Westinghouse

Westinghouse Electric Company
Nuclear Power Plants
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

U.S. Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, D.C. 20555

Direct tel: 412-374-4728
Direct fax: 412-374-5005
e-mail: vijukrp@westinghouse.com

Your ref: Docket No. 52-006
Our ref: DCP/NRC1649

November 13, 2003

SUBJECT: Transmittal of Revised Responses to AP1000 DSER Open Items

This letter transmits Westinghouse revised responses to Open Items in the AP1000 Design Safety Evaluation Report (DSER). A list of the revised DSER Open Item responses transmitted with this letter is Attachment 1. The non-proprietary responses are transmitted as Attachment 2.

Please contact me at 412-374-4728 if you have any questions concerning this submittal.

Very truly yours,

R. P. Vijuk

R. P. Vijuk, Manager
Passive Plant Engineering
AP600 & AP1000 Projects

/Attachments

1. List of the AP1000 Design Certification Review, Draft Safety Evaluation Report Open Item Responses transmitted with letter DCP/NRC1649
2. Non-Proprietary AP1000 Design Certification Review, Draft Safety Evaluation Report Open Item Responses dated November 13, 2003

D063

November 13, 2003

Attachment 1

List of

Non-Proprietary Responses

Table 1 **"List of Westinghouse's Responses to DSER Open Items Transmitted in DCP/NRC1649"**	
3.6.3.4-2 Addendum 1, Revision 2	
5.3.3-1 Revision 2	
15.3-1 Revision 1	
17.3.2-2 Revision 1	
19.1.10.1-2 Revision 2	
21.5-1 Item Code Comparison	

DCP/NRC1649
Docket No. 52-006

November 13, 2003

Attachment 2

AP1000 Design Certification Review
Draft Safety Evaluation Report Open Item Non-Proprietary Responses

AP1000 DESIGN CERTIFICATION REVIEW

Draft Safety Evaluation Report Open Item Response

DSER Open Item Number: 3.6.3.4-2 Addendum 1 Revision 2

Original RAI Number(s): 251.004

Summary of Issue:

In RAI 251.005, the staff requested that the applicant provide values of crack morphology parameters, e.g., surface roughness, number of 45 degree and 90 degree turns, etc., that were used in generating the BACs for LBB. The NRC staff also asked for a comparative study, using the values of crack morphology parameters associated with transgranular stress corrosion cracking (TGSCC). This information and the study were requested to evaluate the BACs and to understand the sensitivity of the AP1000 LBB analyses to a crack morphology similar to PWSCC. In its response to RAI 251.005, the applicant provided the values of crack morphology parameters used in generating the BACs. However, since chlorides will be controlled at minimum levels in the AP1000 LBB candidate piping systems water environment and the hydrogen overpressure will keep the oxygen levels to near zero, the applicant discounted the possibility of TGSCC and considered the comparative study using the crack morphology parameters associated with TGSCC not necessary. The applicant's argument does not address the intent of RAI 251.005. The NRC staff performed an independent sensitivity study to assess the impact on the BACs due to a consideration of a TGSCC type of crack in the LBB analysis as a surrogate for PWSCC. The NRC staff's independent sensitivity study shows that the BACs might not be easily met by the most limiting piping. DCD Tier 2 Appendix 3B.3.3.4 does not rule out the possibility of a LBB candidate piping system not meeting the BAC limit either, as evidenced by the statement: "[i]f the point falls above the bounding analysis curve, the leak-before-break analysis criteria are not satisfied and the pipe layout or support configuration needs to be revised to meet the leak-before-break bounding analysis."

The information provided by the applicant has not been sufficient to address the staff position in SECY-93-087, discussed in DSER Section 3.6.3.1, on demonstrating that adequate margins on leakage, loads, and flaw sizes are available for AP1000 LBB candidate piping systems. In addition, the information provided is not sufficient to understand the degree to which PWSCC may affect LBB margins. Therefore, the staff is evaluating the appropriate analyses the applicant should perform to resolve these issues. The staff expects to issue a supplemental DSER on LBB. This is Open Item 3.6.3.4-2.

Westinghouse Response:

Westinghouse provided a response to this DSER Open Item in Westinghouse letter DCP/NRC1611 dated 8/13/2003. This addendum provides our assessment of the AP1000 piping systems designated as Leak-Before-Break (LBB), and provides the basis for the staff to complete the FSER on LBB.

Revision 2 of this response provides discussion and results of revised DVI-A piping analysis in Section 2.5 and Figures 10-15 of this addendum.

AP1000 Evaluation of Candidate LBB Piping Systems

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION

For AP1000 piping design, Westinghouse proposes to use a DAC/ITAAC approach similar to what was used for previous Design Certifications. Following the proposed DAC/ITAAC approach, the staff reviews and approves the methodology, design criteria, and analysis acceptance criteria that would be used to perform the detailed piping design. The methods, design criteria, and analysis acceptance criteria are referenced as Tier 2* information in the AP1000 Design Control Document (DCD). Westinghouse has also committed that a COL applicant would be required to complete the piping analyses for the piping systems designated as Leak-Before-Break (LBB) lines at the time of a COL application. These analyses would be completed as a condition of the COL. Similar to the other certified designs, the final piping design and analysis for the as-built piping are subject to ITAAC verification.

In the AP1000 Draft Safety Evaluation Report, the staff has indicated that additional information should be provided by Westinghouse to provide high confidence that the piping systems designated as LBB will be able to meet the LBB acceptance criteria at the time of a COL. To accomplish this, the staff requested Westinghouse to complete a piping stress analysis of one LBB candidate piping system and demonstrate that the piping stress analysis results are within the limits of the AP1000 LBB Bounding Analysis Curves included in the DCD. Westinghouse presented analysis results of the direct vessel injection line A (DVI-A) subsystem previously to the staff and these results are included in this report. Westinghouse plans to complete this analysis with the final AP1000 seismic response spectra included in the DCD and will provide updated results to the staff when they are available. The technical basis for the determination that the DVI-A subsystem represents a limiting analysis for AP1000 LBB is provided in this addendum.

The staff also indicated that Westinghouse should perform a qualitative assessment of other LBB candidate subsystems to demonstrate feasibility to qualify the lines for LBB, and provide reasonable assurance that the other LBB candidate subsystems will be within their respective BACs. This report describes the feasibility assessment for application of the LBB methodology to the high energy piping systems in the AP1000. The LBB feasibility assessment is based on comparisons between the AP1000 piping and the corresponding piping in the AP600 standard plant. Westinghouse completed the LBB analysis for the AP600 piping systems designated as LBB in support of AP600 design Certification. An assessment of the feasibility of successfully qualifying the AP1000 LBB lines that have not been analyzed is performed by applying correction factors to the piping analysis results for the AP600 plant. The AP600 lines are generally similar to the AP1000 plant lines. Factors are developed that account for the AP1000 seismic floor response spectra, the changes in the elevations of the pipe/equipment supports, and the changes in pipe diameter. Section 2 describes the assessment methodology. Section 3 discusses the results for each candidate LBB piping line. A brief summary is given in Section 5.

The majority of AP1000 piping systems that are identified as candidate LBB systems have been successfully licensed as LBB systems for operating plants. These include such systems as the reactor coolant loop, pressurizer surge line, residual heat removal systems, and safety injection systems. Additionally, the main steam lines are also identified as LBB candidate systems and these lines have also been qualified as LBB lines for both the AP600 and System 80+ designs.

The AP1000 employs passive safety systems that are critical in providing for emergency core cooling. Of these passive systems, the Direct Vessel Injection (DVI) and the 4th Stage Autromatic Depressurization System (ADS) are considered to be the most important portions of the passive safety system features in the mitigation of loss of coolant accidents. Therefore it is desirable that the layout of these piping systems not be significantly changed to accommodate qualification of the lines for LBB. Therefore, in order to provide further confidence of the feasibility of these lines to be qualified for LBB, additional evaluations have been performed. As previously stated, Westinghouse performed a complete stress analysis of the DVI-A with the final AP1000 seismic response spectra included in the DCD. The results of the DVI-A evaluations are provided in Section 2.5 and Table 3. For the evaluation of the 4th stage ADS piping, a bounding seismic increase factor is identified for the applicable seismic response spectra based on a comparison of seismic accelerations for each corresponding frequency. This bounding approach is more conservative than the methodology used for the other lines, and provides an additional level of confidence as to the feasibility of qualifying these critical piping systems for LBB.

2.0 ASSESSMENT METHODOLOGY

The candidate pipe lines for Leak-Before-Break for the AP1000 plant are listed in Table 1. The AP1000 pipe lines are generally similar to the corresponding AP600 lines. The lines are the same lines that were identified and analyzed for LBB for the AP600. A comparison of the AP1000 and AP600 LBB pipe lines was provided to the NRC in Westinghouse letter DCP/NRC1516, dated August 5th, 2002. In addition, the NRC staff visited Westinghouse and reviewed the detailed AP1000 piping arrangement including the three dimensional electronic model. Several of the AP1000 lines have larger pipe diameters. The normal operating temperatures and pressures are similar. The in-structure seismic response spectra for the AP1000 plant are different from the AP600 plant primarily because of the taller shield building and the taller walls for the steam generator and pressurizer subcompartments. The AP1000 spectra used are based on the most recent seismic analysis documented in Section 3.7 of Revision 6 to the DCD. The seismic analysis includes the impact of reduced shear wall stiffness as requested in DSER open item 3.7.2.3-1. The Bounding Analysis Curves (BACs) in the AP1000 Design Control Document are based on a reliable leak detection capability of 0.5 gallons per minute and ASME Code minimum values for material strength. DCD Subsection 5.2.5 provides a description of the leak detection monitors for AP1000. RCS leakage detection instrumentation is also addressed in Technical Specification 3.4.10. The Bounding Analysis Curve for the Main Steam line incorporates the material tensile and fracture toughness properties that were measured from material testing for the design of the AP600 plant. The following methodology addresses the differences between the AP1000 and the AP600 and uses the estimated stresses in the piping system in combination with the corresponding AP1000 LBB Bounding Analysis Curve to evaluate the feasibility of LBB for each pipe line.

