68) ring setting. Also, because during testing the (-77, -18) ring setting was intended to be the same as the (-71, -18) setting, and in order to select a single ring setting for the Arkansas Nuclear One - Unit 2 plant, the (-71, -18) ring setting is recommended, and is used in Arkansas Nuclear One - Unit 2.

---

[1] Crosby ring settings are designated in the order of upper and lower ring positions. The settings are expressed relative to the "level position". See Subsection 2.1, Part B.

6.0 REFERENCES

The following are references used throughout this report.

6.1 EPRI/C-E Safety Valve Test Report, EPRI NP-2770-LD, Project V102-2, Interim Report, January 1983.

6.2 Valve Inlet Fluid Conditions for Pressurizer Safety and Relief Valves in C-E Designed Plants, EPRI NP-2318-LD, Project V102-20, Interim Report, April 1982.

6.3 PWR Safety and Relief Valve Test Program, Valve Selection/ Justification Report, EPRI NP-2292-LD, Project V102, Interim Report, March 1982.

6.4 Flow of Fluids through Valves, Fittings, and Pipe by Crane, Technical Paper No. 410.

6.5 ASME Code, Section 111, Subsection NB-7700.

6.6 Terminology for Pressure Relief Devices - American National Standard ANSI B95.1 - 1977.

6.7 NUREG-0578, TMI-2 Lessons Learned Task Force Status Report and Short Term Recommendations, Nuclear Regulatory Commission, July 1979.

6.8 NUREG-0660, Nuclear Regulatory Commission Action Plan Developed as a Result of the TMI-2 Accident, May 1980.

6.9 NUREG-0737, Clarification of TMI Action Plan Requirements, Nuclear Regulatory Commission, November 1980.

6.10 Program Plan for the Performance Testing of PWR Safety and Relief Valves, Revision 1, July 1980, by Electric Power Research Institute, Nuclear Power Division.

6.11 Installation, Operating and Maintenance, Instruction No. I-1105-2 for Crosby Style HB and HB-BP Self-Actuated Nozzle Type Safety-Relief Valves, Crosby Valve & Gage Company, 2/73.

6.12 Summary Report on the Operability of Pressurizer Safety Valves in C-E Designed Plants, Prepared for the C-E Owners Group, Combustion Engineering CEN-227, December 1982.

6.13 EPRI PWR Safety and Relief Valve Test Program Guide for Application of Valve Test Program Results to Plant-Specific Evaluations, Interim Report, March 1982.

PART B - EPRI TEST PROGRAM DESCRIPTION AND TEST DATA EVALUATION

PART B - EPRI TEST PROGRAM DESCRIPTION
AND TEST DATA EVALUATION

1.0 EPRI SAFETY VALVE TEST PROGRAM

1.1 VALVE SELECTION JUSTIFICATION

NUREG-0737 required that testing be performed on full-scale pressurizer safety and relief valves representative of those in use or planned for use in PWRs. To obtain the valve operability data for the large variety of valves used in domestic PWR plants it was necessary for EPRI to select a limited, but fully representative set of valves for test purposes.

In order to select the test valves, a complete list of valve types, models, and sizes used or intended for use in PWR plants was compiled based on information provided by the NSSS vendors, valve manufacturers and PWR utilities. From these lists, valves were selected for testing which were considered to adequately represent the total PWR valve population. Justification that the test valve results are applicable to all plant/vendor valves was developed based on evaluations performed by the valve manufacturers. These evaluations considered the effects of differences in valve operating characteristics, materials, design details, orifice sizes and manufacturing processes on valve operability.

Table B1-1[1] provides a list of the selected test safety valves, the valves represented, and the valve distribution in PWR plants. As it can be seen from the table, a Crosby HB-BP-86 6M6 safety valve, the same valve model as used in Arkansas Nuclear One Unit 2, was tested in the Program. This makes the tested valve model directly applicable to the plant-specific evaluation.

Detailed documentation justifying the selection of valves for the tests is provided in Reference 6.3

---

[1] From Reference 6.3.

TABLE B1-1

EPRI TEST PROGRAM

SELECTED SAFETY VALVES, VALES REPRESENTED, VALVE DISTRIBUTION IN EPRI PROGRAM PARTICIPANTS

Valve Manufacturer	Selected Test Valves				Valves Represented				No. of Plants
	Model No.	Inlet	Size Orifice	Outlet	Model No.	Inlet	Size Orifice	Outlet	
Crosby Valve & Gage Company	HB-BP-86	3	K	6	HB-BP-86	3	K	6(smallest)	3
		6	M	6		3	K2	6	2
		6	N	8		4	K2	6	6
						6	K2	6	2
						4	M1	6	3
						6	M1	6	6
						4	M	6	1
						6	M	6	38
						6	N	8(largest)	6
Dresser Industries	31739A	2.5	No. 3	6	31709KA	2.5	K	6(smallest)	1
	31709NA	6	N	8	31739A	2.5	No. 3	6	11
					31749A	3	No. 4	6	3
					31759A	3	No. 5	6	5
					31709NA	6	N	8(largest)	17
Target Rock Corp.	69C	6	$3.513 in^2$	6	69C	6	$3.513 in^2$	6	1
								Total	105

Note: Inlet and outlet sizes are nominal pipe sized in inches

1.2 TEST CONDITIONS JUSTIFICATION

The basis for the selection of the test conditions for the EPRI Safety Valve Test Program is described in detail in Reference 6.2. FSAR/Reload analyses were reviewed to identify the valve inlet fluid conditions resulting from pressurization transients which actuate safety valves. The fluid conditions identified were peak pressurizer pressure, pressurization rate at actuation, temperature, and fluid state.

As presented in Reference 6.2, the safety valve inlet fluid state for Arkansas Nuclear One Unit 2 (as well as for all other C-E plants) transients initiated at normal power conditions would be saturated steam. For this reason only steam tests and the steam portion of steam-to-water transition tests were considered in this report.

1.3 TEST FACILITY DESCRIPTION

1.3.1 Introduction

The test facility for the EPRI Safety Valve Test Program is located at C-E's Kreisinger Development Laboratory in Windsor, Connecticut. Reference 6.1 provides a detailed description of the facility. A summary description is provided below.

1.3.2 Test Loop Layout

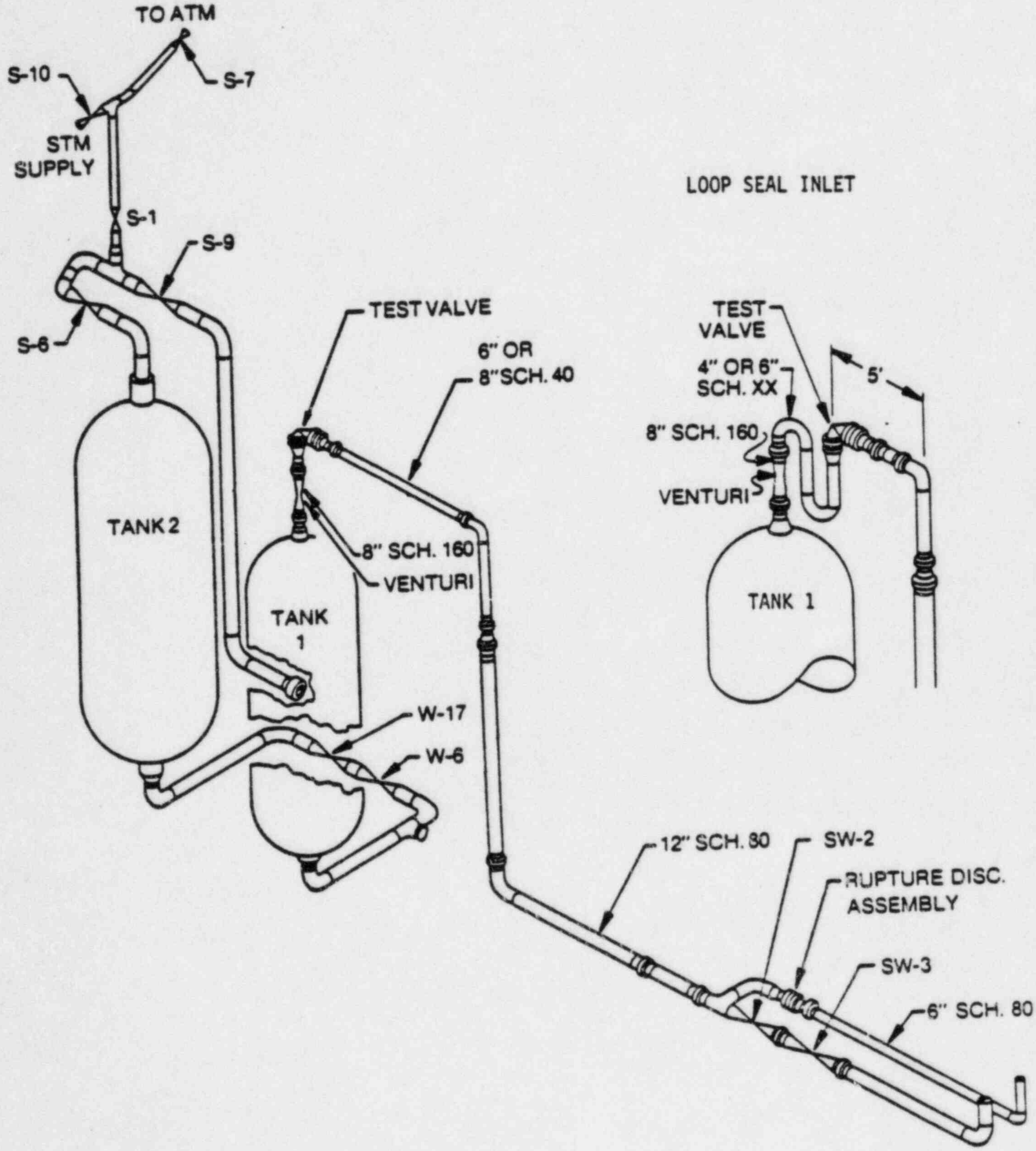
The major components, piping, and valves in the test system are shown in Figure B1-1. The system is capable of developing steam, water, and transition (steam-to-water) conditions at pressures up to 3000 psia. Design flow rates of the loop are 150,000 lb/hr steam continuously or 600,000 lb/hr for approximately 15 seconds and 5,500 gpm of water for approximately 15 seconds.

As shown in Figure B1-1, a test valve is mounted on top of Tank 1 with discharge to atmosphere through 6 inch or 8 inch (depending on the test valve) piping that is connected to 12 inch piping and valves. Tank 1 serves as a surge vessel in which the water and/or

steam inventory simulates the thermal-hydraulic conditions in a PWR pressurizer. Tank 2 serves as a driver vessel through expansion or evaporation of its fluid contents. The tanks are interconnected by two 12 inch lines each containing a fast closing and tight shutoff valve. Steam is supplied to the facility through a 6 inch line from a boiler. A recirculation system is provided for each tank as well as a method for controlling loop pressure by venting steam to atmosphere. Means were provided to adjust back pressure buildup (up to 1000 psig). A line containing a rupture disk is provided to prevent overpressurization of the discharge piping should the leak check isolation valve, SW-2, be inadvertently left closed during a test. Considerable flexibility has been built into the test loop to allow testing of different valve sizes and inlet piping configurations.

In order to simulate the different inlet piping arrangements found in PWR plants, two generic inlet piping configurations were developed. These configurations consisted of a short vertical inlet configuration and a long inlet/loop seal configuration. In addition, one test series (1200 series with the Crosby Model HB-BP-86, 6N8 valve) was performed with an intermediate length vertical inlet configuration.

Figure B1-1. Test Loop Schematic Showing Major Components



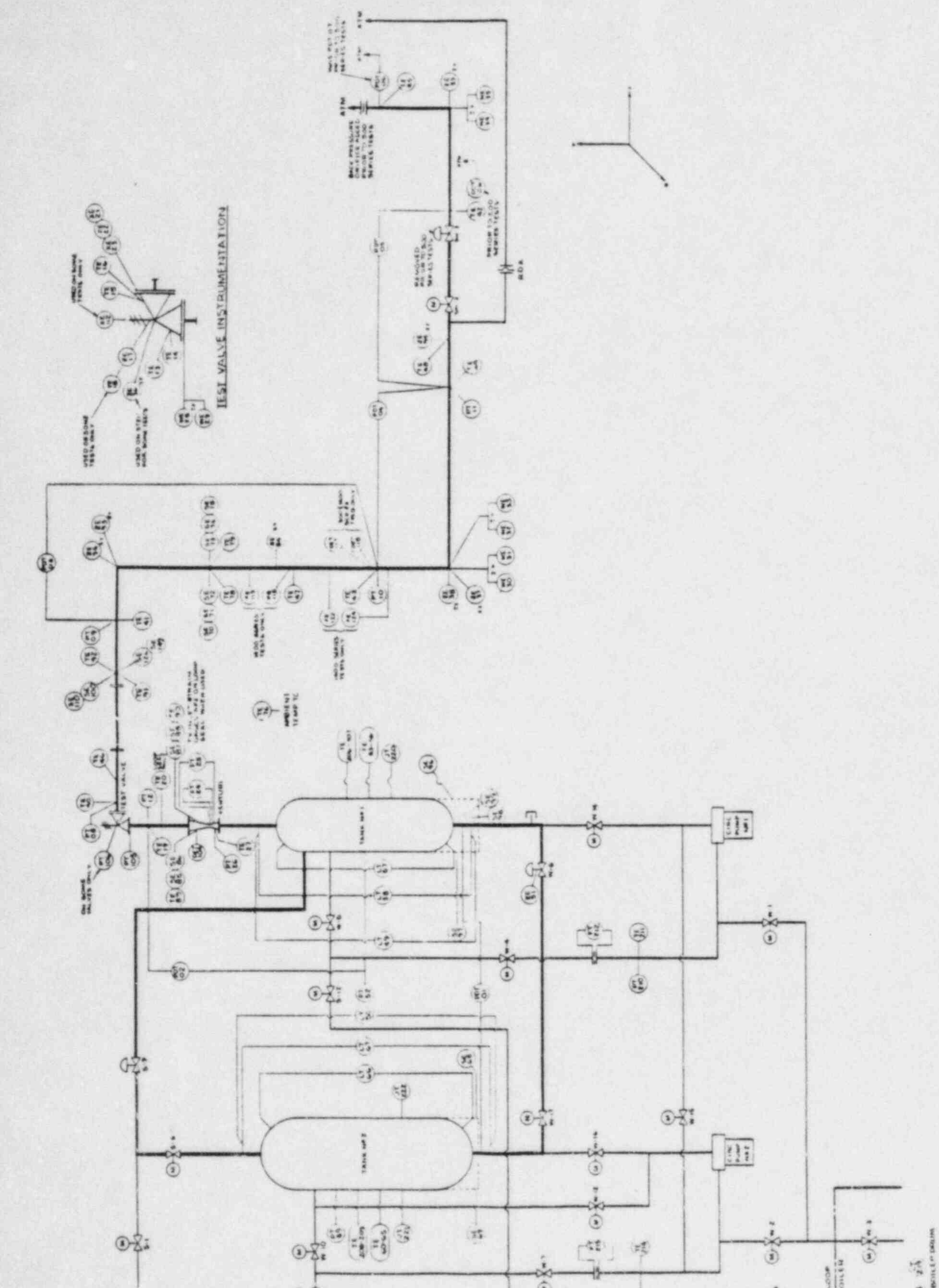


FIGURE B1-2. Piping and Instrumentation Drawing

1.3.3 Instrumentation

A full range of test instrumentation is provided in the facility. The location of the instrumentation is shown in Figure B1-2[1] In addition, process instruments were provided to assist the operator in controlling the test loop. A detailed description of the instrumentation is provided in Reference 6.1.