TABLE 1
CANDIDATE LBB PIPE LINES

LINE	DESCRIPTION (AP1000)
1A	Primary Loop Hot Leg - 31"
1B	Primary Loop Cold Leg - 22"
2	Pressurizer Surgeline - 18"
3A	ADS Stage 2,3 - 14"
3B	ADS Stage 2,3 - 8"
3C	Pressurizer Safety - 6"
4A	ADS Stage 4 East - 18"
4B	ADS Stage 4 East - 14" (610F)
4C	ADS Stage 4 East - 14" (120F)
5A	ADS Stage 4 West - 18"
5B	ADS Stage 4 West - 14" (610F)
5C	ADS Stage 4 West - 14" (120F)
6A	Normal RHR Suction - 20"
6B	Normal RHR Suction - 12"
6C	Normal RHR Suction - 10"
7	Passive RHR Return - 14"
8A	DVI-A - 8" 316 (537F)
8B	DVI-A - 8" 316 (120F)
8C	DVI-A - 8" 304
8D	DVI-A - 8" schedule 40S
8E	DVI-A RNS - 6"
8F	DVI-A PXS - 8"
9A	DVI-B - 8" 316 (537F)
9B	DVI-B - 8" 316 (120F)
9C	DVI-B - 8" 304
9D	DVI-B - 8" schedule 40S
9E	DVI-B RNS - 6"
9F	DVI-B PXS - 8"
10	CMT-A (West) -8"
11	CMT-B (East) -8"
12	Main Steam - A (West) -38"
13	Main Steam - B (East) - 38"

2.1 SEISMIC PIPE STRESSES

The AP1000 pipe/equipment support elevations are used to select the AP1000 response spectra curves. These elevations are generally higher than the corresponding elevations for the AP600 plant. The AP600 pipe lines have been analyzed for seismic loading using the envelope response spectra methodology or the time history methodology (for the reactor coolant loop hot leg and cold leg lines). The AP600 seismic analysis models include the equipment and equipment supports. The seismic stresses for the AP1000 pipe lines are estimated by applying a seismic multiplication factor to the AP600 seismic stress. This multiplication factor is based on the horizontal in-structure seismic response spectra at the elevation of the highest pipe line support or equipment support for each particular pipe line model. The vertical response spectra are generally lower and have less of an effect on the seismic pipe stress. For each horizontal direction the peak of the AP1000 spectrum is divided by the peak of the AP600 spectrum. These ratios are shown on the seismic response spectrum curves in Figures 1 through 8. The largest of these two ratios from the two horizontal seismic response spectra is then used as the seismic multiplication factor. The factors are summarized in Table 2. The estimated seismic stress is then modified to account for the changes in pipe diameter as required. This is described in Section 2.2.

Table 2 SEISMIC MULTIPLICATION FACTORS				
LINE	DESCRIPTION (AP1000)	MAXIMUM SEISMIC ELEVATION (FT) AP600	 AP1000	AP1000 SEISMIC FACTOR
1A	Primary Loop Hot Leg - 31"	135	153	1.74
1B	Primary Loop Cold Leg - 22"	135	153	1.74
2	Pressurizer Surgeline - 18"	158	169	2.71
2	Pressurizer Surgeline - 18"	158	multi-point	1.36
3A	ADS Stage 2,3 - 14"	158	169	2.71
3B	ADS Stage 2,3 - 8"	158	169	2.71
3C	Pressurizer Safety - 6"	158	169	2.71
4A	ADS Stage 4 East - 18"	135	153	1.42
4B	ADS Stage 4 East - 14" (610F)	135	153	1.42
4C	ADS Stage 4 East - 14" (120F)	135	153	1.42
5A	ADS Stage 4 West - 18"	135	153	1.74
5B	ADS Stage 4 West - 14" (610F)	135	153	1.74
5C	ADS Stage 4 West - 14" (120F)	135	153	1.74
6A	Normal RHR Suction - 20"	135	153	1.42
6B	Normal RHR Suction - 12"	135	153	1.42
6C	Normal RHR Suction - 10"	135	153	1.42
7	Passive RHR Return - 14"	135	153	1.74
8A	DVI-A - 8" 316 (537F)	107	107	1.28 (1)
8B	DVI-A - 8" 316 (120F)	107	107	1.28 (1)
8C	DVI-A - 8" 304	107	107	1.28 (1)
8D	DVI-A - 8" schedule 40S	107	107	1.28 (1)
8E	RNS - 6"	107	107	1.28 (1)
8F	PXS - 8"	107	107	1.28 (1)
9A	DVI-B - 8" 316 (537F)	107	107	1.28
9B	DVI-B - 8" 316 (120F)	107	107	1.28
9C	DVI-B - 8" 304	107	107	1.28
9D	DVI-B - 8" schedule 40S	107	107	1.28
9E	RNS - 6"	107	107	1.28
9F	PXS - 8"	107	107	1.28
10	CMT-A (West) -8"	135	153	1.74
11	CMT-B (East) -8"	135	153	1.42
12	Main Steam - A (West) -38"	135	153	1.74
13	Main Steam - B (East) - 38"	135	153	1.74 (2)

Notes (1) Results are provided for DVI-A based piping stress analysis per Section 2.5.

(2) Assessment of the Main Steam – B (East) system is based on the results from the Main Steam – A (West) evaluation due to the similarity of the two systems.

2.2 PIPE LINE DIAMETER AFFECTS

Several of the AP1000 pipe lines have larger pipe diameters than the corresponding AP600 pipe line. The larger diameter results in a stiffer line for thermal expansion loads and a higher section modulus. For an applied thermal displacement, the moment in the pipe is proportional to moment of inertia and therefore proportional to the diameter cubed. Since the pipe section modulus is proportional to the diameter squared, the thermal stress in the pipe (stress equals moment/section modulus) is proportional to the pipe diameter. The diameter ratio approach is valid when the ratio of the pipe diameter to wall thickness remains the same while the diameter is increased. The thermal stress is caused by restraining the thermal growth of the pipe. The thermal stress is equal to the moment divided by the section modulus. The moment in the pipe is approximately proportional to the stiffness of the pipe which is represented by the moment of inertia. The piping system consists of straight section and elbows. The moment of inertia for an elbow can be taken as the moment of inertia of the straight pipe divided by the elbow flexibility factor. The affect on the thermal stresses in the pipe due to increasing the pipe diameter can be assessed by calculating the following ratios: (moment of inertia of pipe)/(section modulus of pipe), and (moment of inertia of bend/section modulus of bend). Based on these ratios, the following table shows that the thermal stress increases approximately in proportion to the pipe diameter.

DESCRIPTION	DIAM IN	LONG RADIUS ELBOW			3D BEND		
		FLEX FACTOR	I/S(PIPE) IN	I/S(BEND) IN	FLEX FACTOR	I/S(PIPE) IN	I/S(BEND) IN
AP600	10.75	2.11	5.38	2.55	1.05	5.38	5.10
AP1000	14.00	2.22	7.00	3.16	1.11	7.00	6.32
RATIO AP1000/AP600	1.30		1.30	1.24		1.30	1.24
AP600	12.75	2.15	6.38	2.96	1.08	6.38	5.93
AP1000	18.00	2.26	9.00	3.99	1.13	9.00	7.98
RATIO AP1000/AP600	1.41		1.41	1.35		1.41	1.35

For seismic and deadweight loads, the moment in the pipe is proportional to weight of the pipe plus its contents. Since the ratio of the pipe diameter to the wall thickness is essentially the same for AP1000 and AP600, the seismic and deadweight moments are proportional to the pipe diameter. The seismic or deadweight stress in the pipe (stress equals moment/section modulus) is therefore proportional to 1.0/diameter. Based on these ratios, the following table shows that the seismic stress decreases approximately in proportion to the pipe diameter.

DESCRIPTION	DIAM IN	WEIGHT PIPE+WATER LBS/FT	S(PIPE) IN^3	WEIGHT/S LBS/FT/IN^3	1.0/DIAM IN^(-1)
AP600	10.75	141	74.3	1.89	0.093
AP1000	14.00	231	160	1.45	0.071
RATIO AP1000/AP600				0.77	0.77
AP600	12.75	195	123	1.59	0.078
AP1000	18.00	380	336	1.13	0.056
RATIO AP1000/AP600				0.71	0.71

The total (maximum LBB) pipe stress is the sum of the stresses due to internal pressure, thermal expansion, deadweight, and seismic loads, where deadweight, thermal, and seismic loads are combined by absolute summation. The corresponding normal LBB stress is the sum of the stresses due to internal pressure, thermal expansion, and deadweight loads, where the deadweight and thermal loads are combined by algebraic summation. When the diameter increases the thermal stress should increase and the deadweight and seismic stresses should decrease. The deadweight stress from the AP600 pipe stress analysis is not readily available in the Stress Reports which provide the total normal condition stress (pressure plus deadweight plus thermal). The deadweight plus thermal stress for AP600 is readily calculated by subtracting out the pressure stress. The deadweight plus thermal stress for AP1000 can be obtained by applying a factor to the AP600 stress. In order to obtain a high estimated or maximum value for the total stress, the deadweight plus thermal stress is assumed to be proportional to the pipe diameter. This is not a large affect since the deadweight stresses are usually smaller than the thermal stress. Therefore, in order to obtain a conservative estimate of the total pipe stress the following relations are used:

- Pressures stress is same as AP600.
- Deadweight and thermal stresses are proportional to the pipe diameter.
- Seismic stresses are proportional to 1.0/diameter.
- Seismic stresses are increased by the ratio of the AP1000 to AP600 peak acceleration per Section 2.1.

2.3 MATERIAL STRENGTH AFFECTS

When the estimated maximum pipe stress is above the BAC (in the region of the material flow stress) in the AP1000 Design Control Document, consideration is given to higher material strength properties that are more representative of the actual values obtained from test data for specific material heats. This raises the magnitude of the BAC in the region of the Curve that corresponds to the material flow stress. Westinghouse reviewed the certified material test reports of 316 type stainless steel material of auxiliary lines in operating plants for samples of 169 Heats. The average (mean value) of the flow stress for these material tests was 23.7% higher than the ASME Code minimum flow stress. The summary of the certified material test report review as well as the calculated mean values are provided in Appendix A. Westinghouse therefore adjusted the BAC wherever necessary to reflect a 20% to 23.7% increase in the flow stress. The flow

stress or the $3S_m$ values, whichever is the minimum, has been used. LBB analysis is typically performed using actual tested material properties of the piping system. Using approximately average material properties for the AP1000 assessment is appropriate given the high probability of reducing the piping stresses in the actual piping analysis. At worst, it is possible to specify easily obtainable new minimum material properties for the AP1000 pipe, should they be required by the results of the detailed piping analyses.