1.4 TESTING PROCEDURE

The general test procedure involved raising the pressure at a prescribed rate in order to actuate the test valve, starting from a valve inlet pressure below the valve opening setpoint.

The installed instrumentation recorded the valve behavior as it lifted, discharged, and closed. For each valve tested, runs were made with different valve adjusting ring settings, pressurization rates, back pressures, and inlet fluid conditions. The inlet fluid conditions tested were steam, water, and steam-to-water transition. The detailed procedure varied, depending upon the inlet fluid conditions being tested.

A valve leakage check was run prior and subsequent to each valve lift test. Safety valve opening set points were checked frequently throughout the test. The method of controlling the inlet conditions to the test valve is summarized below for each test type.

In the case of a steam test with a high pressurization rate, Tanks 1 and 2 were filled with steam and isolated from each other. Tank 1 pressure was above 2300 psia while Tank 2 was at about 2950 psia. Valve lift was initiated by opening the isolation valve between the tanks.

---

(1) From Reference 6.1, Vol. 2.

For steam tests with low pressurization rate, Tank 1 was isolated from Tank 2, and filled with steam at about 2300 psia. Steam from the boiler was fed to Tank 1 to raise pressure at the desired low ramp rate to lift the valve.

For steam-to-water transition tests, Tanks 1 and 2 were partially filled with saturated water at 2300 psia. The isolation valve between the tanks was in the open position. Boiler steam was fed to Tank 2 to raise the pressure to lift the safety valve on steam. Safety valve lift resulted in the flow of water from Tank 2 to Tank 1. Eventually, Tank 1 filled with water and the safety valve inlet fluid changed from steam to water.

2.0 CROSBY SAFETY VALVES - GENERIC INFORMATION

2.1 DESCRIPTION

The Crosby HB-BP-86 6M6 safety valve is a direct-acting spring loaded safety valve designed for use in PWR plants as a pressure relief device (Figure B2-1).

Crosby valves have two major adjustments for safety valve operation. The first is the set pressure adjustment. The valve set pressure is established by turning the adjusting bolt clockwise to increase set pressure, or counterclockwise to decrease set pressure.

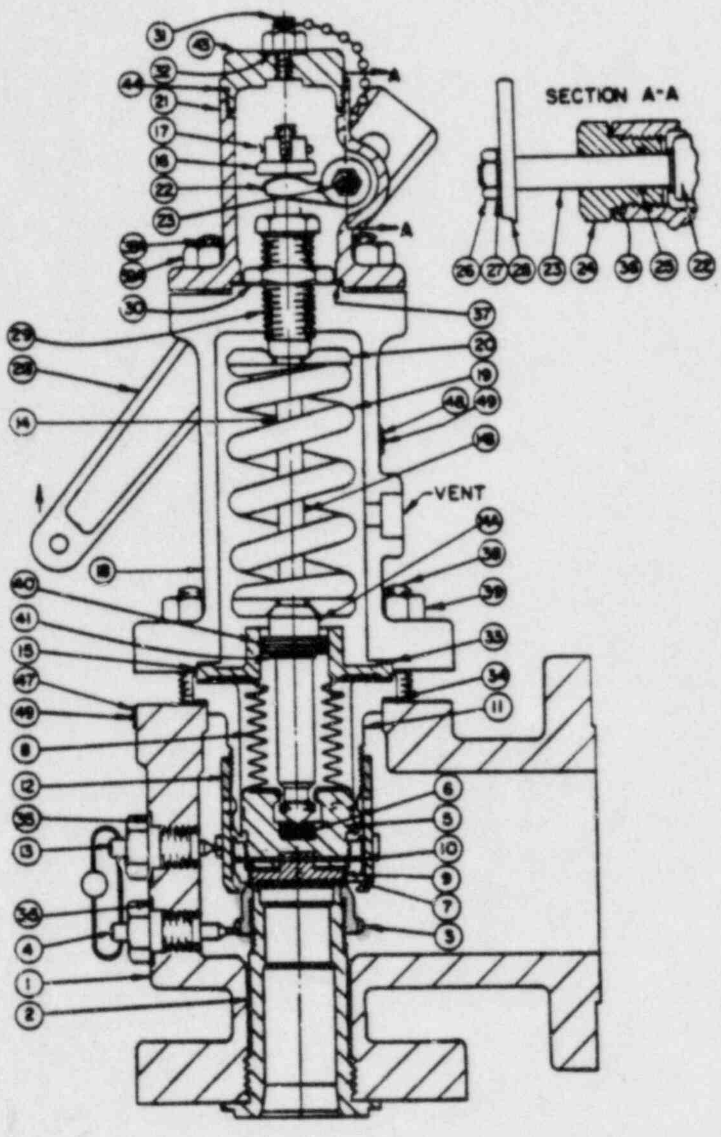


Figure B2-1 Test Valve Schematic, Crosby Safety Valve, Model HB-BP-86 6M6

PIECE NO.	PART NAME	PIECE NO.	PART NAME
1	BODY	28	LEVER
2	NOZZLE	29	ADJUSTING BOLT
3	NOZZLE RING	30	ADJUSTING BOLT NUT
4	NOZZLE RING SET SCREW	31	CAP PLUG
5	DISC HOLDER	32	CAP PLUG GASKET
6	DISC BUSHING	33	BONNET ADAPTER GASKET
7	DISC RING	34	EDUCTOR GASKET
8	BELLOWS	35	NOZZLE RING AND ADJUSTING
9	DISC INSERT		RING SET SCREW GASKET
10	DISC INSERT PIN	36	DOG SHAFT BEARING GASKET
11	EDUCTOR	37	CAP GASKET
12	ADJUSTING RING	38	BONNET STUD
13	ADJUSTING RING SET	38A	CAP STUD
	SCREW	39	BONNET STUD NUT
14	SPINDLE ASSEMBLY	39A	CAP STUD NUT
14B	SPINDLE ROD	40	PISTON
15	BONNET ADAPTER	41	PISTON LOCKCLIP
16	SPINDLE NUT	42	GAG SCREW
17	SPINDLE NUT COTTER	43	GAG TOP
18	BONNET	44	CAP TOP GASKET
19	SPRING	45	CANOPY RING
20	SPRING WASHER	46	GASKET (SPECIAL)
21	CAP	47	NAMEPLATE AND IDENTI-
22	DOG		FICATION PLATE
23	DOG SHAFT	48	CAUTION PLATE
25	DOG SHAFT "O" RING	49	DRIVE SCREWS
26	DOG LEVER NUT		
27	DOG LEVER LOCKWASHER		

Figure B2-1 (Cont'd.)

The second major adjustment is accomplished through the valve adjusting rings. The two adjusting rings, termed upper (adjusting ring) and lower (nozzle ring), are mechanical devices incorporated in the valve to change the distribution of internal forces which control the valve lift and the valve closing pressure.

Positions of the rings are given in notches relative to the level position. The level position is the number of notches relative to the upper limit of ring travel for which the bottom of the upper ring is flush with the bottom of the disc ring. Plant (field) settings for the upper ring are given notches relative to the "highest-locked position" which is the upper limit of ring travel. For the lower ring the "highest-locked position" coincides with the level position; therefore, both plant and test settings are directly comparable.

2.2 NOMENCLATURE

The following definitions of terms are based on Reference 6.6 except where noted otherwise.

2.2.1 Rated Lift - Design lift at which a valve attains its rated relieving capacity.

2.2.2 Discharge Area - Measured minimum net area which determines the flow through a valve.

2.2.3 Bore Area - Minimum cross-sectional area of a valve nozzle.

2.2.4 Curtain Area - Area of the cylindrical (of diameter D_c) or conical discharge opening created between the seating surfaces by the lift of the disc above the seat (see Figure B2-2).

2.2.5 [1]Full Flow Stem Position - Valve stem lift, at which curtain area becomes equal to bore area.

$$\text{Full flow stem position (full flow lift)} = \frac{\text{Bore Area}}{\pi \times D_c}$$

2.2.6 Valve Opening Pop Pressure - The value of increasing inlet static pressure at which the main disc moves in the opening direction at a faster rate as compared with corresponding movement at higher or lower pressures.

2.2.7 Reseating Pressure - The pressure at which the valve main disc reestablishes contact with the seat (reseats). The pressure is measured in Tank 1.

2.2.8 Chatter - Rapid reciprocating motion of the valve movable parts in which the disc contacts the seat.

2.2.9 Flutter - Rapid reciprocating motion of the valve movable parts in which the disc does not contact the seat.

2.2.10 [2]Stable Performance - The valve opens, remains open and closes without flutter and/or chatter.

2.2.11 Blowdown - The difference between actual popping pressure of a pressure relief valve and actual reseating pressure expressed as a percentage of set pressure or in pressure units (see Subsection 3.2 for additional clarification).

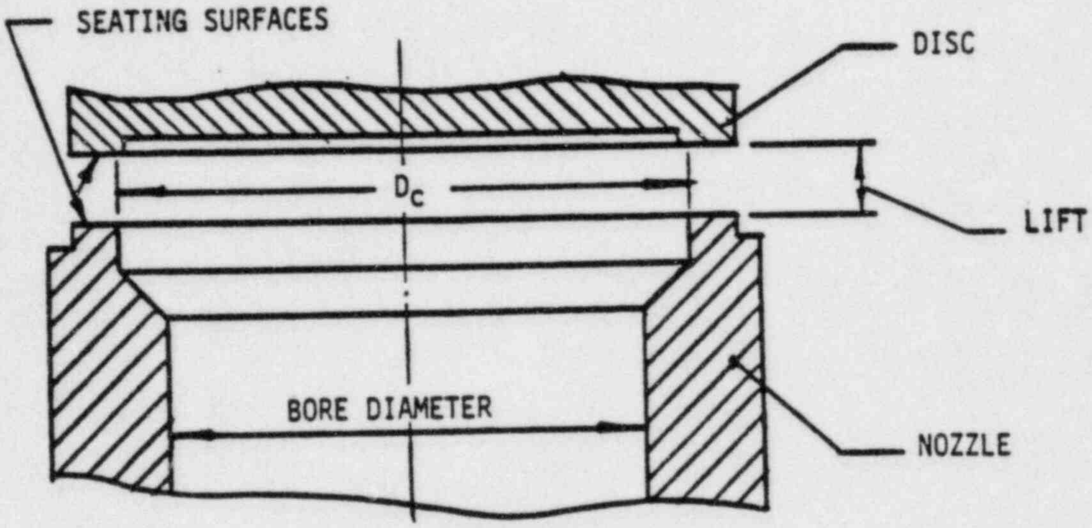
2.2.12 [2]Peak Back Pressure - The maximum sustained outlet pressure just downstream of the test valve which was observed during the test.

---

[1] Defined by Combustion Engineering Inc. for evaluation of the EPRI test results.

[2] Defined by EPRI during the test program.

Figure B2-2 Valve Nozzle
Cross Section (Typical)



2.2.13 [2]Opening Pop Time - The effective time for the valve stem to move from the closed position to the rated lift position. In cases where the pop starts from an intermediate lift and/or the valve does not reach rated lift, the slope of the stem position is extrapolated to give a pop time for the entire lift range. The pop time does not include the stem acceleration time which normally occurs at the beginning of the pop. This is included with the total simmer time (see Figure B2-3).

2.2.14 [2]Opening Simmer Time - The time elapsed between initial valve opening pressure and the valve pop pressure.

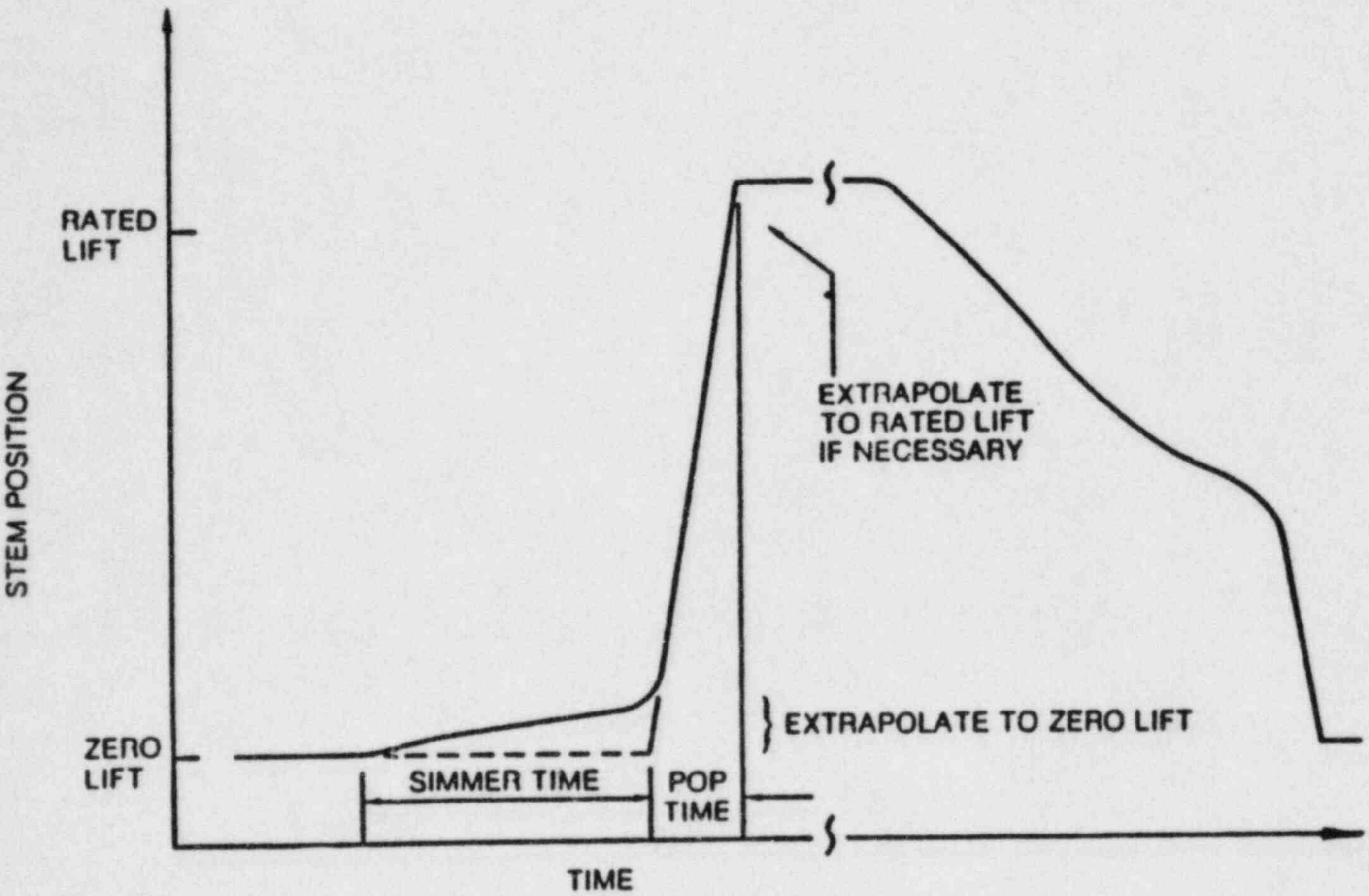
3.0 APPROACH USED IN EVALUATION OF TEST DATA

3.1 INTRODUCTION

Analysis of the EPRI test results revealed a number of factors affecting the performance of safety valves. The criteria for acceptable performance are: 1) stable valve operation, 2) full flow lift achieved, 3) reasonable blowdown results, and 4) valve operability is not affected by bending moments imposed by the discharge piping on the valve discharge flange. Factors that affected valve performance during the tests were valve adjusting ring settings, inlet piping configuration, peak back pressure and valve opening (pop) time.