The use of certified material properties test reports has been accepted by the NRC on plant specific applications of LBB.

2.4 LEAK RATE AFFECTS

When the estimated maximum pipe stress is above the BAC in the AP1000 Design Control Document consideration is given to increasing the leak detection capability. This raises the magnitude of the BAC in the region of the Curve that is below the material flow stress. Lower leak rate detection capability has been reviewed and accepted by the NRC on operating plant specific applications of LBB. It is not expected that lowering the leak detection rate will be required for the AP1000. It is relatively easy to move the piping analysis stress points to the right in the BAC assessment by increasing the normal stress in the piping system based on piping system support modifications.

2.5 AP1000-SPECIFIC PIPE STRESS ANALYSIS

Westinghouse has performed a detailed pipe stress analysis of one piping system. The Direct Vessel Injection – A system was selected to be analyzed because it represents a limiting piping analysis considering the following criteria:

Complexity of piping system - The DVI-A piping system is complex, and was particularly challenging to qualify for the AP600. TheAP600 design and analysis of the DVI-A subsystem was performed over several iterations that included perturbations in the piping layout, support configuration, and piping analysis. Figure 9 shows isometric views of both the AP600 and AP1000 DVI-A piping system.

Low Margin to BAC for AP600 - The AP600 analysis results for the DVI-A line exhibited low margin to the AP600 BAC limits. In addition, the limit for one particular line segment actually exceeded the BAC. (For that segment, engineering judgement was used to determine that modification of the final support configuration would result in reducing the stress limits to below the BAC for that line segment). Therefore it is expected that the DVI-A would be one of the most difficult piping systems to qualify for LBB for the AP1000.

Minimum line size qualified for LBB - The DVI-A piping subsystem contains the smallest size line segment qualified for leak before break. Typically smaller lines are the most challenging to qualify for LBB. The DVI-A contains 6-inch piping, which is the smallest pipe size designated as LBB for the AP1000.

Potential for subcompartment pressurzation impact - The DVI-A traverses several subcompartments in the AP1000 containment. These subcompartments are not designed for the break of a high energy line of the size included in the DVI-A piping system. Therefore, if the DVI-A piping system were not qualified for LBB, additional subcompartment pressurization analyses would be required to demonstrate that the subcompartments are adequate.

Based on these considerations, Westinghouse decided to perform the detailed piping analysis of the DVI-A piping system to demonstrate that this limiting piping subsystem could be qualified for LBB. **The analysis performed utilized the methodologies defined in AP1000 Piping Design Criteria Document (APP-GW-P1-001) and AP1000 Pipe Rupture Protection Design Criteria Document (APP-GW-N1-001). These criteria documents were developed consistent with AP1000 DCD Sections 3.7 and 3.9, and Appendix 3B respectively, and reviewed by the NRC Staff at the Westinghouse office in September 2002.**

These criteria documents define the mandatory analysis requirements for the AP1000 piping systems, including the applicable loading conditions and combinations, analysis methods, acceptance criteria based on the ASME B&PV Code, Section III, 1989 Edition up to and including the 1989 Addenda, and supplemental criteria as defined by the AP1000 DCD. Leak-Before-Break evaluation methods for candidate LBB piping systems, utilizing Bounding Analysis Curve methodologies, are also defined.

The evaluation of the DVI-A piping system includes a 3D seismic response spectrum analysis based on the in-structure response spectra as documented in Section 3.7 of the DCD. Analysis is performed utilizing enveloped response spectra considering 4% damping, SRSS combination of the 3 directions of shock (i.e. X, Y, and Z), and accounting for Closely Spaced Modes based on Regulatory Guide 1.92. The analysis is performed such that both the applicable ASME and supplemental stress limits, and corresponding LBB BACs are met.

Results from the ~~preliminary~~ analysies for the DVI-A system are summarized in Table 3 and provided in Figures 10 through 15. The calculated stresses for the various line segments included in the DVI-A piping subsystem are below the BACs. The following table summarizes the results.

Table 3
Summary of DVI-A ~~Preliminary~~ Piping Stress Analysis Results

Pipe Segment	Maximum Calculated Stress (ksi)	Bounding Analysis Curve Limit (ksi)	Report Figure
8-inch, 316SS, 537F	**26.5~~23.9~~**	41.6	Fig. 10
8-inch, 316SS, 120F	**25.8~~22.0~~**	**51.9~~44.0~~**	Fig. 11
8-inch, 304	**14.8~~13.8~~**	**16.2~~14.4~~**	Fig. 12
8-inch, Sch 40S	**14.6~~11.7~~**	22.7	Fig. 13
6-inch, RNS	**14.6~~14.5~~**	**26.1~~22.9~~**	Fig. 14
8-inch, PXS	**26.5~~22.3~~**	**45.4~~44.5~~**	Fig. 15

These ~~preliminary~~ analysis results demonstrate the feasibility that the DVI-A piping subsystem can be qualified for LBB at the time of a COL application. ~~The final analysis results for the DVI-A piping system will be made available to the NRC when they are completed.~~

3.0 ASSESSMENT RESULTS

This section provides the results of the AP1000 LBB assessment for each candidate line.

3.1 Primary Loop Hot Leg (31") – (Reference AP1000 DCD Figure 3B-2)

The Hot Leg pipe diameter is the same as AP600. The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support. The maximum stress is 29.5 ksi which is less than the BAC stress of 40.7 ksi. Figure 16 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.2 Primary Loop Cold Leg (22") – (Reference AP1000 DCD Figure 3B-3)

The Cold Leg pipe diameter is the same as AP600. The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support. The maximum stress is 42.6 ksi which is lower than the modified BAC stress of 49.9 ksi. Figure 17 shows the BAC and the estimated stresses for the AP1000 plant. Therefore, the feasibility of LBB for AP1000 is confirmed.

3.3 Pressurizer Surgeline (18") – (Reference AP1000 DCD Figure 3B-6)

The Surgeline pipe diameter is the same as AP600. The seismic multiplication factor is 1.36. This includes the affect of the higher elevation of the pressurizer center of gravity and the use of multiple input point seismic response spectra analysis. Applying the multiple input method in place of the envelope response spectra method reduces the SSE factor from 2.71 to 1.36. The damping value for the multiple input method is taken as 3% for the Surgeline. For the multiple input method an equivalent uniform acceleration is needed to apply to the AP600 SSE stresses. The equivalent uniform input is taken to be the peak spectral acceleration at the elevation of the center of gravity of the AP1000 Pressurizer Tank. This acceleration is higher than the AP600 peak spectral acceleration, which is at the top of the Pressurizer subcompartment walls. The maximum stress is 32.7 ksi which is less than the BAC stress of 40.3 ksi. Figure 18 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.4 ADS Stage 2 and 3 (14") – (Reference AP1000 DCD Figure 3B-10)

The Stage 2 and 3 pipe diameter is the same as AP600. The seismic multiplication factor is 2.71. This includes the affect of the higher elevation of the pressurizer upper lateral support. The maximum stress is 31.8 ksi which is less than the BAC stress of 40.3 ksi. Figure 19 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.5 ADS Stage 2 and 3 (8") – (Reference AP1000 DCD Figure 3B-16)

The Stage 2 and 3 pipe diameter is the same as AP600. The seismic multiplication factor is 2.71. This includes the affect of the higher elevation of the pressurizer upper lateral support. The maximum stress is approximately 48 ksi which is more than the BAC stress of 40 ksi. Using more realistic material strength the modified BAC stress limit can be increased to 48 ksi. Figure 20 shows the BAC and the estimated stresses for the AP1000 plant. Therefore, the feasibility of LBB for AP1000 is confirmed.

3.6 Pressurizer Safety (6") – (Reference AP1000 DCD Figure 3B-19)

The Pressurizer Safety pipe diameter is the same as AP600. The seismic multiplication factor is 2.71. This includes the affect of the higher elevation of the pressurizer upper lateral support. The maximum stress is 61.9 ksi which is higher than the BAC stress of 40.4 ksi. Figure 21 shows the BAC and the estimated stresses for the AP1000 plant. This stress is calculated based on the conservative methods previously described in Section 2. Utilizing detailed time-history seismic analysis methods as opposed to response spectra methods previously utilized for AP600, it is anticipated that the analytical results will be significantly lower than those obtained by the conservative ratios developed. In the event that the results from the detailed time-history seismic results still exceed the BAC limits, the affects of postulated high energy line pipe breaks in the two 6" Safety lines would need to be evaluated. These pipe breaks are above the top of the Pressurizer subcompartment walls, and do not effect the design for subcompartment pressurization. Therefore the breaks would not have any adverse impact on the structural design of the Containment Internal Structure. Pipe whip restraints can be installed on the ADS pressurizer platforms at the locations shown in Figure 22 to ensure that the adjacent components that are needed to mitigate the pipe break (i.e. ADS Stage 1, 2, and 3 valves and piping)are not compromised.