Evaluation of the Crosby HB-BP-86 6M6 valve test results included establishing interrelationships between blowdown and peak back pressure, and, also, blowdown and adjusting ring settings, and developing valve operating characteristics. The approach used in evaluating each of these characteristics is described in this section.

Figure B2-3 **Representation of Typical Safety Valve Stem Position as a Function of Time.**



3.2 BLOWDOWN

Blowdown is the term used to describe the closing pressure of pressure relief valves. A standard definition of blowdown suggested by valve manufacturers is provided in Subsection 2.2. It should be noted that the EPRI test program (Reference 6.1) used a different interpretation of blowdown than is used by the valve manufacturers (Reference 6.6). The difference between the two methods is summarized below.

The EPRI version expresses blowdown in terms of design set pressure:

$$BD_{EPRI} = \frac{\text{Design Set Pressure - Actual Reseating Pressure}}{\text{Design Set Pressure}} \times 100\%$$

The manufacturers' version expresses blowdown in terms of actual opening pop pressure:

$$BD_{A} = \frac{\text{Actual Opening Pop Pressure - Actual Reseating Pressure}}{\text{Actual Opening Pop Pressure}} \times 100\%$$

Since most of the tests performed on the Crosby safety valve included a loop seal at the valve inlet the valve pop pressure was substantially higher than the initial opening pressure. A loop seal at the valve inlet delays valve popping until the loop seal has been discharged and steam can expand in the valve huddling chamber. This results in a higher calculated blowdown than if the valve were to open on steam fluid. Therefore this report uses the initial opening pressure to calculate blowdown since the Arkansas Nuclear One Unit 2 safety valves do not have a loop seal inlet.

The version expressing blowdown in terms of initial opening pressure:

$$BD_{o} = \frac{\text{Initial Opening Pressure - Actual Reseating Pressure}}{\text{Initial Opening Pressure}} \times 100\%$$

Each method of blowdown will be shown in the following section of the report for each test for comparative purposes. However, evaluation of the test results and plant-specific evaluation use only the "initial opening pressure" version.

3.3 VALVE DISCHARGE FLANGE BENDING MOMENTS

The induced bending moments at the valve discharge flange during opening and closing were measured in the EPRI program. The maximum bending moment measured during the steam tests of the Crosby HB-BP-86 6M6 valve is presented in the following section. It is compared to the moments expected in the plant in order to demonstrate valve operability.

3.4 VALVE OPERATING CHARACTERISTICS

The Crosby HB-BP-86 6M6 safety valve operating characteristics were developed based on test data. The Figure B3-1 curves relate valve discharge area to valve inlet pressure for blowdowns of 5, 10 and 15 percent. Since the curves for 5, 10 and 15 percent blowdown are identical except for being at different pressure levels these curves could be shifted to provide valve closing characteristics at blowdowns other than 5, 10 or 15 percent.

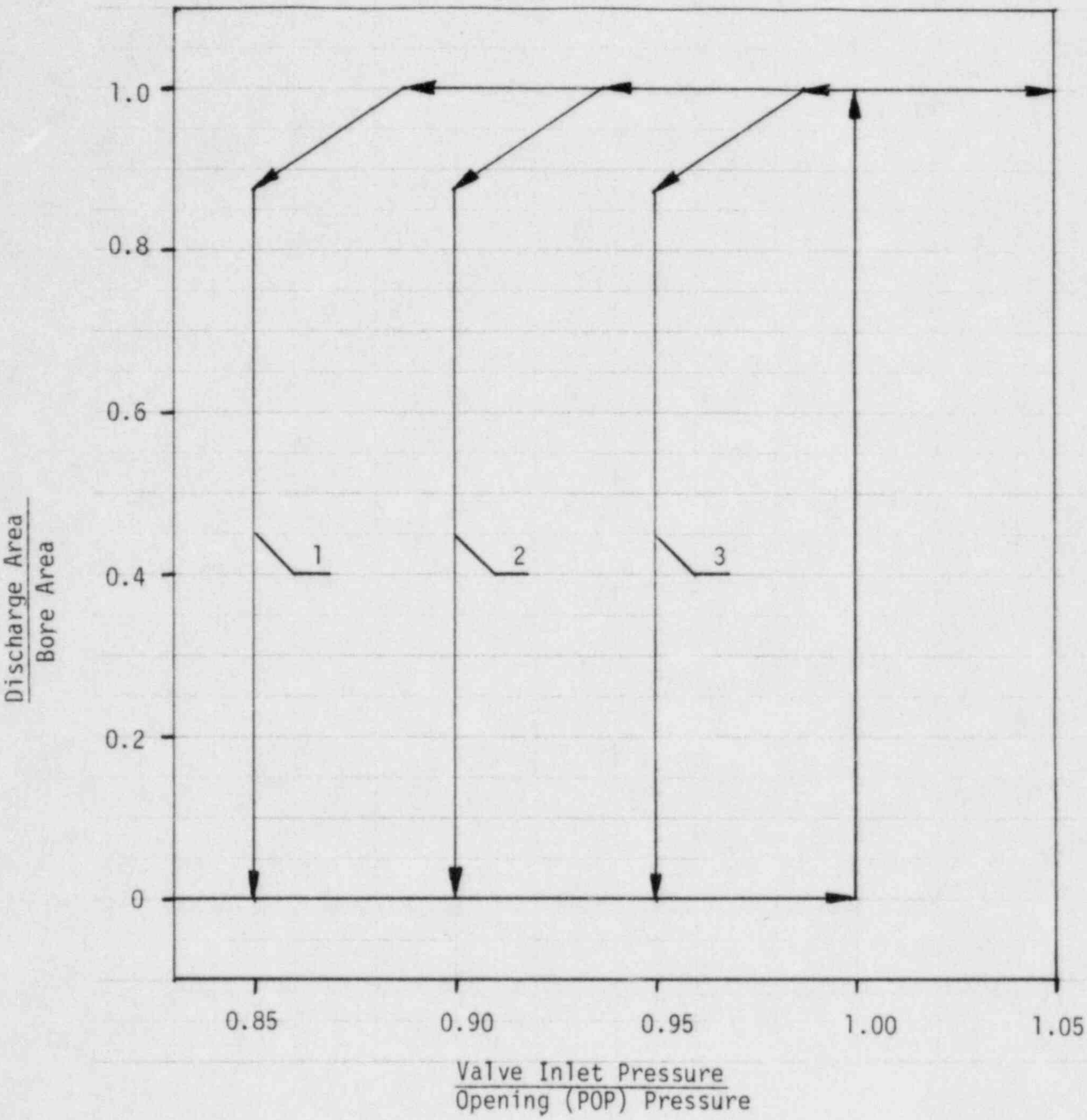
The operating characteristics were based on the following data plots taken from Reference 6.1:

- Valve Stem Position vs. Time (ZE17) or (ZE36) and,
- Tank 1 Pressure vs. Time (PT52).

It should be noted that, although the characteristics refer to the valve inlet pressure, Tank 1 pressure was used instead because of the higher accuracy of pressure measurements. Since there was no flow at valve opening and closing, Tank 1 pressure and valve inlet pressure in

each test were practically the same. In the intermediate stage of valve operation, because of losses in inlet piping, the pressures were slightly different but the difference is considered negligible for the purposes of this evaluation.

FIGURE B3-1 Crosby HB-BP-86 6M6 Valve Operating Characteristics



Notes: 1 - Operating characteristic observed in tests (at 15% blowdown)
2 - Operating characteristic observed in tests (at 10% blowdown)
3 - Operating characteristic observed in tests (at 5% blowdown)

The discharge area to bore area ratio characterizes the flow rate through a valve. Before the valve stem reaches a specific lift, termed full flow position, the area limiting the discharge is a curtain area which is smaller than the bore area (see Figure B2-2). When the valve stem is at the full flow position, the bore and the curtain area become equal. After the stem lifts above the full flow position, the bore area becomes the limiting discharge area, since it is smaller than the curtain area. Since the bore area is a constant for each valve model, further valve lift, beyond the point when

$$\frac{\text{Discharge Area}}{\text{Bore Area}} = 1$$

does not affect the discharge area. Accordingly, stem lift beyond the full flow position does not increase the flow rate. This hypothesis assumes that the valve discharge coefficient does not change once the full flow position is reached.

3.5 ACOUSTIC WAVE AMPLITUDE

3.5.1 Introduction

The combination of inlet piping configuration and valve opening pop time causes an inlet transient pressure drop at valve opening (lasting less than 0.1 seconds) that may lead to valve instability. This pressure drop is due to the acoustic expansion wave developed by the rapid valve opening. The wave propagates upstream to Tank 1 and returns back to the valve inlet as a compression wave. Valve instability may result if the depressurization at the inlet is large enough (i.e., greater than valve blowdown) and sustained long enough for the valve to react to the reduced force on the disc. Consequently, the acoustic wave amplitude is an important criterion in the application of the test results to plant-specific evaluations. The method of calculating acoustic wave amplitude during valve opening is provided below.

3.5.2 Method of Calculation

The inlet piping pressure drop due to acoustic wave propagation during valve opening can be calculated for both the EPRI test configuration and plant piping. Comparison of acoustic wave pressure drops for the tested and plant piping will determine if the tested configuration bounds the Arkansas Nuclear One Unit 2 piping configuration.

Reference 6.13 presents the method of calculating acoustic wave pressure drop. Two situations must be considered when calculating acoustic wave amplitude. These are:

- If $T_{op} \leq 2L/c$,

$$\Delta P_{AW} = \frac{cM}{g_c A}$$

- If $T_{op} > 2L/c$,

$$\Delta P_{AW} = \frac{2LM}{g_c A T_{op}}$$

where,

c = steam sonic velocity at nominal valve set pressure, at 2500 psia, c=1400 ft/sec.

L = inlet piping length (ft).

T_{op} = valve opening time for steam inlet conditions as established from the EPRI testing effort is 10 msec for Crosby safety valves.

ΔP_{AW} = acoustic wave amplitude (psi)

M = valve design flowrate for steam (design flow = $\frac{\text{rated flow}}{0.90}$ = 466,674 lb/hr)

g_c = gravitational constant $\left(32.2 \frac{lbm - ft}{lbf - sec^2}\right)$

A = inlet piping flow area (ft^2)

4.0 CROSBY MODEL HB-BP-86 6M6 TEST RESULTS AND EVALUATION

4.1 INTRODUCTION

The Crosby Model HB-BP-86 6M6 safety valve has a 6-inch inlet, 6-inch outlet, and 3.644 sq. in. bore area. The tests described below were conducted on valve serial number N56964-00-0086. Valve parameters are listed in the Table B4-1. A detailed description of the valve and the associated tests is provided in Reference 6.1, Volume 6.

4.2 INLET PIPING ARRANGEMENT

The Crosby HB-BP-86 6M6 valve was tested on a long inlet (test series 900 and 1400) piping configuration, shown in Figure B4-1.

4.3 TEST CONDITIONS

A total of 16 steam and steam-to-water transition tests were performed on the Crosby HB-BP-86 6M6 valve. All sixteen tests were conducted with a long inlet piping configuration. Table B4-2 provides the summary of the tests categorized according to valve adjusting ring settings. A detailed tabulation of the test data is provided in Reference 6.1, Vol. 6, Tables 4-2 thru 4-4. It should be noted that only steam conditions are applicable, as described in Part C.

All but 3 of the tests were initiated with a filled loop seal at the safety valve inlet. A total of 3 low flow transition tests were performed two of which had a filled loop seal at the valve inlet. The remaining tests were steam tests which were initiated at a high pressurization rates (283 to 375 psi/sec) except for one steam test which was initiated with a low pressurization rate (3.2 psi/sec) with a filled loop seal.

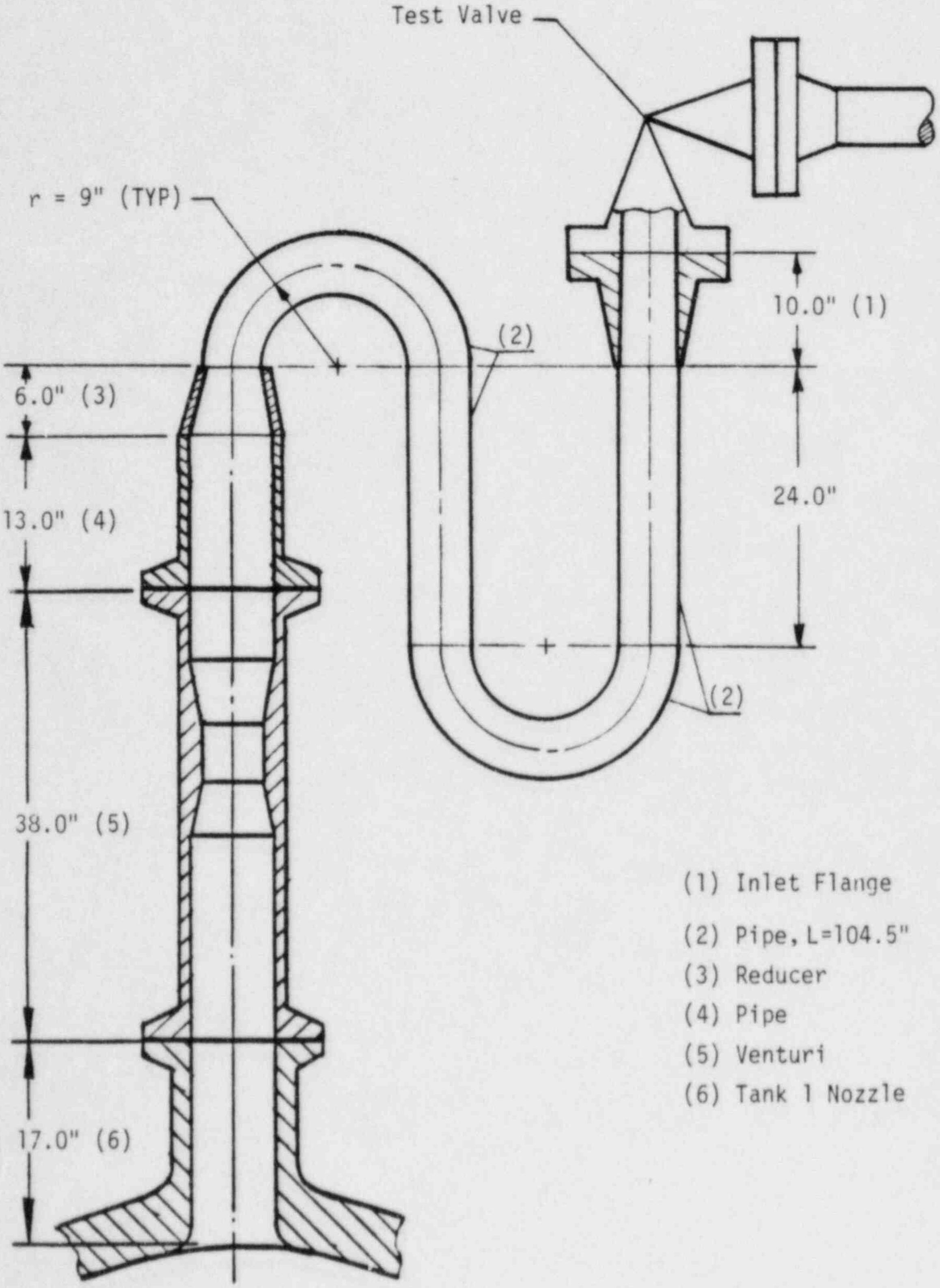
TABLE B4-1

CROSBY HB-BP-86 6M6 TEST SAFETY VALVE PARAMETERS

Manufacturer	Crosby Valve and Gage Company
Inlet Diameter, in.	6
Outlet Diameter, in.	6
Bore Area, in^2	3.644
Orifice Designation	M
Design Set Pressure, psig	2485
Design Blowdown, %	5
Rated Flow, lb/hr	420,006
Rated Lift, in.	0.538
Inlet Flange Rating, #ANSI	1500
Outlet Flange Rating, #ANSI	600
Curtain Diameter, in[1]	2.480
Full Flow Lift, in[1]	0.468

[1] See Subsection 2.2 for definition

Figure B4-1. Long (loop seal) Inlet Piping Configuration for Crosby HB-BP-86 6M6 Safety Valve. Test Series 900 and 1400.



		I.D., in.
(1)	Inlet Flange	4.897
(2)	Pipe, L=104.5"	4.897
(3)	Reducer	6.813/4.897
(4)	Pipe	6.813
(5)	Venturi	6.813
(6)	Tank 1 Nozzle	6.813

Table B4-2

Summary of Tests

For Crosby Model HB-BP-86 6M6 Valve

Valve Ring Settings Upper	Valve Ring Settings Lower	Test Type	Test No.	Inlet Piping Configuration	Pressure, psig Initial Opening	Pressure, psig Opening (pop)	Pressure, psig Reseating	BD_{EPRI}(1) %	BD_A(2) %	BD_0(3) %	Peak Tank 1 pressure, psia	Comments
-136	-68	Steam	903	long	2475	2481	2249	9.5	9.4	9.1	2667	(7)
		LS	906a	long	2567	2565	2279	8.3	11.2	11.2	2582	(6)(7)
		LS	908	long	2552	2672	2279	8.3	14.7	10.7	2688	(7)
		LS	910	long	2465	2613	2291	7.8	12.3	7.1	2634	
		LS	917	long	2443	2647	2261	9.0	14.6	7.4	2732	
		LS	920	long	2482	2680	(5)	(5)	(5)	(5)	2725	(9)
-44	-66	LS	913	long	2535	2719	2301	7.4	15.4	9.2	2735	
		LS Trans	914a	long	2495	2485	2294	7.7	7.7	8.1	2516	(6)(7)(8)
-186	-68	LS	923	long	2634	2717	2293	7.7	15.6	12.9	2736	(7)
		Trans	926a	long	2374	2374	2252	9.4	5.1	5.1	2389	(6)(7)
-71	-18	LS	929	long	2585	2702	2358	5.1	12.7	8.8	2726	(7)
		LS Trans	931a	long	2555	2560	2170	12.7	15.2	15.1	2578	(6)(7)(10)
-77	-18	LS	1406	long	2515	(4)	2251	9.4	(4)	10.5	2703	
		Steam	1411	long	2395	2405	2282	8.2	5.1	4.7	2664	
		LS	1415	long	2540	2740	2331	6.2	14.9	8.2	2760	
		LS	1419	long	2449	2659	(5)	(5)	(5)	(5)	2675	(9)

(1) Blowdown used in the EPRI program (Reference 6.1). See Subsection 3.2 for definition.
(2) Blowdown based on opening (pop) pressure. (See Subsection 3.2).
(3) Blowdown based on the initial valve opening pressure (See Subsection 3.2).
(4) Unstable condition precluded reliable measurement.
(5) The test was terminated when the valve was manually opened to stop chatter, interfering with this measurement.
(6) Test w/low pressurization rate (<4 psi/sec). All other tests are w/high rate (283 to 375 psi/sec).
(7) Test w/high peak back pressure (445 to 725 psia). All other tests are w/low peak back pressure (227 to 255 psia).
(8) The valve chattered on the final multiple actuation (chattered when opening on steam).
(9) The valve chattered on closure (closing on steam).
(10) The valve chattered during opening on the final actuation (opening on water) but then stabilized.

4.4 TEST RESULTS

4.4.1 Introduction

The Crosby test valve was tested with five different combinations of ring settings during steam and steam-to-water transition tests both with and without loop seals. These sixteen tests were all performed on a long inlet configuration. The valve exhibited stable performance when opening and closing on steam during all of the tests except for three of the tests where the valve chattered. The results of these tests are described below.

4.4.2 Long Inlet Configuration Tests

4.4.2.1 Tests with (-136, -68) Ring Settings

Six steam tests were performed with (-136, -68) ring settings. All but one of the steam tests were conducted with a filled loop seal. The tests were performed with both high and low pressurization rates and high and low back pressures.

As was discussed previously in Section 3.2 of Part B, blowdown was calculated using the initial opening pressures. Since a loop seal was used in most of the tests, valve pop was delayed from the initial valve opening until the loop seal was completely discharged. The time required for loop seal discharge resulted in valve pop pressures up to 200 psi higher than the initial opening pressure. In contrast, the pop pressure was within 10 psi of the initial valve opening pressure during tests where the valve opened on steam. Calculating valve blowdown using the pop pressure of loop seal tests would result in artificially high blowdowns for the Arkansas Nuclear One Unit 2 safety valves since Arkansas has no loop seals. Therefore the safety valve blowdown based on initial valve opening pressure will be most representative of blowdowns for the Arkansas safety valves.

For these tests, blowdowns ranged from 7.1 to 11.2% and averaged 9.1%. The initial valve opening pressures were between 1.7% below and 3.3% above the nominal safety valve setpoint. Opening pop time was between 8 and 17 msec.

Although the valve did not reach the rated lift during any of these tests, the full flow lift position was achieved in each test for which a reliable measurement was available. The valve not reaching rated lift position was attributed to the combination of stackup tolerances within the valve due to thermal expansion of internal parts. This resulted in a maximum lift less than the rated lift. The valve did reach rated flow during each of these tests.

Stable valve performance was exhibited during five of the six tests performed with (-136, -68) ring settings. Test 920 a loop seal, steam test chattered on valve closure. Test 920 was performed similarly to Test 917 in order to obtain repeatability data on piping loads. Test 917 exhibited stable valve performance with a blowdown of 7.4%.

4.4.2.2 Tests with (-44, -66) Ring Settings

Two tests, Tests 913 and 914, were performed with ring settings at (-44, -66). For Tests 913 and 914 the upper ring was in an unintended location. Test 913 was scheduled to be a repeat of Test 910. However, while setting up to do Test 913, the valve started to leak. The valve was disassembled to replace the disc insert and relap the nozzle seat. After reassembly, a procedural error resulted in an unintended change in the upper ring setting. Following Test 914, prior to disassembly, the ring locations were checked and the upper ring was found to have been left at -44 notches relative to the level position instead of -136 which was intended.

Test 913 was a high pressurization rate, low back pressure, loop seal steam test. Test 914 was a low flow transition test performed with high back pressure and with a loop seal.

Blowdown ranged from 8.1 to 9.2%. Initial opening pressure ranged from 0.4 to 2.0% above the safety valve design set pressure.

The valve exhibited stable performance in Test 913 and the first two actuations on steam in Test 914. However, on the third actuation on steam in Test 914 the valve began to chatter prior to the steam to water transition.

4.4.2.3 Tests with (-186, -68) Ring Settings

One high pressurization rate steam test with a loop seal and one steam-to-water transition test with a drained loop seal were performed with ring settings at (-186, -68). Both tests were performed with high back pressure.

Safety valve blowdown ranged from 5.1 to 12.9%. Initial opening pressures were 4.5% below and 6.0% above the safety valve design setpoint with opening pop times of 9 and 13 msec. The valve reached full flow lift position and rated flow during each test.

Stable valve performance was exhibited during both tests including steam-to-water transition Test 926 which had a total of 4 actuations.

4.4.2.4 Tests with (-71, -18) and (-77, -18) Ring Settings

The ring settings of (-71, -18) and (-77, -18) are typical of those used in PWR plants. Since there is only a difference of six notches between the upper ring position for the two ring settings, these two ring settings are essentially the same. The difference between these two ring settings was attributed to replacement of the bellows assembly during testing.

Five steam tests and one steam-to-water transition test were run with ring settings at (-71, -18) and (-77, -18). All except one of the steam tests were conducted with a loop seal at the safety valve inlet. All of the steam tests were performed with a high initial pressurization rate. The steam-to-water transition test was a low flow test. The tests were performed with high and low back pressures.

Blowdowns for the tests which closed on steam ranged from 4.7 to 10.5%. Initial valve opening pressures ranged from 3.6% below to 4.0% above the nominal safety valve setpoint. The valve reached full flow lift position and rated flow during each of these tests.

The test valve operated with stable performance during five of these six tests. The valve chattered during closing on steam in Test 1419. Test 1419, a high pressurization rate steam test with a filled loop seal and low back pressure, was a repeat of Test 1415 to obtain repeatability data. Test 1415 exhibited stable valve behavior with a blowdown of 8.2%.

4.4.3 Valve Inspection

Typical wear patterns on seat surfaces were observed during inspections performed after the steam tests. The seat surfaces were lapped prior to reassembly and continued testing to minimize seat leakage.

4.4.4 Valve Discharge Flange Bending Moment

The maximum bending moment of 298,750 in-lbs was measured in Test 908. The bending moment did not impair the operability of the valve.

4.5 EVALUATION OF TEST RESULTS

The plot of actual test data in Figure B4-2 demonstrates that blowdown increases as the upper ring is moved to a lower position. Figure B4-2 shows the highest blowdown measured for each of the various ring settings.

There appeared to be no direct correlation between the magnitude of back pressure and safety valve blowdown as illustrated in Figure B4-3. This result is similar to that observed for both smaller and larger Crosby safety valves, namely that blowdown does not depend strongly on back pressure.

Figure B4-2 - Crosby HB-BP-86 6M6 Safety Valve
Blowdown vs. Upper Ring Setting

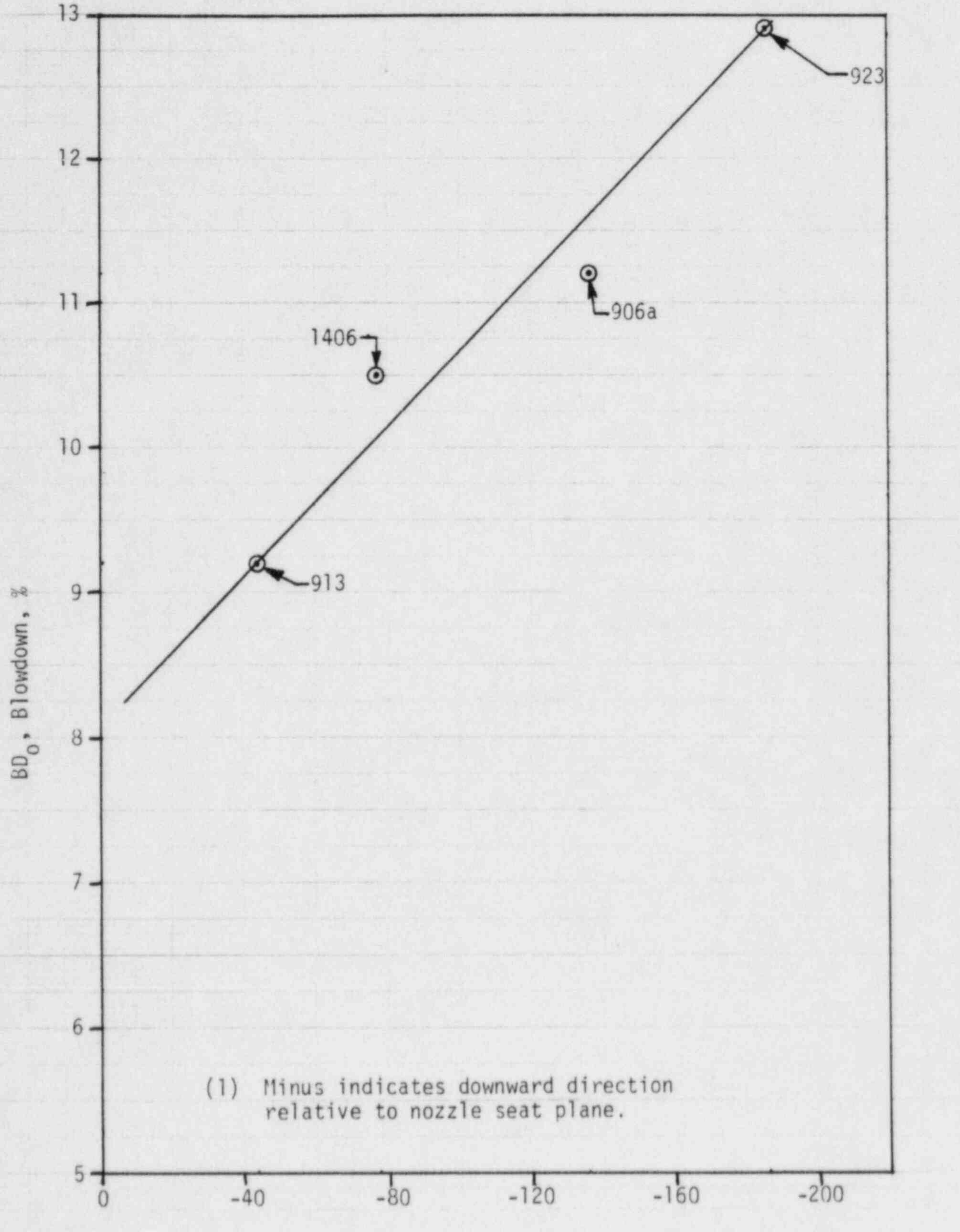
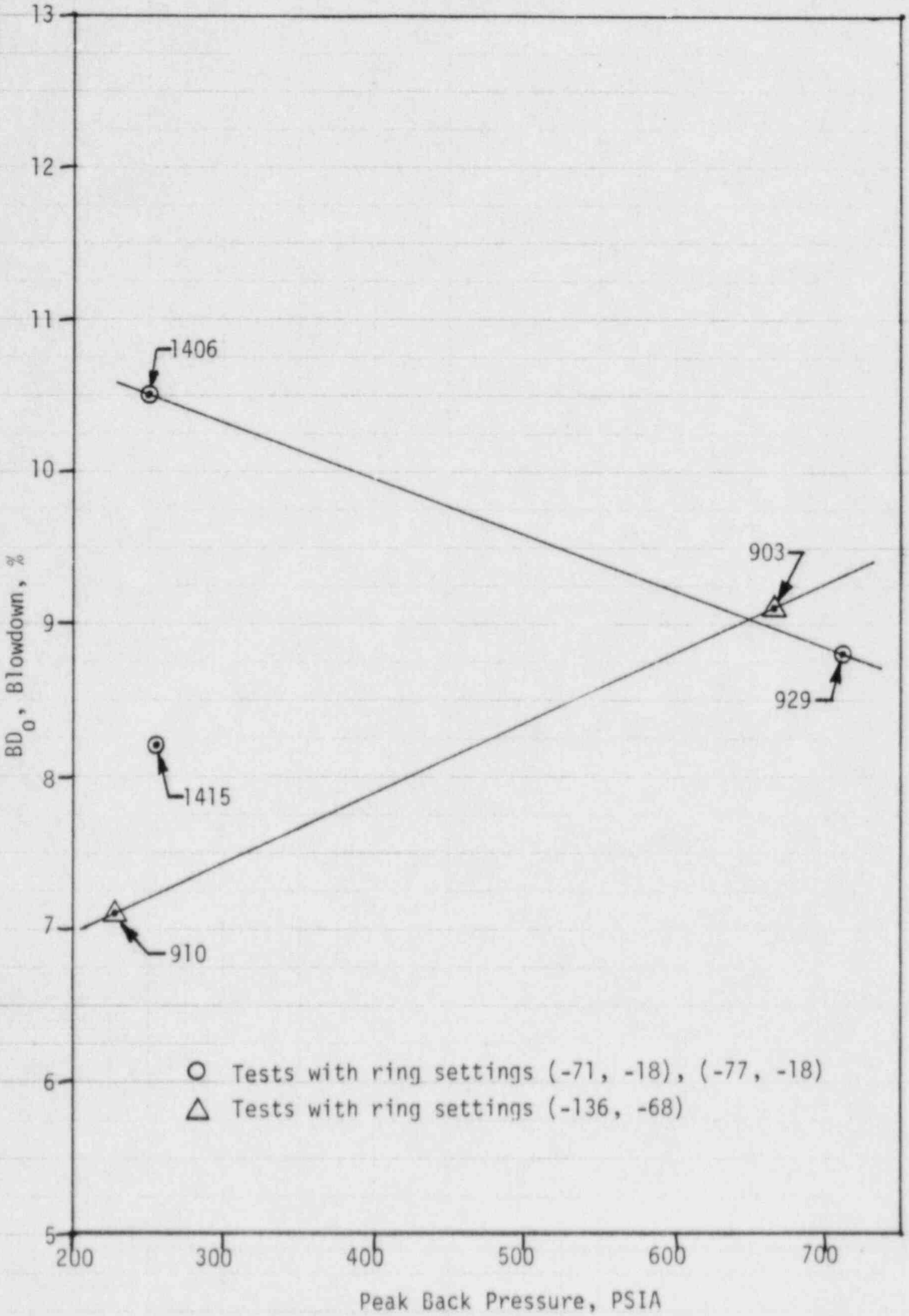