3.7 ADS Stage 4 East (18") – (Reference AP1000 DCD Figure 3B-7)

The ADS Stage 4 pipe diameter is larger than the AP600 (12"). The seismic multiplication factor is 1.42. This includes the affect of the higher elevation of the steam generator upper lateral support in the East Subcompartment. The maximum stress is 26.3 ksi before adjustment for pipe diameter and 30.9 ksi after adjustment. The adjusted stress is less than the BAC stress of 40.7 ksi. Figure 23 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.8 ADS Stage 4 West (18") – (Reference AP1000 DCD Figure 3B-7)

The ADS Stage 4 pipe diameter is larger than the AP600 (12"). The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support in the West subcompartment. The maximum stress is 20.4 ksi before adjustment for pipe diameter and 23.2 ksi after adjustment. The adjusted stress is less than the BAC stress of 40.7 ksi. Figure 23 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.9 ADS Stage 4 East (14"- 610F) - (Reference AP1000 DCD Figure 3B-8)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). The seismic multiplication factor is 1.42. This includes the affect of the higher elevation of the steam generator upper lateral support. The maximum stress is 31.4 ksi before adjustment for pipe diameter and 34.8 ksi after adjustment. The adjusted stress is less than the BAC stress of 40.7 ksi. Figure 24 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.10 ADS Stage 4 West (14"- 610F) – (Reference AP1000 DCD Figure 3B-8)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support. The maximum stress is 32.7 ksi before adjustment for pipe diameter and 27.0 ksi after adjustment. The adjusted stress is less than the corresponding BAC stress of 31.6 ksi. Figure 24 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.11 ADS Stage 4 East (14"- 120F) – (Reference AP1000 DCD Figure 3B-9)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). The seismic multiplication factor is 1.42. This includes the affect of the higher elevation of the steam generator upper lateral support. The maximum stress is 30.4 ksi before adjustment for pipe diameter and 32.9 ksi after adjustment. The adjusted stress is less than the BAC stress of 51.9 ksi. Figure 25 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.12 ADS Stage 4 West (14"- 120F) – (Reference AP1000 DCD Figure 3B-9)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support. The maximum stress is 26.7 ksi before adjustment for pipe diameter and 24.4 ksi after adjustment. The adjusted stress is less than the BAC stress of 51.9 ksi. Figure 25 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.13 Normal RHR Suction (20") – (Reference AP1000 DCD Figure 3B-5)

The Normal RHR Suction pipe diameter is the same as AP600. The seismic multiplication factor is 1.42. This includes the affect of the higher elevation of the steam generator upper lateral support in the East subcompartment. The maximum stress is 17.9 ksi which is less than the BAC stress of 40.7 ksi. Figure 26 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

3.14 Normal RHR Suction (12") – (Reference AP1000 DCD Figure 3B-20)

The Normal RHR Suction pipe diameter is the same as AP600. The seismic multiplication factor is 1.42. This includes the affect of the higher elevation of the steam generator upper lateral

support in the East subcompartment. The maximum stress is 30.0 ksi which is less than the BAC stress of 40.7 ksi. Figure 27 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.15 Normal RHR Suction (10") – (Reference AP1000 DCD Figure 3B-21)

The Normal RHR Suction pipe diameter is the same as AP600. The seismic multiplication factor is 1.42. This includes the affect of the higher elevation of the steam generator upper lateral support in the East subcompartment. The maximum stress is 38.9 ksi which is less than the BAC stress of 40.7 ksi. Figure 28 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.16 Passive RHR Return (14") – (Reference AP1000 DCD Figure 3B-11)

The Passive RHR Return pipe diameter is larger than the AP600 (10"). The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support in the West subcompartment. The maximum stress is 59.1 ksi before adjustment for pipe diameter and 51.4 ksi after adjustment. The adjusted stress is higher than the BAC stress of 41.6 ksi. Using more realistic material strength the modified BAC stress limit is 51.4 ksi. Figure 29 shows the BAC and the estimated stresses for the AP1000 plant. Therefore, the feasibility of LBB for AP1000 is confirmed.

3.17 Direct Vessel Injection (DVI) – B (8", (316SS, 537F)) – (Reference AP1000 DCD Figure 3B-14)

The DVI-B (8", 316SS, 537F) pipe diameter is the same as AP600. The seismic multiplication factor is 1.28. This includes the elevation of the reactor vessel support. The maximum stress is 30.3 ksi which is less than the BAC stress of 41.6 ksi. Figure 30 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.18 Direct Vessel Injection (DVI) – B (8", (316SS, 120F)) – (Reference AP1000 DCD Figure 3B-15)

The DVI-B (8", 316SS, 120F) pipe diameter is the same as AP600. The seismic multiplication factor is 1.28. This includes the elevation of the reactor vessel support. The maximum stress is 23.7 ksi which is less than the corresponding BAC stress of 48.6 ksi. Figure 31 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.19 Direct Vessel Injection (DVI) – B (8", (304)) – (Reference AP1000 DCD Figure 3B-17)

The DVI-B (8", 304) pipe diameter is the same as AP600. The seismic multiplication factor is 1.28. This includes the elevation of the reactor vessel support. The maximum stress is 8.7 ksi which is less than the corresponding BAC stress of 10.5 ksi. Figure 32 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.20 Direct Vessel Injection (DVI) – B (8", (Sch 40S)) – (Reference AP1000 DCD Figure 3B-13)

The DVI-B (8", Sch 40S) pipe diameter is the same as AP600. The seismic multiplication factor is 1.28. This includes the elevation of the reactor vessel support. The maximum stress is 16.2 ksi which is less than the corresponding BAC stress of 21.3 ksi. Figure 33 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.21 Direct Vessel Injection (DVI) – B (6", RNS) – (Reference Figure 3B-18)

The DVI-B (6", RNS) pipe diameter is the same as AP600. The seismic multiplication factor is 1.28. This includes the elevation of the reactor vessel support. The maximum stress is 17.2 ksi which is less than the corresponding BAC stress of 27.0 ksi. Figure 34 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.22 Direct Vessel Injection (DVI) – B (8", PXS) – (Reference AP1000 DCD Figure 3B-15)

The DVI-B (8", PXS) pipe diameter is larger than the AP600. The seismic multiplication factor is 1.28. This includes the elevation of the reactor vessel support. The maximum stress is 26.6 ksi before adjustment for pipe diameter and 23.8 ksi after adjustment. The adjusted stress is less than the corresponding BAC stress of 35.2 ksi. Figure 35 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.23 Core Makeup Tank Supply – West (8") – (Reference AP1000 DCD Figure 3B-14)

The Core Makeup Tank Supply–West pipe diameter is the same as AP600. The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support in the West subcompartment. The maximum stress is 43.1 ksi which is higher than the BAC stress of 41.6 Using more realistic material strength the modified BAC stress limit is 50.0 ksi. Figure 36 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.24 Core Makeup Tank Supply – East (8") – (Reference AP1000 DCD Figure 3B-14)

The Core Makeup Tank Supply–East pipe diameter is the same as AP600. The seismic multiplication factor is 1.42. This includes the affect of the higher elevation of the steam generator upper lateral support in the East subcompartment. The maximum stress is 41.0 ksi which is higher than the corresponding BAC stress limit. Using more realistic material strength and the lower leak detection capability of 0.25 gpm the modified BAC stress limit of 42.8 ksi. Figure 36 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed.

3.25 Main Steam – A – West (38") – (Reference AP1000 DCD Figure 3B-4)

The Main Steam – A-West pipe diameter is larger than the AP600. The seismic multiplication factor is 1.74. This includes the affect of the higher elevation of the steam generator upper lateral support in the West subcompartment. The maximum stress is 27.7 ksi before adjustment for pipe diameter and 24.5 ksi after adjustment. The adjusted stress is higher than the corresponding BAC stress limit of 21.0 ksi. Using a lower leak detection capability of 0.25 gpm, the modified BAC stress limit is 25.9 ksi. Figure 37 shows the BAC and the estimated stresses for the AP1000 plant. The feasibility of LBB for AP1000 is confirmed. An alternative approach is to modify the pipe support configuration to shift the frequency response of the piping system away from the peak response spectra accelerations, thus producing a lower maximum stress point below the original BAC stress limit. Additionally, if required, detailed time-history seismic analysis methods could be used as opposed to envelope response spectra methods to obtain further reduction in the corresponding seismic stresses.

3.26 Main Steam – B – East (38") – (Reference AP1000 DCD Figure 3B-4)

The Main Steam – B-East pipe is similar to the West pipe. Stress estimates were not specifically calculated for this line. By similarity, the feasibility of LBB for AP1000 is confirmed.

4.0 4th Stage Automatic Depressurization System Evaluation

The Automatic Depressurization System (ADS) consists of four actuation stages and provides for Emergency Core Cooling following postulated accident conditions. These four stages are independent of each other and open sequentially, stage 1 through stage 4. The 4th stage ADS connects directly to the Reactor Coolant Hot Leg and vents into the applicable Steam Generator Compartment. This system can not operate until reactor coolant pressure has been significantly reduced.

Due to the critical nature of this system, an additional assessment of the seismic loadings is performed to further demonstrate the feasibility of Leak-Before-Break for these lines. The applicable seismic response spectra are reviewed for the 4th stage ADS, East and West, and the maximum increase in response spectra acceleration identified based on individual frequency. This review results in the following seismic increase factors as shown in Figures 38 and 39:

Location	Frequency	Increase Factor
Elevation 135' - X direction	8 Hz	2.1
Elevation 153' - Z direction	10 Hz	2.0

This approach adds an additional level of conservatism to the methodology described in Section 2.1

Results of the 4th Stage ADS seismic assessment are summarized in the following sections.

4.1 ADS Stage 4 East (18") – (Reference AP1000 DCD Figure 3B-7)

The ADS Stage 4 pipe diameter is larger than the AP600 (12"). Per Figure 38, the seismic increase factor is 2.1 based on the seismic response spectra at approximately 8 Hz. The maximum stress is 33.0 ksi accounting for both the seismic increase factor and the increase in pipe diameter. The adjusted stress is less than the BAC stress of 40.7 ksi. Figure 40 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

4.2 ADS Stage 4 West (18") – (Reference AP1000 DCD Figure 3B-7)

The ADS Stage 4 pipe diameter is larger than the AP600 (12"). Per Figure 39, the seismic increase factor is 2.0 based on the seismic response spectra at approximately 10 Hz. The maximum stress is 23.7 ksi accounting for both the seismic increase factor and the increase in pipe diameter. The adjusted stress is less than the BAC stress of 40.7 ksi. Figure 40 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

4.3 ADS Stage 4 East (14"- 610F) - (Reference AP1000 DCD Figure 3B-8)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). Per Figure 38, the seismic increase factor is 2.1 based on the seismic response spectra at approximately 8 Hz. The maximum stress is 38.0 ksi accounting for both the seismic increase factor and the increase in pipe diameter. The adjusted stress is less than the BAC stress of 40.7 ksi. Figure 41 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

4.4 ADS Stage 4 West (14"- 610F) – (Reference AP1000 DCD Figure 3B-8)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). Per Figure 39, the seismic increase factor is 2.0 based on the seismic response spectra at approximately 10 Hz. The maximum stress is 30.0 ksi accounting for both the seismic increase factor and the increase in pipe diameter. The adjusted stress is less than the BAC stress of 31.6 ksi. Figure 41 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

4.5 ADS Stage 4 East (14"- 120F) – (Reference AP1000 DCD Figure 3B-9)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). Per Figure 38, the seismic increase factor is 2.1 based on the seismic response spectra at approximately 8 Hz. The maximum stress is 36.5 ksi accounting for both the seismic increase factor and the increase in pipe diameter. The adjusted stress is less than the BAC stress of 51.9 ksi. Figure 42 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

4.6 ADS Stage 4 West (14"- 120F) – (Reference AP1000 DCD Figure 3B-9)

The ADS Stage 4 pipe diameter is larger than the AP600 (10"). Per Figure 39, the seismic increase factor is 2.0 based on the seismic response spectra at approximately 10 Hz. The maximum stress is 26.4 ksi accounting for both the seismic increase factor and the increase in pipe diameter. The adjusted stress is less than the BAC stress of 51.9 ksi. Figure 41 shows the BAC and the estimated stresses for the AP1000 plant. Feasibility of LBB for AP1000 is confirmed.

5.0 SUMMARY

This report summarizes an assessment of applying Leak-Before-Break methodology to the candidate AP1000 plant pipe lines listed in Table 1. Feasibility is demonstrated for the LBB candidate piping systems with one possible exception of the Pressurizer Safety Valve inlet piping (6"). For these two lines, the high energy pipe breaks can be mitigated by the installation of protection devices (whip restraints) as shown at the locations in Figure 22 if required.

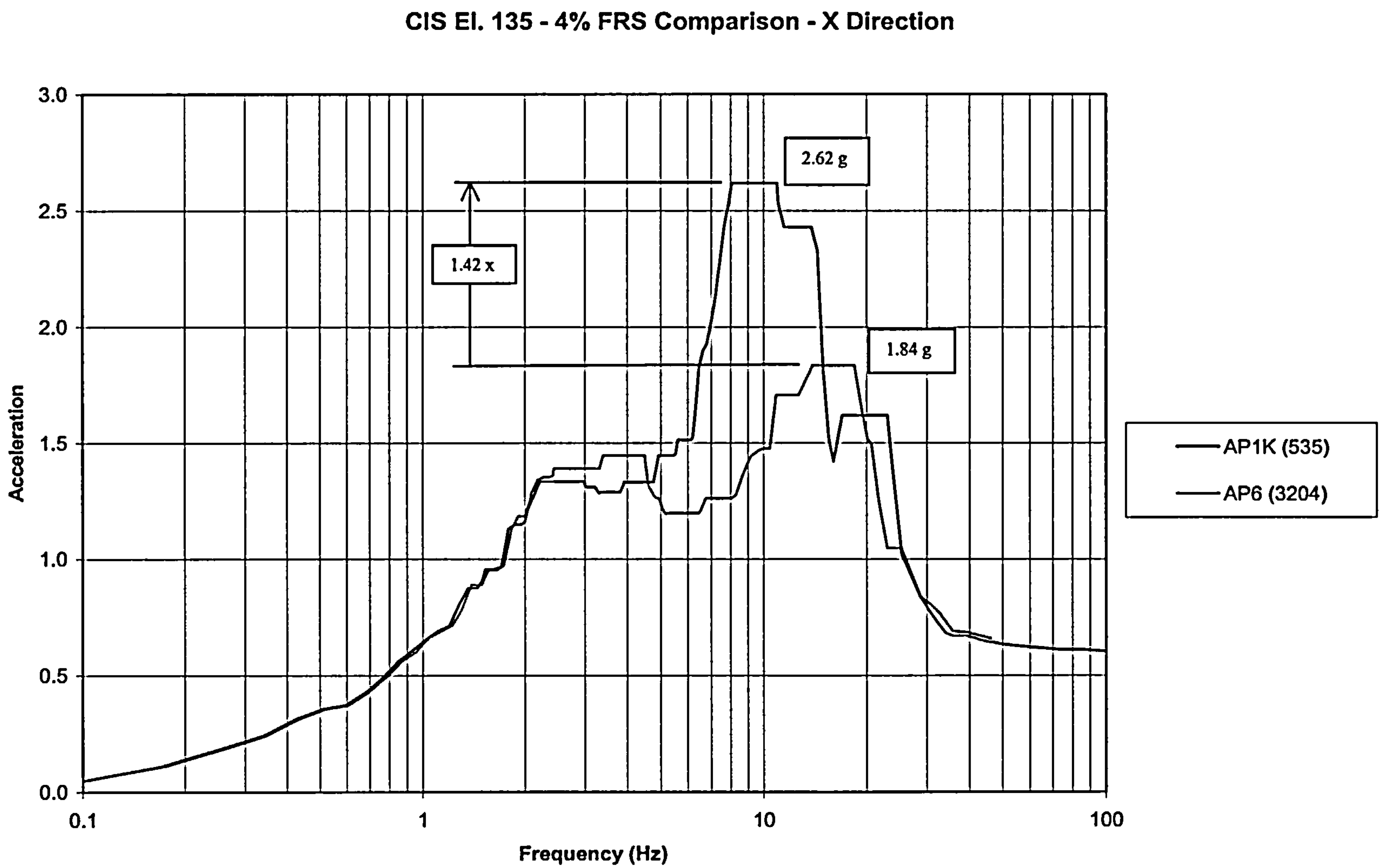


Figure 1 - In-Structure Seismic Response Spectra, Steam Generator Support Elev. 135', (North-South)

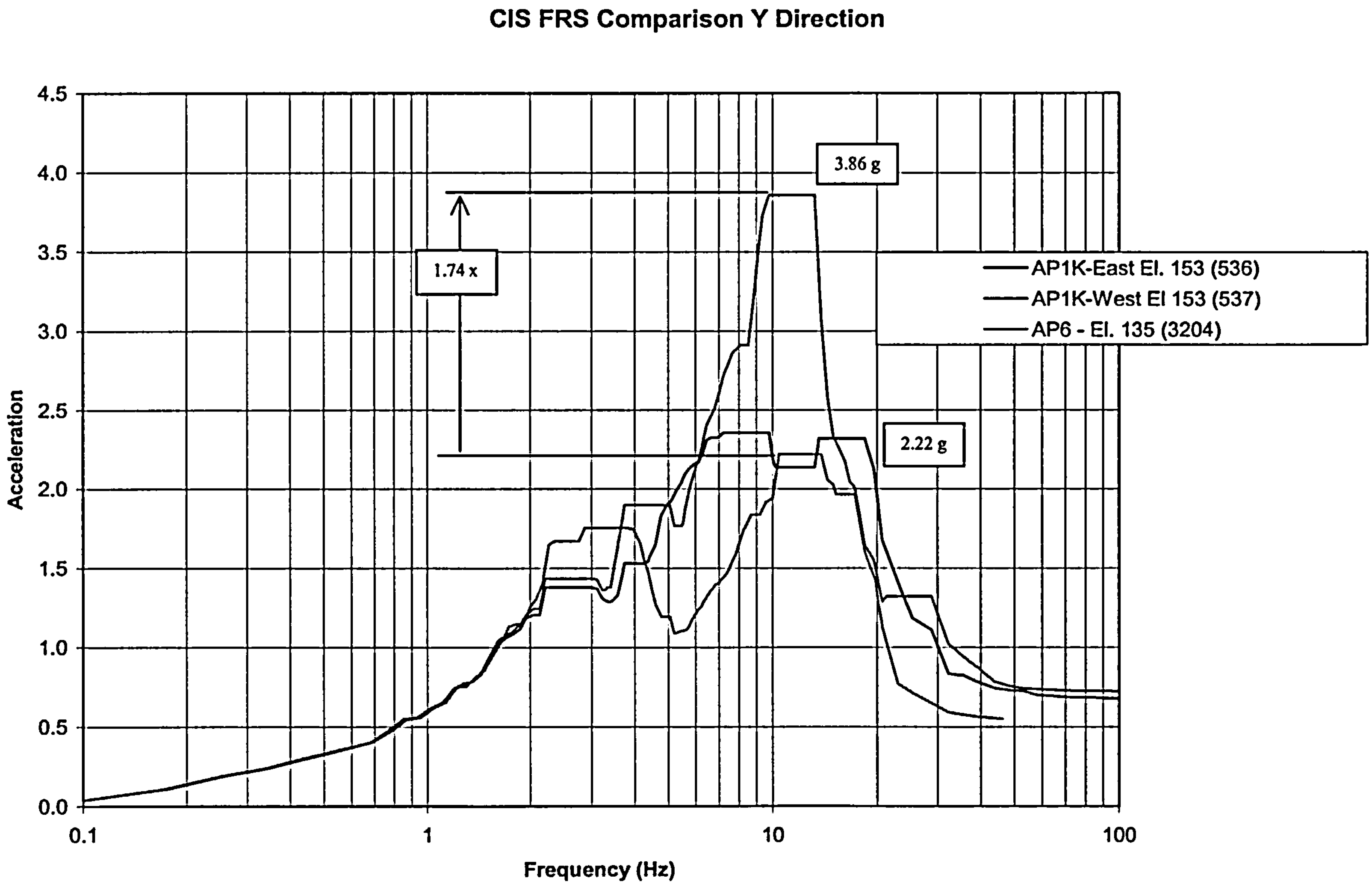


Figure 2 - In-Structure Seismic Response Spectra, Steam Generator Support Elev. 153', (East-West)