Figure B4-3 - Crosby HB-BP-86 6M6 Safety Valve
Blowdown vs. Peak Back Pressure



PART C - ARKANSAS NUCLEAR ONE UNIT 2 PRESSURIZER SAFETY VALVE OPERABILITY - PLANT-SPECIFIC EVALUATION

PART C - ARKANSAS NUCLEAR ONE - UNIT 2 PRESSURIZER SAFETY VALVE OPERABILITY - PLANT-SPECIFIC EVALUATION

1.0 GENERIC AND PLANT-SPECIFIC INFORMATION

1.1 INTRODUCTION

The plant-specific evaluation of the Arkansas Nuclear One Unit 2 safety valve operability is presented in this portion of the report. The evaluation is based on comparison of the in-plant installations and fluid conditions with the test data presented in Part B. Specifically, comparisons include valve model and installation, inlet fluid conditions, inlet transient pressure drop at valve opening, valve stem lift, back pressure, and valve discharge flange bending moment.

Tests which envelope the Arkansas Nuclear One Unit 2 conditions are considered to be directly applicable. The valve adjusting ring settings used in these tests are thus designated as "qualified" ring settings for the plant safety valves, provided the blowdown measured for the particular ring setting is within acceptable limits[1], and stable safety valve performance was demonstrated.

1.2 INLET FLUID CONDITIONS

The EPRI test program based the tested valve inlet fluid conditions on FSAR/Reload Analyses of pressurization transients which result in safety valve actuation. The transients and associated fluid conditions are summarized in Reference 6.2. It should be noted that the peak pressurizer pressure and pressurization rates derived from the analyses are conservatively high, since the analyses do not credit non-safety grade systems such as pressurizer spray to mitigate the transients. Extended high pressure injection transients are not applicable for Arkansas Nuclear One Unit 2 since the HPSI pump shutoff head is below

[1] See Subsection 1.5, Part C, for further clarification.

the safety valve setpoints, as well as below normal operating pressure. Hence, the HPSI pumps are incapable of challenging the safety valves.

The Arkansas Nuclear One Unit 2 safety valve inlet fluid conditions were based on Cycle 2 Reload Analyses. The calculated highest peak pressurizer pressure of 2705 psia occurs for the Feedline Break event. The pressurization rates for the Arkansas Nuclear One Unit 2 events which actuate the safety valves range from 87.5 to 106 psi/sec; the highest rate is associated with the Feedline Break event. In all cases, the valve inlet fluid is limited to saturated steam.

Only steam flow through the safety valves needs to be considered for the following reasons. A review of Chapter 15 of the FSAR indicated that the feedwater line break (FWLB) accident has the greatest potential for driving the pressurizer water level to the safety valve inlet. The FWLB scenario includes the loss of offsite electrical power which causes a coastdown of all four reactor coolant pumps. As a result, the only remaining active mechanism credited for mitigation of the pressurizer level increase is the opening of the main steam safety valves. Failure of these valves to open is not considered credible. Therefore, other than the loss of offsite electrical power there are no credible single failures which could further increase the pressurizer level. Even with this limiting accident scenario and the very conservative analytical assumptions discussed in Appendix A, the fluid conditions at the valve remain as steam. The loads on the safety valves resulting from this limiting transient are considered in Part C, Section 1.7.

1.3 INLET TRANSIENT PRESSURE DROP

As previously noted (Part B, Section 3.5), the inlet transient pressure drop due to the acoustic expansion wave developed upon valve actuation is an important parameter characterizing safety valve opening stability. The following comparison indicates that valves having as-tested ring settings would operate with a greater margin for opening stability in the plant installation than in the EPRI test installation.

This is justified since the inlet piping acoustic pressure response at the valve inlet for the in-plant piping is less severe than that measured in the test.

The following pressure drops are calculated based on the procedure and data presented in Part B, Section 3.5.

1.3.1 Tested Piping Configuration Acoustic Pressure Drop

For the purpose of calculating the acoustic wave amplitude, the inlet piping diameter is conservatively assumed to equal the smallest restricting pipe diameter (D_{min} = 4.897 in, see Figure B4-1). The tested inlet piping length is 188.5 inches. The situation which applies to the tested configuration is:

$$(T_{op} = 0.010 \text{ sec}) < (2L/c = 0.022 \text{ sec})$$

Therefore, the acoustic wave pressure drop, based on the tested configuration inlet piping diameter of 4.897 inches, is given by:

$$\Delta P_{AW} = \frac{cM}{g_c A} = 299 \text{ psi}$$

1.3.2 Plant Piping Configuration Acoustic Pressure Drop

The situation which applies to the Arkansas Nuclear One Unit 2 inlet piping configuration (L - 21.1 inches, see Figure C2-1) is:

$$(T_{op} = 0.010 \text{ sec}) > (2L/c = 0.0025 \text{ sec})$$

The calculated acoustic wave pressure drop for the Arkansas Nuclear One Unit 2 safety valve inlet piping configuration is given by:

$$\Delta P_{AW} = \frac{2LM}{g_c A \, T_{op}}$$

The pressure drop is calculated using the inputs presented in Part B, Section 3.5 and the inlet piping diameter of 5-3/16 inches. The acoustic pressure drop equals:

$$\Delta P_{AW} = 67 \text{ psi}$$

1.3.3 Conclusion

It is concluded that since the calculated acoustic pressure drop for the tested configuration, 299 psi, is greater than the calculated pressure drop for the plant configuration, 67 psi, the tested configuration bounds the plant piping configuration. Stable valve performance during testing will assure stable operation in the plant.

1.4 SAFETY VALVE FLOW MODEL

The analytical model used to depict safety valve discharge in the Arkansas Nuclear One Unit 2 Chapter 15 safety analyses is shown in Figure C1-1.

Based on the analysis of the test results, the operating characteristics for the Crosby HB-BP-86 6M6 valve were developed (see Figure B4-5, Part B). The characteristic curves corresponding to 5, 10, and 15 - percent blowdown are representative of the Arkansas Nuclear One Unit 2 safety valves, adjusted to the recommended ring setting identified in the previous subsection. Figure C1-2 shows the 5, 10, and 15% - blowdown characteristic curves and the flow model curve used in the Chapter 15 safety analyses superimposed for comparative purposes. The curves demonstrate the capability of the safety valve to relieve overpressure. However, the safety analyses assume that the valve pops open with a 1% uncertainty of safety valve opening pressure. The comparison, therefore, illustrates the conservatism in the safety analyses assumption since the tests demonstrate that the safety valves open to the maximum flow area at the nominal set pressure. Thus, the peak pressurizer pressures determined in the safety analyses are not adversely impacted by the valve characteristics observed in the EPRI tests.

The Crosby HB-BP-86 6M6 valve operating characteristics shown in Figure C1-2 were used in the analysis to demonstrate the acceptability of the increased blowdown for the Arkansas Nuclear One Unit 2. Recommended ring settings will be based on the results of this analysis.

1.5 BACK PRESSURE

The ranges of the Arkansas Nuclear One Unit 2 safety valve built up back pressures of 553 to 569 psia, were determined on a plant-specific basis and provided by the utility. These built up back pressures refer the cases with both safety valves discharging and correspond to safety valves PSV-4634 and PSV-4633, respectively.

Figure C1-1
ARKANSAS NUCLEAR ONE UNIT 2
PRESSURIZER SAFETY VALVE FLOW MODEL
USED IN THE CHAPTER 15 SAFETY ANALYSES

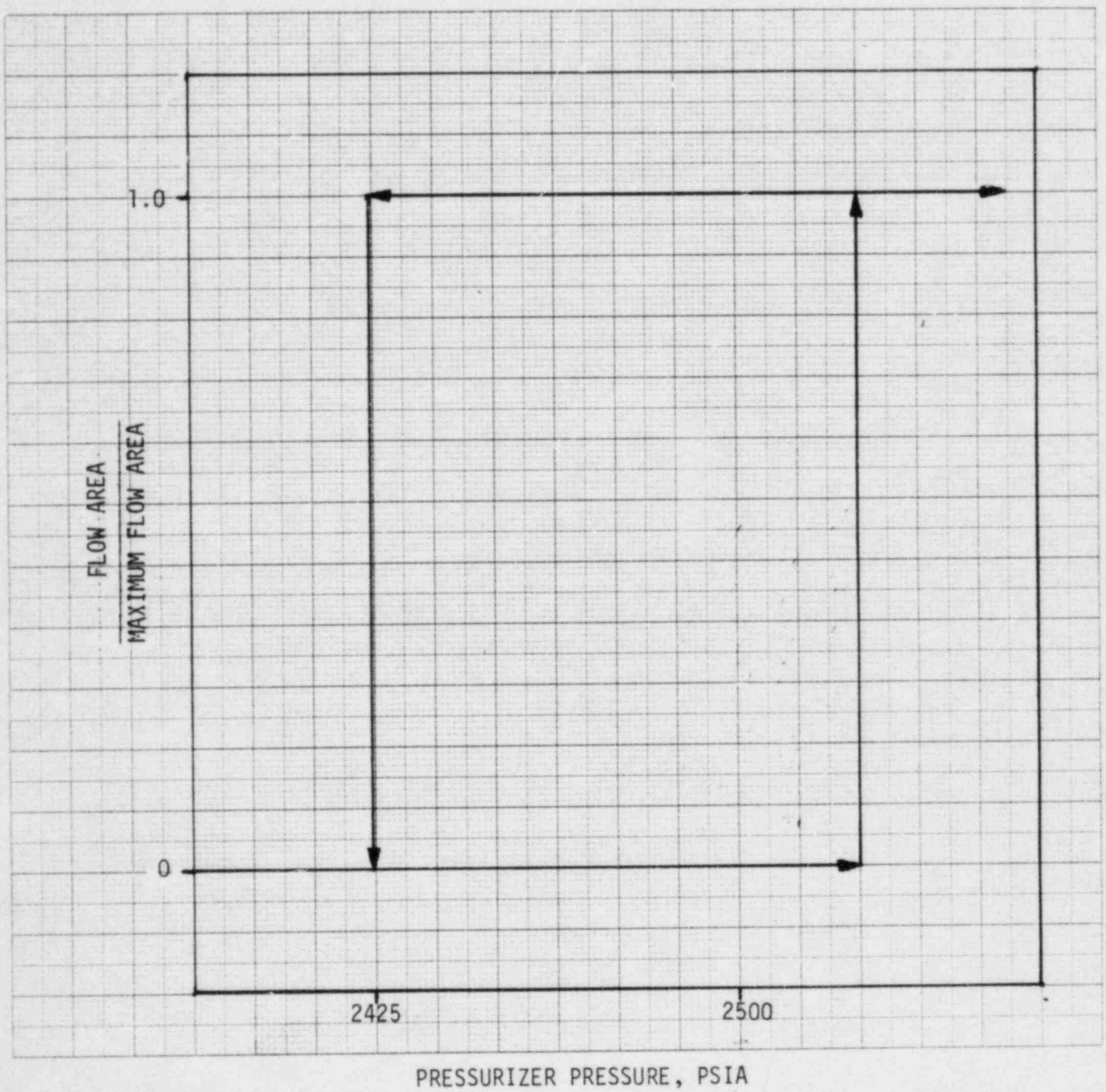
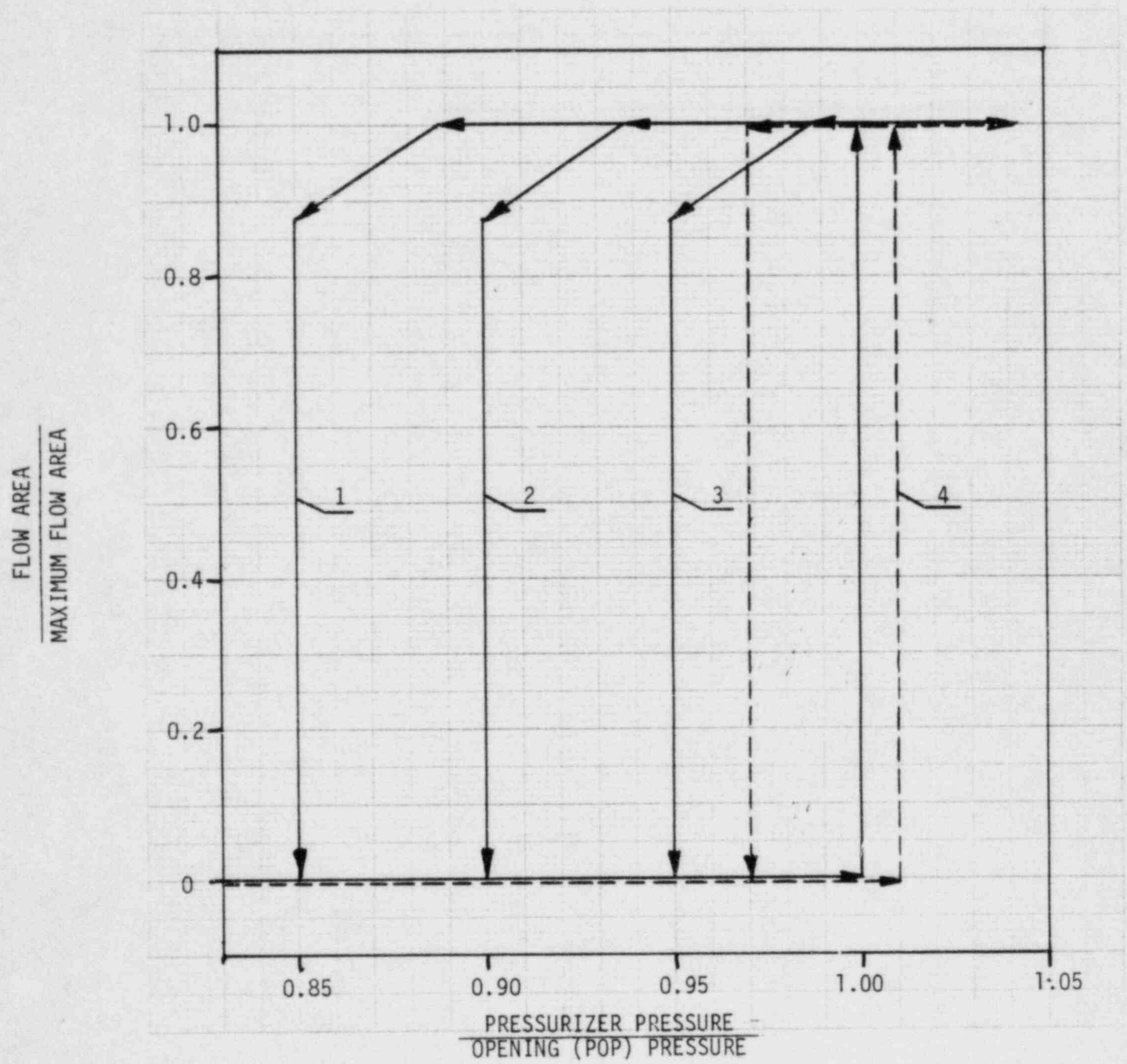