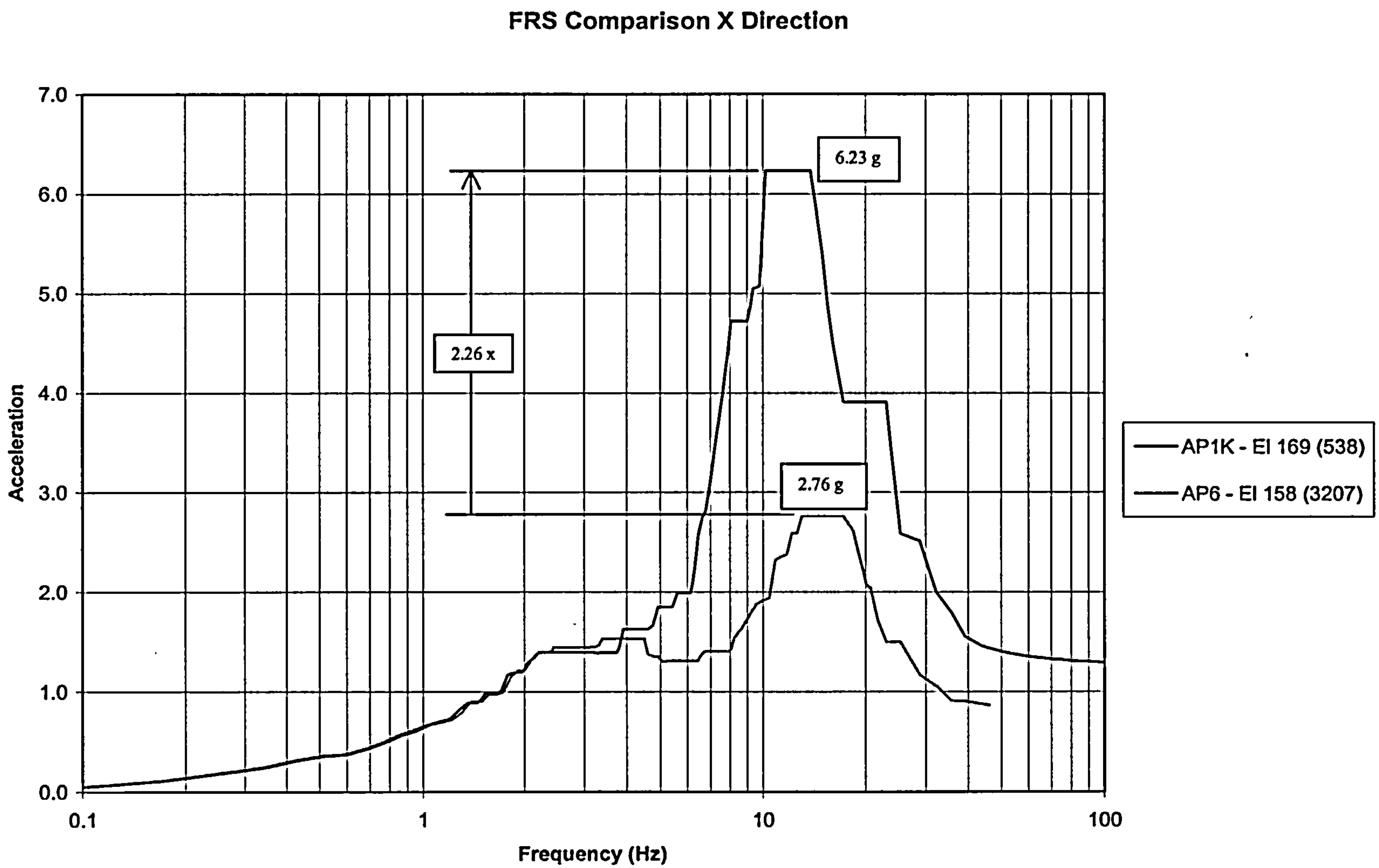


Figure 3 - In-Structure Seismic Response Spectra, Pressurizer Support, (North-South)

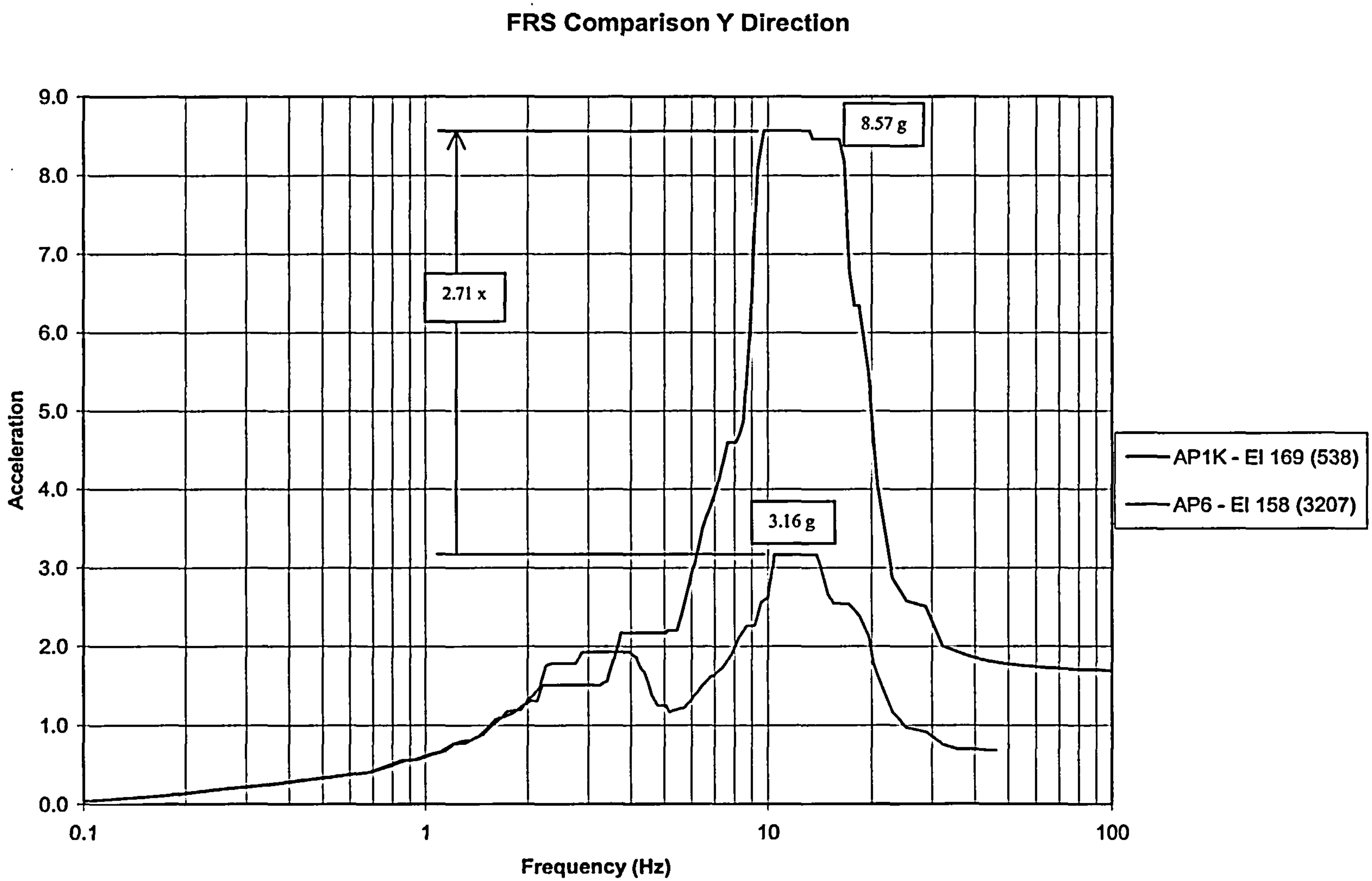


Figure 4 - In-Structure Seismic Response Spectra, Pressurizer Support, (East-West)

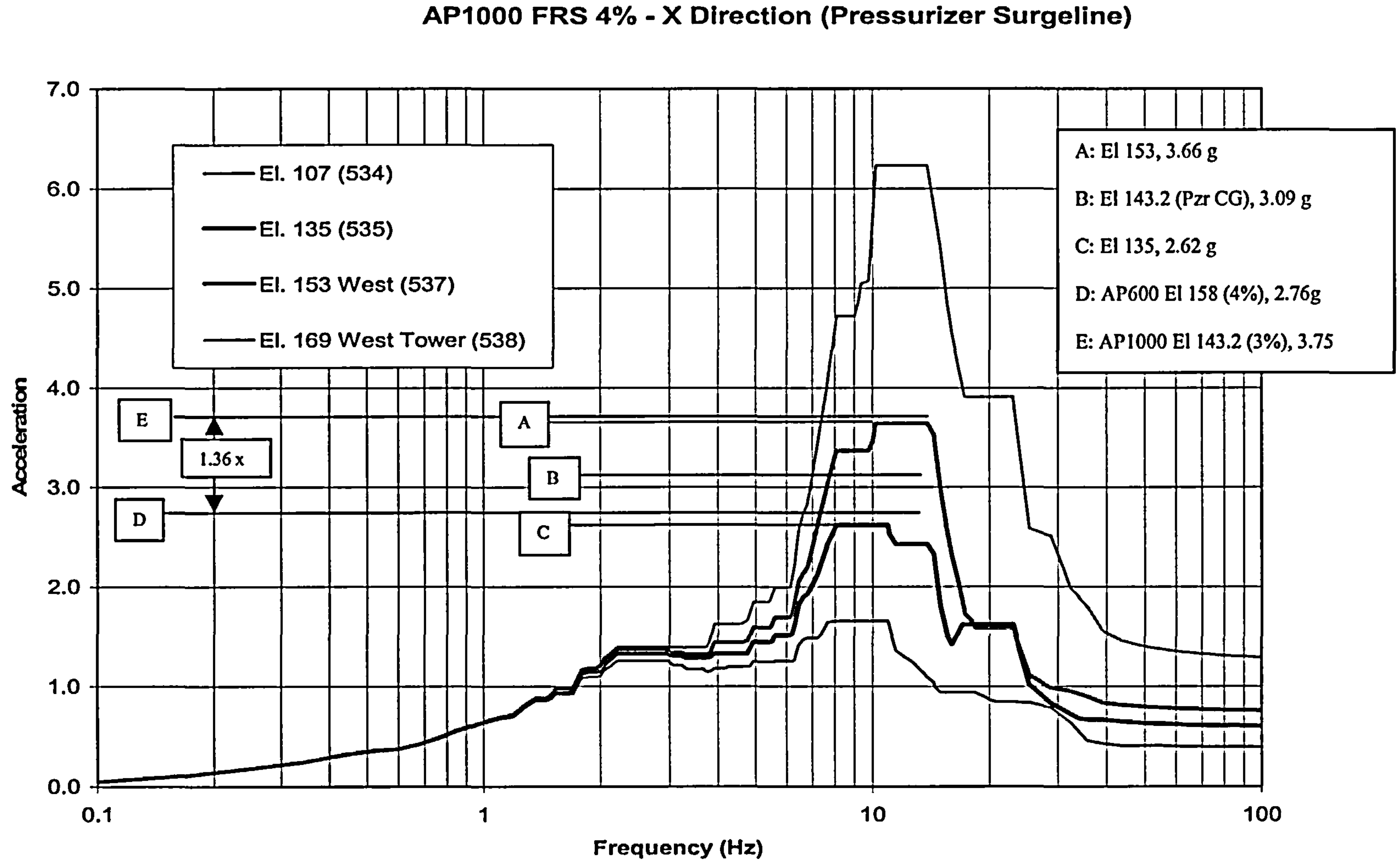


Figure 5 - In-Structure Seismic Response Spectra, Pressurizer Center of Gravity, (North –South)