Figure C1-2

COMPARISON OF THE ARKANSAS NUCLEAR ONE UNIT 2
SAFETY VALVE FLOW MODEL USED IN SAFETY ANALYSES AND
CROSBY HB-BP-86 6M6 VALVE OPERATING CHARACTERISTICS OBSERVED
IN EPRI TESTS



Notes: 1 - Operating characteristic observed in tests (at 15% blowdown)
2 - Operating characteristic observed in tests (at 10% blowdown)
3 - Operating characteristic observed in tests (at 5% blowdown)
4 - Chapter 15 Safety Analyses assumptions

1.6 BLOWDOWN

The EPRI tests demonstrated that stable safety valve operation is generally associated with blowdown above 5 percent. Prior to 1975, the ASME Code, to which the safety valves were designed and built, required that blowdown not exceed 5 percent. However, beginning with the Summer 1975 Addenda to the 1974 ASME Code (paragraph NB-7614.2) blowdown in excess of 5 percent is permitted if appropriate justification is provided.

The concern with an extended blowdown of the plants' safety valves is that the pressurizer pressure might decrease sufficiently below the pressure corresponding to the pressurizer liquid saturation temperature. The reduction in pressure would then cause flashing and an excessive increase in the pressurizer level. If the two-phase level reaches the elevation of the safety valve nozzle, the valve could encounter either a two-phase mixture or solid water conditions at the inlet. Accordingly, it is desired to limit the level swell to below the pressurizer safety valve nozzle since the discharge piping and supports are not designed for two-phase or water relief, nor are the safety valves designed to operate with these fluid conditions[1].

Analyses which show that the extended blowdowns expected for the Arkansas Nuclear One Unit 2 safety valves will not result in the pressurizer two-phase level reaching the safety valve nozzles are described in Appendix A. Based on these analyses, it is concluded that following valve actuation, the steam fluid conditions at the Arkansas Nuclear One Unit 2 safety valves inlets will be maintained, despite the extended blowdown.

---

1 Transition to water conditions does not imply valve, piping, or support failures, but only that additional design impacts may need to be considered should transition to two-phase or water occur.

1.7 VALVE DISCHARGE FLANGE BENDING MOMENT

The effect of discharge piping loads on safety valve operability is determined by comparing the calculated bending moment on the valve discharge flange for the in-plant installation to the maximum measured moment for the applicable tests.

In the analysis of the structural adequacy of the Arkansas Nuclear One Unit 2 safety valve discharge piping, the calculated maximum bending moment on the valve discharge flanges is 103,889 in-lbs.

2.0 OPERABILITY EVALUATION

2.1 SAFETY VALVES AND INSTALLATION

The Arkansas Nuclear One Unit 2 Reactor Coolant System is provided with two Crosby Model HB-BP-86 6M6 pressurizer safety valves with a set pressure of 2485 psig. A general description of a Crosby safety valve is provided in Part B, Subsection 2.1. The Crosby HB-BP-86 6M6 test valve parameters are listed in Part B, Table B4-1. The Arkansas Nuclear One Unit 2 safety valve parameters are identical to the test valve with the exception of inlet flange rating which is a 2500 pound instead of a 1500 pound design for the test valve.

The Arkansas Nuclear One Unit 2 safety valves are connected directly to the pressurizer nozzles which are located at the top of the pressurizer. The longest of the plant safety valve inlet piping configurations is shown in Figure C2-1. The piping is 6" schedule 160 with a total length, from the inside of the pressurizer to the valve inlet flange mating surface, of 21.1 inches.

2.2 APPLICABILITY OF TESTS

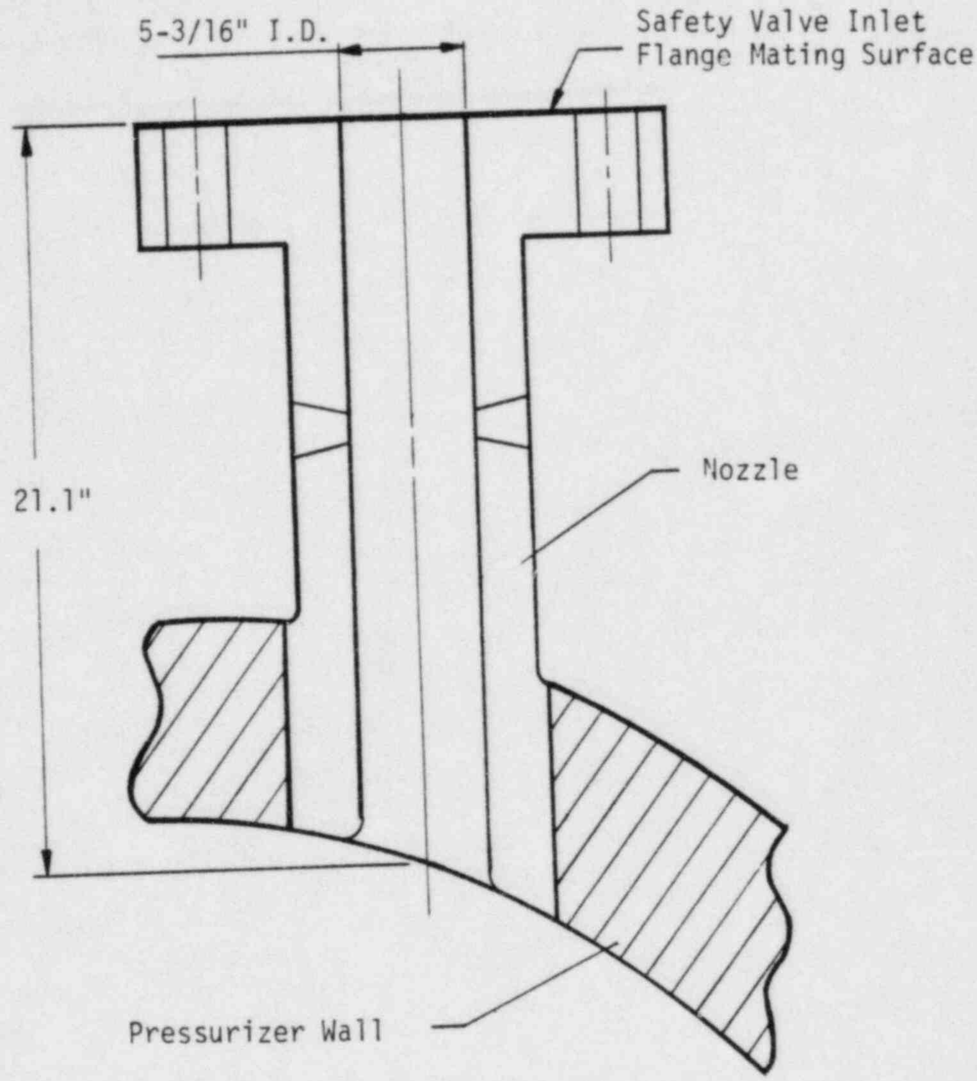
A total of thirteen steam and steam-to-water transition tests exhibiting stable valve operation were performed on the Crosby Model

FIGURE C2-1

ARKANSAS NUCLEAR ONE UNIT 2

PRESSURIZER SAFETY VALVE

INLET PIPING CONFIGURATION



HB-BP-86 6M6 safety valve (see Part B, Table B4-2). A total of three tests on steam conditions exhibited unstable valve operation. The applicability of these tests to the Arkansas Nuclear One Unit 2 safety valves is justified below.

In all of the tests but three, the test valve opened on water loop seal at the safety valve inlet. The remaining three tests were performed with a drained loop seal with the valve opening on steam. Since Arkansas Nuclear One Unit 2 has no loop seal, the valve opening action of these three tests where the valve opened on steam would be most representative of the Arkansas safety valves.

The range of peak pressures measured in Tank 1 during these tests (2389 to 2760 psia) enveloped the calculated Arkansas Nuclear One Unit 2 peak pressurizer pressure of 2705 psia. The tests were initiated with pressurization rates from 1.3 to 375 psi/sec that enveloped the Reload Analyses range of 87.5 to 106 psi/sec. In all sixteen tests, the valve stem reached full flow lift at opening.

Thus, the inlet fluid conditions for the above tests are considered to be representative of the plant conditions. However, since transition to water does not occur in the Arkansas Nuclear One Unit 2 plant, only the steam portion of Tests 914, 926 and 931 are applicable.

The range of builtup (peak) back pressures measured in the applicable tests (227 to 725 psia) enveloped the ranges of the calculated plant back pressures of 553 to 569 psia.

Plant-specific calculations show that the safety valve discharge flanges will be subjected to loadings which are significantly less than their tested loading capability. The calculated maximum bending moment on the valve discharge flange of 103,889 is less than the maximum bending moment of 298,750 in-lbs measured during the EPRI tests. The measured bending moment did not impair the operability of the valve.

2.3 EVALUATION

The analysis presented in Subsection 2.2 resulted in identifying the tests of the Crosby HB-BP-86 6M6 safety valve which are directly applicable to the plant safety valves. The applicable tests were selected from Test Series 900 and 1400 of the EPRI Safety and Relief Valve Test Program. The following evaluation of the operability of the Arkansas Nuclear One Unit 2 safety valves is based on these results.

2.3.1 Tests with (-136, -68) Ring Settings

Six steam tests were performed with (-136, -68) ring settings. Every test but one was performed with a filled loop seal. In each of the five tests performed with a filled loop seal at the valve inlet, the valve experienced flutter or chatter during loop seal discharge. Since Arkansas Nuclear One Unit 2 has no loop seal at its safety valve inlet, the valve opening on a drained loop seal as performed in Test 903 best represents Arkansas. In Test 903 the valve opened at its setpoint and immediately popped to its full open position. Typically there is a delay between the initial opening pressure and pop pressure while the loop seal is discharging.

The tests were performed at both high and low back pressures and high and low pressurization rates. The adjusting ring settings resulted in blowdowns which ranged from 7.1 to 11.2%. Although the valve exhibited stable performance on steam conditions during five of the six tests, the test valve chattered on closing in the last test with ring setting (-136, -68), Test 920.

Since Test 920 was a repeat of Test 917, during which the valve operated with stable behavior, it appears the test valve was on the edge of stability with the long inlet test configuration during closure for these settings. The Arkansas Nuclear One Unit 2 safety valves which have a valve inlet piping length much

shorter than the tested configuration (21.1 inches versus 188.5 inches) can be expected to perform similar to the stable valve characteristics experienced in Test 917. Justification that the tested inlet piping configuration envelopes the plant inlet piping is provided in Section 1.3 of Part C. Therefore, the ring settings of (-136, -68) are considered to be qualified for Arkansas Nuclear One Unit 2.

2.3.2 Tests with (-44, -66) Ring Settings

For Tests 913 and 914 the upper ring was inadvertently set in an unintended location. Test 913, a steam test with filled loop seal, demonstrated stable performance during discharge and closing. Test 914, a low flow transition test, exhibited stable performance on the first two actuations. However, on the final actuation on steam prior to steam-to-water transition the valve chattered.

Therefore due to the unstable valve performance on steam conditions and the limited amount of test data for (-44, -66) ring settings, these ring settings are not considered to be qualified for Arkansas Nuclear One Unit 2.

2.3.3 Tests with (-186, -68) Ring Settings

Two tests were performed with (-186, -68) ring settings. Test 923 was a high pressurization rate steam test with a filled loop seal. After loop seal discharge, the valve demonstrated stable operation during opening, discharge and closing. Test 926 was a l w flow transition test with a drained loop seal. The valve cycled twice on steam before transition to water occurred. The valve demonstrated stable operation during both steam actuations including the discharge and closing on water. Both Tests 923 and 926 were performed with high back pressures. Blowdown was measured at 12.9 and 5.1% during Tests 923 and 926, respectively.