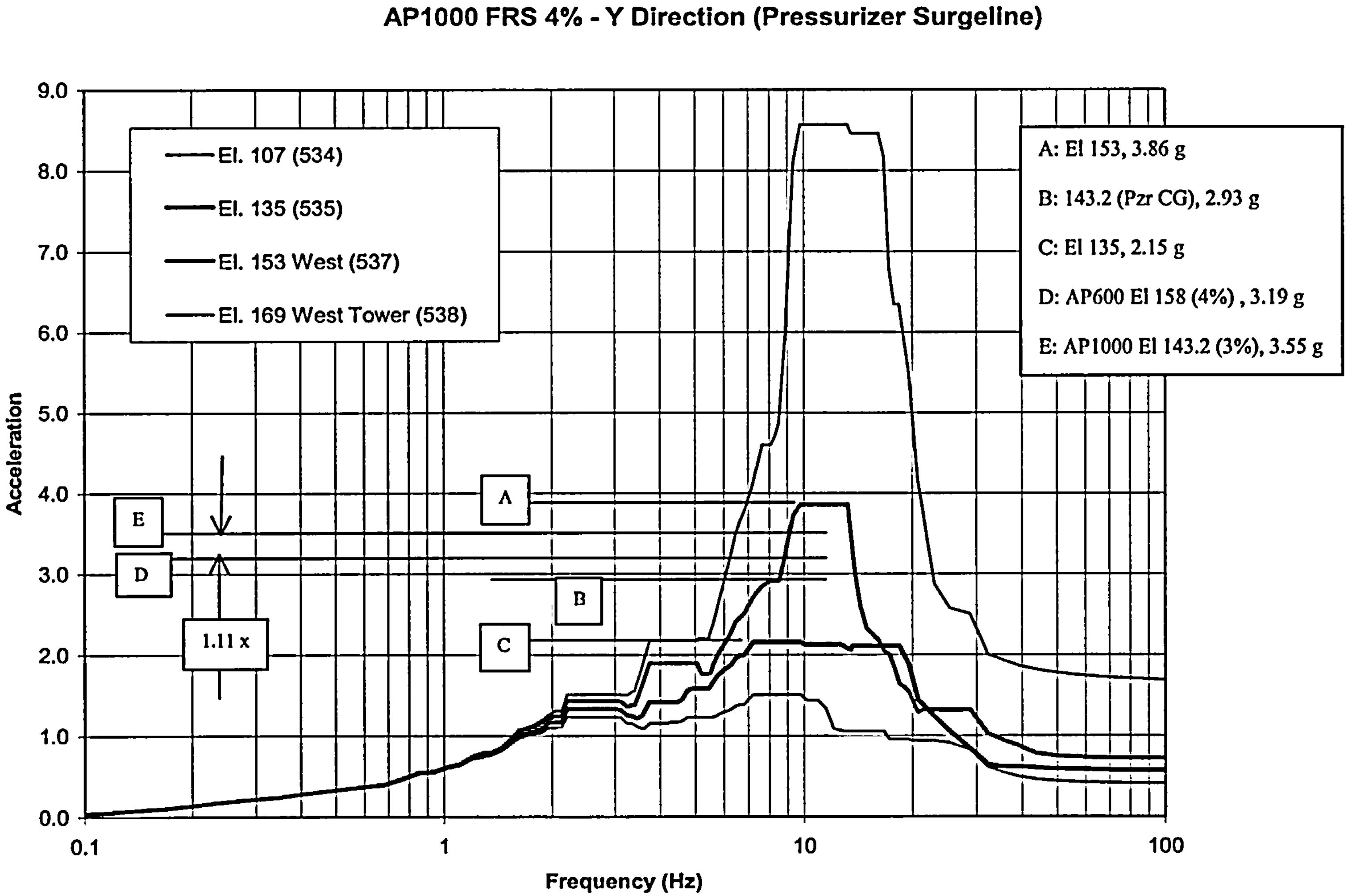


Figure 6 - In-Structure Seismic Response Spectra, Pressurizer Center of Gravity, (East-West)

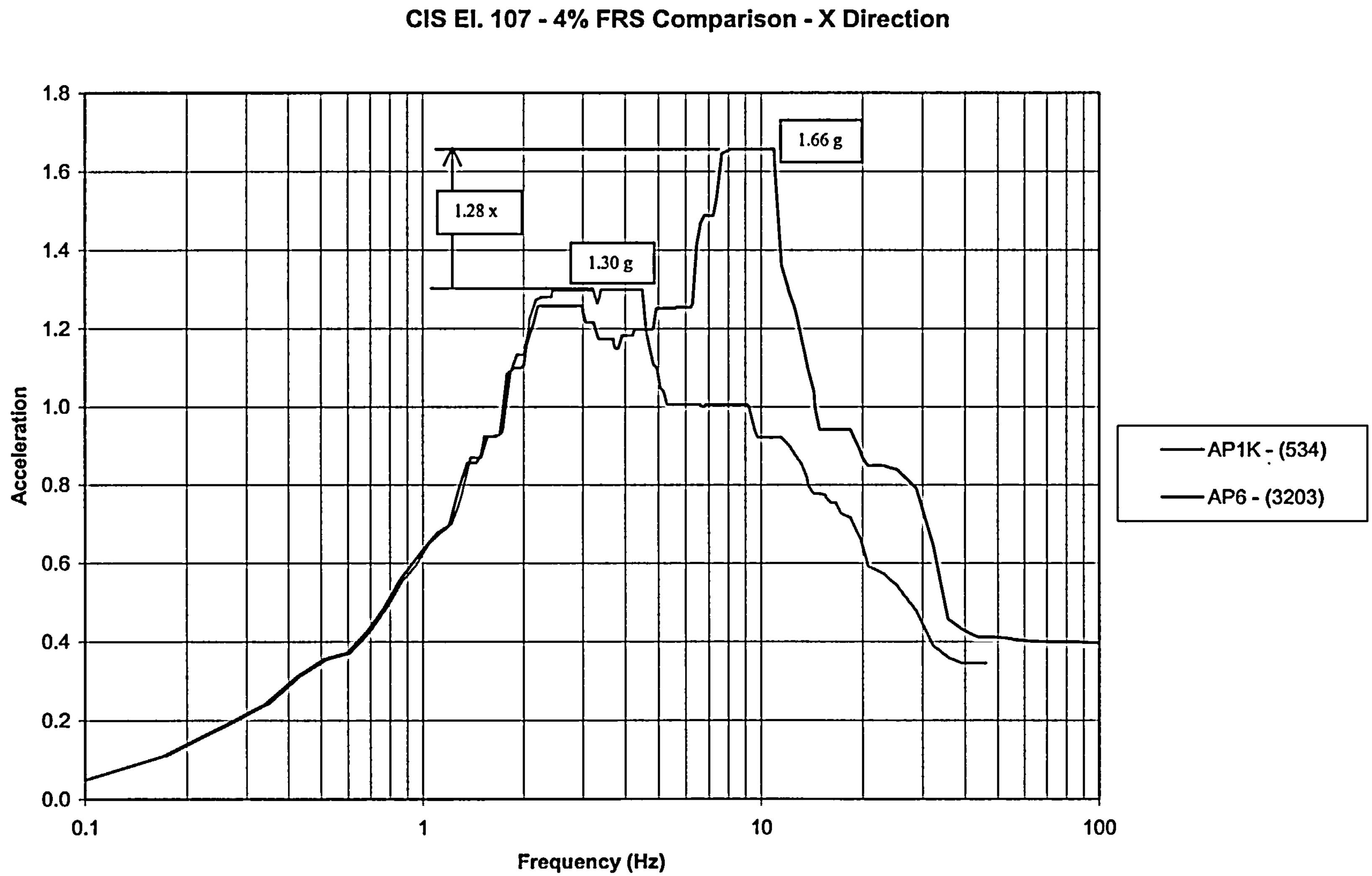


Figure 7 - In-Structure Seismic Response Spectra, Reactor Vessel Support, (North-South)