Although the valve demonstrated stable performance during both tests with (-186, -68) ring settings, the ring settings are not considered to be qualified for Arkansas Nuclear One Unit 2. This is due to the magnitude of blowdown measured during Test 923. A 12.9% blowdown exceeds the calculated allowable blowdown of 12% determined in the blowdown analysis.

2.3.4 Tests with (-71, -18) and (-77, -18) Ring Settings

A total of six steam and steam-to-water transition tests were performed with these ring settings. Each test was performed with a filled loop seal except for one of the steam tests. Each of the steam tests was performed with high pressurization rates and both high and low back pressures. The low flow transition test was performed with high back pressure.

These adjusting ring settings produced blowdowns ranging from 4.7 to 10.5% with an average blowdown equal to 8.1%. After loop seal discharge, the test valve demonstrated stable valve performance during opening, discharge and closing on steam conditions for five of the six tests. Similar to those tests on the (-136, -68) ring setting, as discussed in Section 2.3.1, the valve chattered when closing on steam in the final test, Test 1419. Test 1419 also happened to be a repeat of the preceding test, Test 1415.

The same justification for acceptable valve performance can be applied to these ring settings that was applied to the (-136, -68) ring setting. Since Test 1415 demonstrated stable valve operation, the Arkansas valve can be expected to behave like Test 1415 due to the shorter plant valve inlet piping as compared to the long inlet test configuration.

Thus, the ring settings of (-71, -18) and (-77, -18) are considered to be qualified for Arkansas Nuclear One Unit 2.

2.4 CONCLUSION

The preceding sections determined three ring settings to be acceptable for the Crosby model HB-BP-86 6M6 safety valves installed in the Arkansas Nuclear One Unit 2 plant. They are (-136, -68), (-71, -18) and (-77, -18) ring settings. Although each of these ring settings is qualified for the Arkansas Nuclear One Unit 2 safety valves it may be desirable to select one of these settings based on valve performance.

Of these qualified ring settings, the (-71, -18) ring setting is recommended for use in Arkansas Nuclear One - Unit 2.

The (-71, -18) and (-77, -18) ring settings resulted in blowdowns less than that measured during testing of the (-136, -68) ring settings. Since a lower blowdown is desirable for the Arkansas Nuclear One - Unit 2 plant, the (-71, -18) and (-77, -18) ring settings are preferred over the (-136, -68) ring setting. Also, because during testing the (-77, -18) ring setting was intended to be the same as the (-71, -18) setting, and in order to select a single ring setting for the Arkansas Nuclear One - Unit 2 plant, the (-71, -18) ring setting is recommended.

The (-71, -18) ring setting is the ring setting used in Arkansas Nuclear One - Unit 2.

APPENDIX A
JUSTIFICATION FOR INCREASED ARKANSAS NUCLEAR ONE - UNIT 2 SAFETY VALVE BLOWDOWN

APPENDIX A

JUSTIFICATION FOR INCREASED ARKANSAS NUCLEAR ONE - UNIT 2 SAFETY VALVE BLOWDOWN

1.0 PURPOSE

The purpose of this appendix is to provide the justification for the extended blowdown of the Arkansas Nuclear One - Unit 2 safety valves[1]. The safety valve ring settings[2] recommended by Combustion Engineering are expected to result in blowdown in excess of the 4% required by the valve specification. Beginning with the Summer 1975 Addenda to the 1974 ASME Code, paragraph NB-7614-2, blowdowns in excess of 5% were permitted if appropriate justification was provided.

2.0 SCOPE

The scope of this justification is limited to the pressurizer safety valves supplied to Arkansas Nuclear One - Unit 2.

3.0 ANALYSIS

3.1 Method

This analysis demonstrates that for the plant transient producing the highest liquid level in the pressurizer and considering level swell due to the flashing resulting from a 12% blowdown, the transient does not result in the pressurizer two-phase level reaching the safety valve nozzle elevation or a loss of hot leg subcooling.

---

[1] Crosby model HB-BP-86 6M6.

[1] Recommended Valve Ring Settings:

Upper Ring Position, 71 notches below the disc ring.

Lower Ring Position, 18 notches below the disc ring.

The potentially limiting Chapter 15 transients of the Arkansas Nuclear One Unit 2 FSAR with regard to pressurizer liquid swell and loss of hot leg subcooling during safety valve blowdown are the Feedwater Line Break (FWLB) and the Loss of Load (LOL). The most recent analysis of these events which were done for the Cycle 3 reload were the basis of the pressurizer safety valve increased blowdown evaluation. The FWLB transient was determined to be limiting in causing a larger insurge into the pressurizer. The FSAR Feedwater Line Break with Loss of Offsite Power event was reanalyzed using initial conditions which would specifically maximize the pressurizer level response. The volume increase due to level swell (resulting from flashing of saturated pressurizer liquid) as a function of the blowdown pressure was determined. This level was compared to the elevation of the safety valve nozzles to determine whether two-phase liquid would reach the safety valve inlet.

3.2 Assumptions

In the reanalysis of the Feedwater Line Break with Loss of Offsite Power event, the same conservative licensing assumptions used in the Arkansas Nuclear One - Unit 2 Cycle 5 Ground Rules were applied, with the following changes in order to maximize the pressurizer two-phase level:

(a) Initial pressurizer liquid volume was increased from 700 ft^3 to 910 ft^3, the technical specification LCO, to maximize the initial pressurizer liquid inventory.

(b) The pressurizer safety valve operating characteristics were modeled based on the data obtained from the EPRI Safety and Relief Valve Test Program for the Crosby HP-BP-86 6M6 valve.

In the calculation of the pressurizer level swell due to steam bubble formation the following assumptions were made:

(c) Any bubbles formed in the pressurizer liquid during flashing remain entrained in the liquid.

(d) The subcooled reactor coolant insurge into the pressurizer does not mix with the saturated water initially present.

4.0 DISCUSSION OF RESULTS

The results of the Feedwater Line Break with Loss of Offsite Power Analysis indicate that a blowdown of 12% will not result in the liquid level reaching the elevation of the safety valve nozzles. Since the blowdown with two safety valves discharging simultaneously is expected to be 8.1%, the conservative analysis indicates that liquid would not reach the valves under these conditions.

Considering the very conservative assumptions made with respect to mixing in the pressurizer and the disengagement of steam bubbles from within the liquid, as well as the numerous conservatisms inherent in the basic FWLB methodology, the maximum expected pressurizer liquid level should be less than that calculated. Also, the hot leg will remain subcooled throughout safety valve blowdown during the Feedwater Line Break event.

5.0 CONCLUSIONS

The increased blowdown resulting from the safety valve ring settings specified herein will ensure steam conditions at the valve when discharging. The increased blowdown will not result in the introduction of liquid water into the valves or a loss of hot leg subcooling during the design basis events considered in the plant design.

PART III

SAFETY AND RELIEF VALVE PIPING SYSTEM

A. Introduction

Attached is a report prepared by Nutech Engineers of Atlanta, Georgia. This report evaluates Unit I and Unit II safety and relief valve discharge piping and responds directly to questions asked in the request for additional information.

ARKANSAS NUCLEAR ONE - UNIT 1
PRESSURIZER SAFETY AND RELIEF VALVE DISCHARGE PIPING EVALUATION

2. Information Pertaining to Thermal Hydraulic Analysis

a. Evidence that the analysis was performed on the fluid transient cases producing the maximum loading on the safety/relief valve piping system. Identify the fluid conditions assumed including pressure, temperature, pressurization rate, fluid range, and number of valves actuated.

The ANO-1 Pressurizer is equipped with one power-operated relief valve (PORV) and two safety valves. The discharge from the actuation of these three valves is routed to the quench tank through separate piping up to the common header immediately upstream of the quench tank.

The FSAR and reload amendments were reviewed to determine the safety/relief valve condition resulting from the operational transient events which were considered in the plant design basis. These events, along with the corresponding valve setpoint opening, fluid state, and the maximum pressure and pressurization rate in the Pressurizer are listed below:

Event	Assumed SV Opening Setpoint (psig)	Possible Fluid State	Maximum Pressurizer Pressure (psig)	Maximum Pressure Rate (psi/sec)
Rod bank withdrawal from 20% full power	2575	Steam	2539	55
Rod bank withdrawal at startup	2500	Steam	2515	95
Rod ejection at hot zero power	2575	Steam	2662	175
LOFW with high RCS pressure trip	2500	Steam	2519	81
FW line break	2545	Steam	2591	115

The SRV discharge analysis for steam blowdown through the safety valves was performed with assumed inlet pressure at 2575 psig initially, ramping at 175 psi/sec until it reached 2662 psig; after that, the pressure was held constant. This is the predicted condition for rod ejection at hot zero power, and is the most severe case among the events listed above. The assumed valve opening time was 15 msec. For steam blowdown through the PORV, the assumed inlet pressure was 2500 psig initially, ramping at 175 psi/sec until it reached 2575 psig; after that, the pressure was held constant. The assumed valve opening time was 60 msec.

Subcooled water blowdown may be possible for those events resulting in extended high pressure injection. Review of FSAR events with conservative assumptions found that steam and feedwater line breaks could yield bounding inlet conditions for the PORV and safety valves as shown below:

Limiting Events	Assumed PSV Opening Setpoints (psig)	Possible Fluid State on Opening	Maximum Pressurizer Pressure (psig)	Max/Min Pressurizer Liq. Temp (F)
Steam Line Break	2500	Steam(1)	2500	602/400
Feed Water Line Break	2500	Steam(1)	2500	640/602(2)

(1) Initial opening of valve will be on steam. Subsequent opening could be possible on subcooled water.

(2) Without thermal mixing of the surge line liquid with the 650°F liquid normally in the pressurizer, the pressurizer safety valves could open on 650°F water.

A conservatively low temperature of 400°F was used as the valve inlet condition in the RELAP5 calculation based on the results of scoping calculations that determined that a lower liquid temperature resulted in higher pipe forces.

The thermal hydraulic analyses were performed separately for the three discharge lines. The effects of simultaneous (or nearly simultaneous) actuation of the valves were considered in the piping analysis as discussed in the responses to Question 3.

2. Information Pertaining To Thermal Hydraulic Analysis (continued)

b. The RELAP5/MOD1 computer code was used to perform the thermal-hydraulic analysis. Identify the program that was used to generate the fluid force histories and provide evidence that this program has been verified for similar fluid transient problems. Describe the method used to calculate the fluid forces.

The thermal-hydraulic calculations were performed with RELAP5-FORCE available on the UCCEL Corporation Cyber computer system. RELAP5-FORCE is a modified version of RELAP5/MOD1 Cycle 14 with the additional capability to compute hydraulic force on each pipe segment. Benchmark calculations have shown that the RELAP5-FORCE program preserves the results from RELAP5. Furthermore, the validity of RELAP5 FORCE calculated pipe segment forces was demonstrated through simulations of the EPRI-CE SRV test, the Edwards' blowdown experiments and the Hanson's blowdown experiments. A complete verification document of RELAP5-FORCE is being prepared by the UCCEL Corporation.

The pipe segment forces are calculated by the RELAP5FORCE with the following formula:

$$F = (P + \rho V|V|)_1 A_1 - (P + \rho V|V|)_2 A_2 + \frac{\partial}{\partial t} \int \rho V A dx$$

When implemented on the two-phase formulation, the force equation actually adopted is:

$$\begin{aligned} F = [&P + \alpha_\ell \rho_\ell V_\ell |V_\ell| + \alpha_v \rho_v V_v |V_v|)_1 \\ &- (P + \alpha_\ell \rho_\ell V_\ell |V_\ell| + \alpha_v \rho_v V_v |V_v|)_2]A \\ &+ L_{cv} \frac{d}{dt} (m_\ell + m_v) \end{aligned}$$

where:

F = Force on piping

P = Pressure

A = Pipe flow area

V = Fluid velocity

L_{cv} =Control volume length

m = Control volume flow rate

α = Void fraction

ρ = Density

and the subscripts are:

1 = Pipe outlet junction

2 = Pipe inlet junction indices

ℓ = Liquid phase

v = Vapor phase

2. Information Pertaining to Thermal Hydraulic Analysis (concluded)

c. An explanation of the method used to treat valve resistances in the analysis. Report the valve flow rates that correspond to the resistances used. Because the ASME Code requires derating of the safety valves to 90% of actual flow capacity, the safety valve analysis should be based on a flow rate of at least 111% of the flow rating of the valve, unless another flow rate can be justified. Provide information explaining how derating of the safety valves was handled and describe methods used to establish flow rates for the safety valves and PORVs in the analysis.

The ANO-1 Pressurizer is equipped with two Dresser 31759A safety valves, each with a bore diameter of 2.062 in and a bore area of 3.341 in^2. The Pressurizer is also equipped with a Dresser 31533VX-30 PORV, with a bore diameter of 1.094 in. The rated flow of each type of valve was calculated in accordance with the ASME Code as follows:

$$W_R = (0.9)\ K_D\ (51.5)\ A\ (1.03P + 14.7)$$

where:

W_R = Rated Valve Flow, lb_m/hr

K_D = Coefficient of discharge

P = Set pressure, psig

A = Bore area, in^2

The 0.9 factor in the ASME equation represents the 10% derating of safety valve flow rate. With a K_D of 0.975, the calculated rated flow for the PORV is 30.54 lb_m/sec at 2500 psig. The rated flow for each safety valve is 108.61 lb_m/sec. Valve flow capacities of 115% of the rated value were assumed in the thermal hydraulic analysis.

The valve flow rate is defined in the RELAP5 model by specifying an appropriate valve flow area. These areas were selected through a series of scoping calculations. It was determined that 0.005065 ft^2 and 0.02055 ft^2 areas would result in 35.126 lb_m/sec and 135.9 lb_m/sec of steady state flow at 2500 psig upstream pressure for the PORV and safety valves, respectively, which represents 115% of the calculated rated flow for each valve.

3. Information Pertaining to Structural Analysis

a. A detailed description of the methods and computer programs used to perform the analysis. Explain whether the program used has been properly verified for similar problems.

The ANO-1 Pressurizer SRV discharge piping was analyzed for the loads resulting from actuation of the PORV and safety valves using the PISTAR Computer Program. PISTAR is a proprietary piping analysis computer program owned and maintained by NUTECH, Inc. (NUTECH). PISTAR performs the analysis and evaluation of ASME Section III and ANSI B31.1 piping systems for static and dynamic loads. The analytical solvers used in PISTAR are based on the well known public domain program SAPIV, developed by the University of California at Berkeley.

PISTAR has been verified in accordance with a quality assurance program which conforms to the requirements of 10CFR50, Appendix B, ANSI N45.2.11 as amended by the USNRC Regulatory Guide 1.64, and Section III of the ASME Code. The verification was performed by comparing the important portions of the PISTAR solution for a series of benchmark problems to that obtained from manual calculations or from other computer programs such as ANSYS and EPIPE. Results of these comparisons showed good agreement between PISTAR and the manual calculations and other computer programs.

The analysis of the piping for the SRV discharge loads was performed using the direct integration time-history solution technique. This solution technique is commonly used in determining responses of structural systems to impulsive type loads such as SRV discharge loads. The validity of using this technique for this application has been previously demonstrated by comparison to actual test results. This solution technique in PISTAR was verified as described above.

The direct integration time-history analysis of the piping for the SRV discharge loads was performed using an integration time-step of 0.001 seconds. This integration time-step was used such that responses of the piping system up to 50 hertz would be accurately computed. Mass- and stiffness-proportional damping coefficients were specified such that one percent damping was obtained for the piping responses due to the PORV discharge loads and two percent damping was obtained for the piping responses due to the safety valve discharge loads. These damping values are consistent with those permitted by the USNRC Regulatory Guide 1.61, based on the pipe diameters and stress levels expected due to these loads. The analysis of the piping for the SRV discharge loads was performed for sufficient time duration to ensure that the maximum responses of the piping system were obtained. The discharge loads due to the PORV actuation and each of the two safety valve actuations were applied independently to each for the piping systems. These piping responses were then combined absolutely to obtain the total response of the piping system due to the discharge loads.

The piping supports were analyzed for the support reactions obtained from the piping analysis The supports were analyzed statically using manual techniques and using computer programs. The computer programs used in performing the analysis of the supports are described below:

1) GENSAP Computer Program - GENSAP performs the static analysis of elastic structures. The program is available through the Control Data Corporation (CDC) and has been verified in accordance with NUTECH's Quality Assurance Program.

2) BASEPLATE II and STARDYNE Computer Programs - BASEPLATE II is a preprocessor to the STARDYNE Computer Program and is used to generate the required input data for the STARDYNE subprograms STAR and SPRINGS. This combination of programs performs the non-linear flexible analysis of baseplates. BASEPLATE II and STARDYNE are available through CDC and are on the CDC nuclear safety-related list of computer programs.

3. Information Pertaining to Structural Analysis (Continued)

b. An identification of the load combinations performed in the analysis together with the allowable stress limits. Explain the mathematical methods used to perform the load combinations, and identify the governing codes and standards used to determine piping and support adequacy.

The load combinations, including the mathematical methods used to perform the load combinations, and the corresponding allowable stress limits are shown below:

- <u>Piping</u>

P-1: $P + DW + RV \leq 1.2S_h$

P-2: $P + DW + [DE^2 + RV^2]^{1/2} \leq 1.8S_h$

P-3: $P + DW + RV + SV \geq 1.8S_h$

P-4: $P + DW + [(RV+SV)^2 + ME^2]^{1/2} \leq 2.4S_h$

- <u>Piping Supports</u>(1)

S-1: $DW + TE + RV \leq 1.0$ times AISC allowables.

S-2: $DW + TE + [(RV+SV)^2 + ME^2] \leq 1.5$ times AISC allowables.

where:

DE = Design earthquake

(1) Standard piping component supports were evaluated using the load combinations shown and compared to the manufacturer's rated loads.

DW = Deadweight of the piping components and contained fluid (either saturated steam or subcooled water)

ME = Maximum earthquake

P = Internal pipe pressure

RV = Discharge loads resulting from actuation of the PORV for either the saturated steam condition or subcooled water condition.

SV = Discharge loads resulting from actuation of the safety valve for either the saturated steam condition or subcooled water condition.

TE = Thermal expansion of the piping and movement of the pipe anchors due to the expansion of the pressurizer and quench tank.

The governing codes and standards used to determine the adequacy of the piping and piping supports are listed below:

- o ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components," 1980 Edition with addenda up to and including the Winter 1980 Addenda.

- o American Institute for Steel Construction, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, dated November 1978.

3. Information Pertaining to Structural Analysis (concluded)

c. A final evaluation of stresses in the piping system. Provide a comparison between calculated piping stresses and support loads with allowables and identify problem areas. According to the current submittal, some overstresses were identified in the structural analysis and a more detailed review of the overstress problem is underway. Explain what modifications will be made to correct these overstresses and other problem areas and provide a schedule for implementation of modifications. Provide assurance that the valves will operate properly in the modified system.

Analysis of the as-built configuration of the Pressurizer SRV discharge piping showed stresses in the piping exceeded their allowables. To correct this overstress condition, several supports were added or relocated to reduce the stresses to within their allowables. The maximum stress for each load combination as compared to the allowables in the piping as modified are listed below:

Load Combination Number	Calculated Stress (psi)	Allowable Stress (psi)
P-1	11,043	17,352
P-2	11,856	26,028
P-3	18,543	26,028
P-4	18,674	34,704

Reaction loads obtained from the piping analysis of the modified piping configurations were combined as previously shown. For existing supports, the new loads were compared to the original design load for the support, and if the new load was smaller, the support was considered adequate for the new loads. For existing

supports in which the new loads exceeded the original design loads and new supports, the supports were analyzed and resulting loads or stresses were compared to their allowables. In some instances, the loads or stresses in the support exceeded their allowables and therefore required modification.

The modifications described above were implemented during the Refueling Outage 5 in early 1983. With the modifications installed, the loads and stresses in the piping and piping supports are within their allowables. Operability of the valves in the modified system were evaluated and the demonstration of the valve operability is discussed in response to Question 1.

ARKANSAS NUCLEAR ONE - UNIT 2

PRESSURIZER SAFETY AND RELIEF VALVE DISCHARGE PIPING EVALUATION

2. Information Pertaining to Thermal Hydraulic Analysis

a. Evidence that the analysis was performed on the fluid transient cases producing the maximum loading on the safety/relief valve piping system. Identify the fluid conditions assumed including pressure, temperature, pressurization rate, fluid range, and number of valves actuated.

The ANO-2 Pressurizer is equipped with two (2) safety valves. The discharge from these valves is routed to the quench tank through separate piping up to the common header immediately upstream of the quench tank.

The thermal hydraulic analysis performed assumed simultaneous actuation of two safety valves. The inlet condition was 100% quality steam with initial pressure of 2500 psia, ramping at 106.0 psi/sec, and with final pressure of 2705 psia. This condition represents the highest calculated Pressurizer pressure and ramping rate among the design basis transient events listed in the FSAR and reload license amendments. The transient events which result in safety valve actuations are listed below with the respective peak pressurizer pressures and ramping rates.

Event	Peak Pressurizer Pressure (psia)	Pressure Ramp Rate (psi/sec)	Fluid Condition
Loss of Load	2671	90.0	Steam
Feedline Break(1)	2705	106.0	Steam
CEA Withdrawal	2662	87.5	Steam
Loss of Condenser Vacuum(2)	2671	90.0	Steam

(1) With loss of AC on reactor trip.

(2) Loss of Condenser Vacuum is the same as Loss of Load.

2. Information Pertaining to Thermal Hydraulic Analysis (continued)

b. The RELAP5/MOD1 computer code was used to perform the thermal hydraulic analysis. Identify the program that was used to generate the fluid force histories and provide evidence that this program has been verified for similar fluid transient problems. Describe the method used to calculate the fluid forces.

The thermal hydraulic calculations were performed with RELAP5-FORCE available on the UCCEL Corporation Cyber computer system. RELAP5-FORCE is a modified version of RELAP5/MOD1 Cycle 14 with the additional capability to compute hydraulic force on each pipe segment. Benchmark calculations have shown that the RELAP5-FORCE program preserves the results from RELAP5. Furthermore, the validity of RELAP5-FORCE calculated pipe segment forces was demonstrated through simulations of EPRI-CE SRV test, Edwards' blowdown experiments and Hanson's blowdown experiments. A complete verification document of RELAP5FORCE is being prepared by the UCCEL Corporation.

The pipe segment forces are calculated by the RELAP5-FORCE with the following formulas:

$$F = (P + \rho V|V|)_1 A_1 - (P + \rho V|V|)_2 A_2 + \frac{\partial}{\partial t} \int \rho V A dx$$

When implemented on the two-phase formulation, the force equation actually adopted is:

$$\begin{aligned} F = [P &+ \alpha_\ell \rho_\ell V_\ell |V_\ell| + \alpha_v \rho_v V_v |V_v|)_1 \\ &- (P + \alpha_\ell \rho_\ell V_\ell |V_\ell| + \alpha_v \rho_v V_v |V_v|)_2]A \\ &+ L_{cv} \frac{d}{dt} (m_\ell + m_v) \end{aligned}$$

where:

F = Force on piping

P = Pressure

A = Pipe flow area

V = Fluid velocity

L_{cv} = Control volume length

m = Control volume flow rate

α = Void fraction

ρ = Density

and the subscripts are:

1 = Pipe outlet junction

2 = Pipe inlet junction indices

ℓ = Liquid phase

v = Vapor phase

2. Information Pertaining to Thermal Hydraulic Analysis (concluded)

c. An explanation of the method used to treat valve resistances in the analysis. Report the valve flow rates that correspond to the resistances used. Because the ASME Code requires derating of the safety valves to 90% of actual flow capacity, the safety valve analysis should be based on a flow rate of at least 111% of the flow rating of the valve, unless another flow rate can be justified. Provide information explaining how derating of the safety valves was handled and describe methods used to establish flow rates for the safety valves and PORVs in the analysis.

The ANO-2 pressurizer is equipped with two Crossby 6M6 safety valves, each with a bore diameter of 2.154 in. and a bore area of 3.644 in^2 The rated flow was calculated in accordance with the ASME Code (Reference 1). That is:

$$W_R = (0.9)\ K_D\ (51.5)\ A\ (1.03P + 14.7)$$

where:

W_R = Rated flow
K_D = Coefficient of discharge
P = Set pressure, psig
A = Bore area, in^2

The 0.9 factor in the ASME equation represents the 10% derating of safety valve flow rate. With K_D of 0.975, the calculated rated flow is 118.46 lb_m/sec at 2485.0 psig. A safety valve flow capacity of 115% of the rated value was assumed in the thermal hydraulic analysis.

The valve flow rate is defined in the RELAP5 model by specifying an appropriate valve flow area. This area was selected through a series of scoping calculations. It was determined that 0.02057 ft^2 area of the safety valve would result in 136.23 lb_m/sec of steady state flow at 2485 psig upstream pressure, which represents 115% of the calculated rated flow.

3. Information Pertaining To Structural Analysis

a. A detailed description of the methods and computer programs used to perform the analysis. Explain whether the program used has been properly verified for similar problems.

The ANO-2 Pressurizer SRV discharge piping was analyzed for the loads resulting from actuation of the safety valves using the TRMSAP Computer Program. TRMSAP is a proprietary piping analysis computer program owned and maintained by Teledyne Engineering Services, Inc. (TES). TRMSAP performs the analysis and evaluation of ASME Section III and ANSI B31.1 piping systems for static and dynamic loads. The analytical solvers used in TRMSAP are based on the well-known public domain program SAPIV, developed by the University of California at Berkeley.

TRMSAP was verified by comparing the important portions of the TRMSAP solution for a series of benchmark problems to that obtained from manual calculations or from other computer programs such as STARDYNE, EPIPE, ANSYS or ADLPIPE. Results of these comparisons showed good agreement between TRMSAP and the manual calculations and other computer programs.

The analysis of the piping for the SRV discharge loads was performed using the direct integration time-history solution technique. This solution technique is commonly used in determining responses of structural systems to impulsive type loads such as SRV discharge loads. The validity of using this technique for this application has been previously demonstrated by comparison to actual test results. This solution technique in TRMSAP was verified as described above.

The direct integration time-history analysis of the piping for the SRV discharge loads was performed using an integration time-step of 0.001 seconds. This integration time-step was used such that responses of the piping system up to 50 hertz would be accurately computed. Mass- and stiffness-proportional damping coefficients were specified such that one percent damping was obtained for the piping responses due to the safety valve discharge loads. These damping values are consistent with those permitted by the USNRC Regulatory Guide 1.61, based on the pipe diameters and stress levels expected due to these loads. The analysis of the piping for the SRV discharge loads was performed for sufficient time duration to ensure that the maximum responses of the piping system were obtained. The discharge loads due to each of the two safety valve actuations were applied simultaneously to the piping systems.

The piping supports were analyzed for the support reactions obtained from the piping analysis. The supports were analyzed statically using manual techniques and using computer programs. The computer programs used in performing the analysis of the supports are described below:

1) STRUDL Computer Program - STRUDL performs the static and dynamic analysis of elastic structures. The program is available through the McDonnell Douglas Automation Company (McAUTO) and is on McAUTO's nuclear safety-related list of computer programs.

2) BASEPLATE II and STARDYNE Computer Programs - BASEPLATE II is a preprocessor to the STARDYNE Computer Program and is used to generate the required input data for the STARDYNE subprograms STAR and SPRINGS. This combination of programs performs the non-linear flexible analysis of baseplates. BASEPLATE II and STARDYNE are available through CDC and are on the CDC nuclear safety-related list of computer programs.

3. Information Pertaining to Structural Analysis (Continued)

b. An identification of the load combinations performed in the analysis together with the allowable stress limits. Explain the mathematical methods used to perform the load combinations, and identify the governing codes and standards used to determine piping and support adequacy.

The load combination and the corresponding allowable stress limit used to evaluate the piping and supports is shown below:

- <u>Piping</u>

  $P + DW + SV \leq 1.2S_h$

- <u>Piping Supports</u>(1)

$DW + TE + SV \leq$ allowables provided in the AISC Specification.

where:

DW = Deadweight of the piping components and contained fluid

P = Internal pipe pressure

SV = Discharge loads resulting from actuation of the SV

TE = Thermal expansion of the piping and movement of the pipe anchors due to the expansion of the pressurizer and quench tank

(1) Standard piping component supports were evaluated using the load combinations shown and compared to the manufacturer's rated load.

The governing codes and standards used to determine the adequacy of the piping and piping supports are listed below:

- ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components," 1971 Edition.

- American Institute for Steel Construction, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, dated November 1978.

3. Information Pertaining To Structural Analysis (concluded)

c. A final evaluation of stresses in the piping system. Provide a comparison between calculated piping stresses and support loads with allowables and identify problem areas. According to the current submittal, some overstresses were identified in the structural analysis and a more detailed review of the overstress problem is underway. Explain what modifications will be made to correct these overstresses and other problem areas and provide a schedule for implementation of modifications. Provide assurance that the valves will operate properly in the modified system.

Analysis of the as-built configuration of the Pressurizer SRV discharge piping showed stresses in the piping to be less than their allowables. For the combination of internal pipe pressure, deadweight and safety valve discharge loads, the maximum stress in the piping is 16,359 psi with an allowable stress of 19,762 psi.

Reaction loads obtained from the piping analysis of the modified piping configurations were combined as previously shown. For existing supports, the new loads were compared to the original design loads for the support, and if the new loads were smaller, the support was considered adequate for the new loads. For existing supports in which the new loads exceeded the original design loads and for new supports, the supports were analyzed and resulting loads or stresses were compared to their allowables. In some instances, the loads or stresses in the support exceeded their allowables and therefore required modification.

The modifications described above were implemented during the Refueling Outage 3 in late 1983. With the modifications installed, the loads and stresses in the piping and piping supports are within their allowables. Operability of the valves in the modified system were evaluated and the demonstration of the valve operability is discussed in response to Question 1.