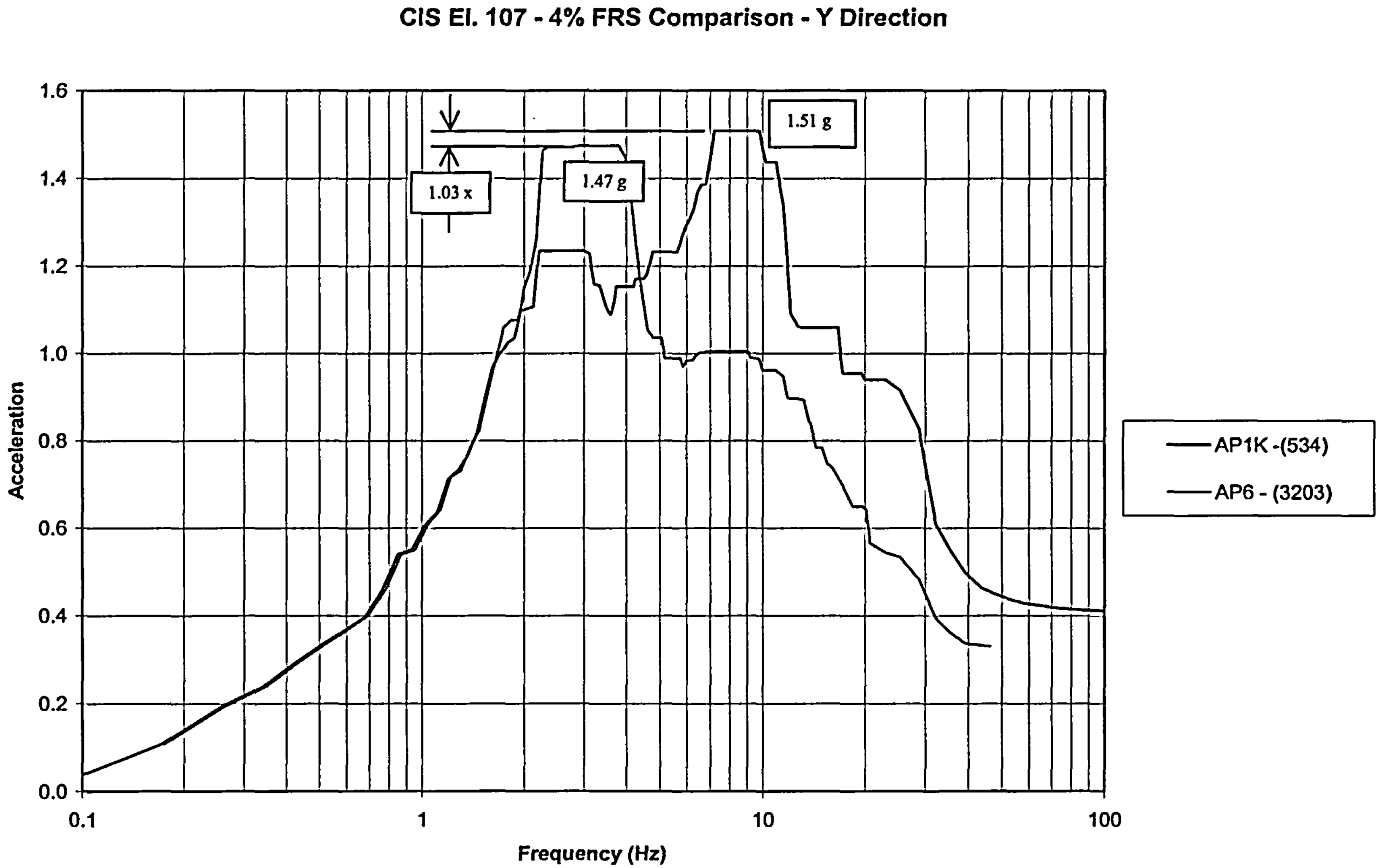
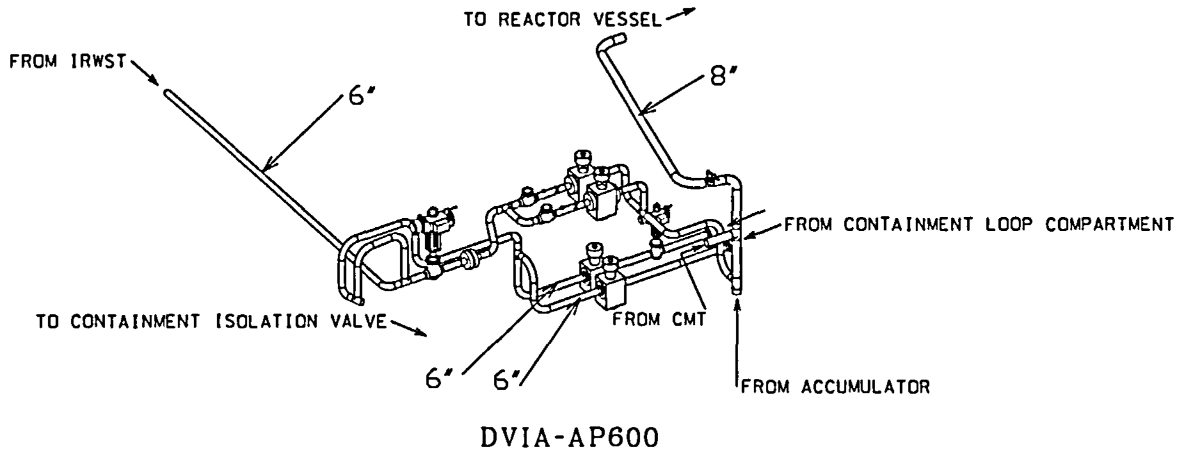


Figure 8 - In-Structure Seismic Response Spectra, Reactor Vessel Support, (East-West)



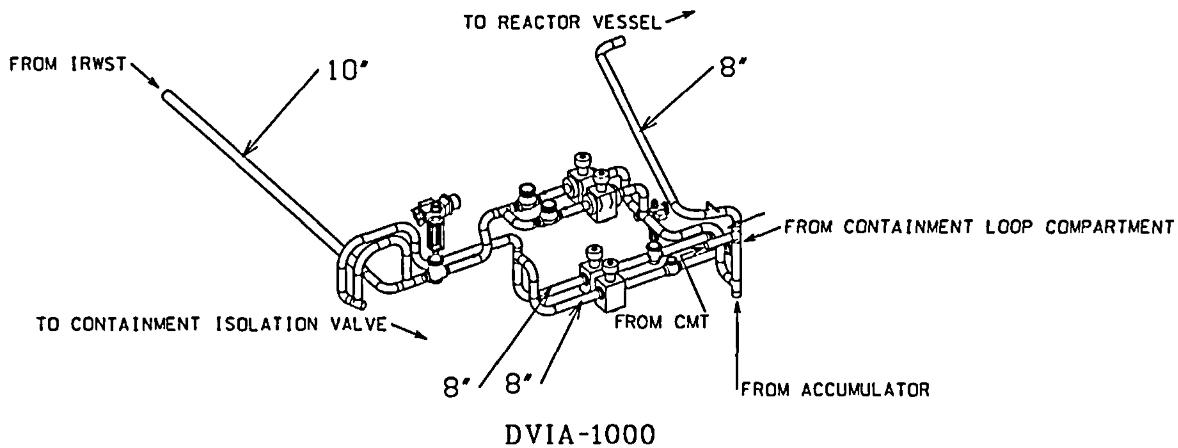


Figure 9 – Isometric View: Comparison of AP600 and AP1000 DVI-A Piping System

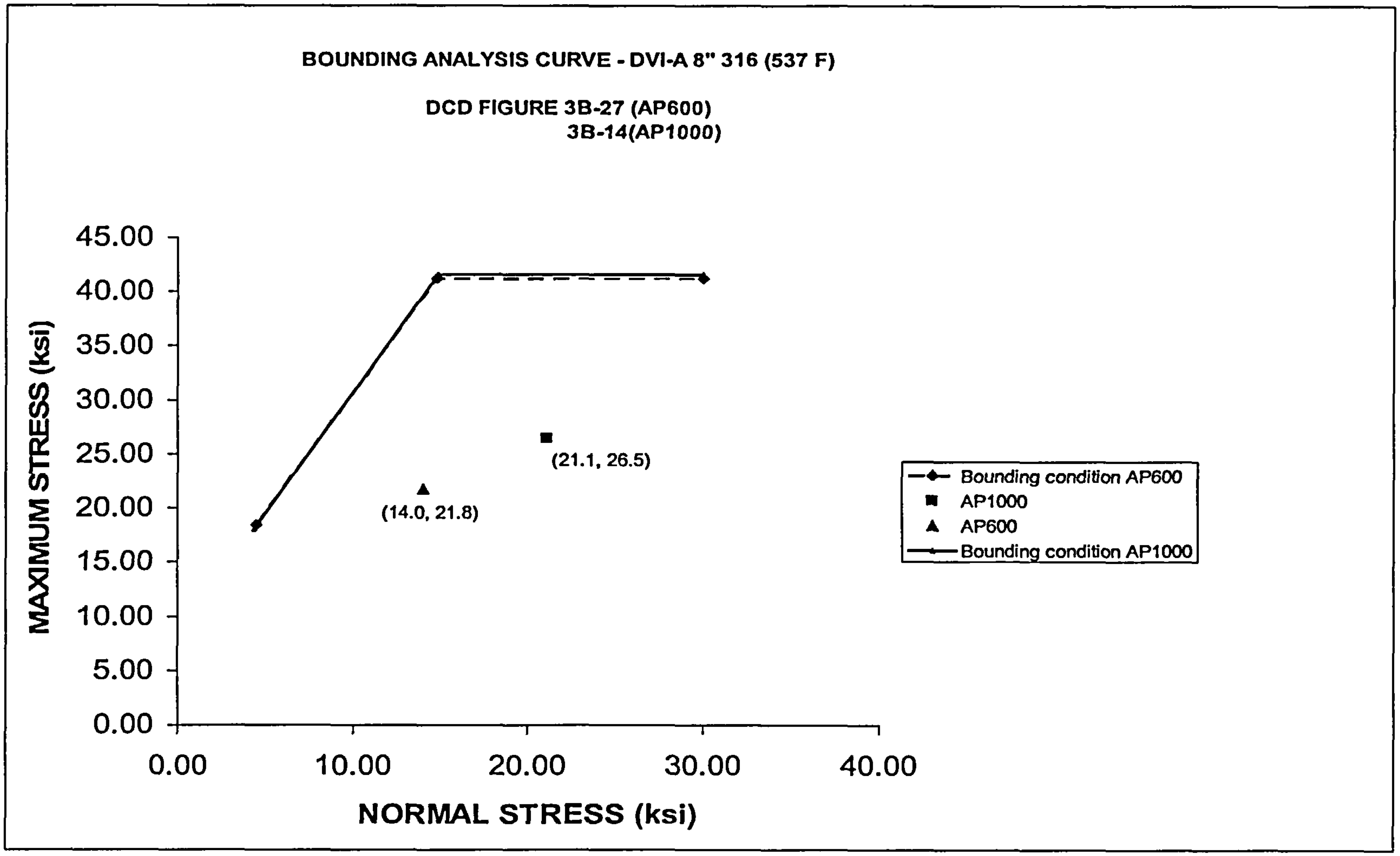


Figure 10 - Bounding Analysis Curve – DVI-A – 8” (316 SS, 537 °F)

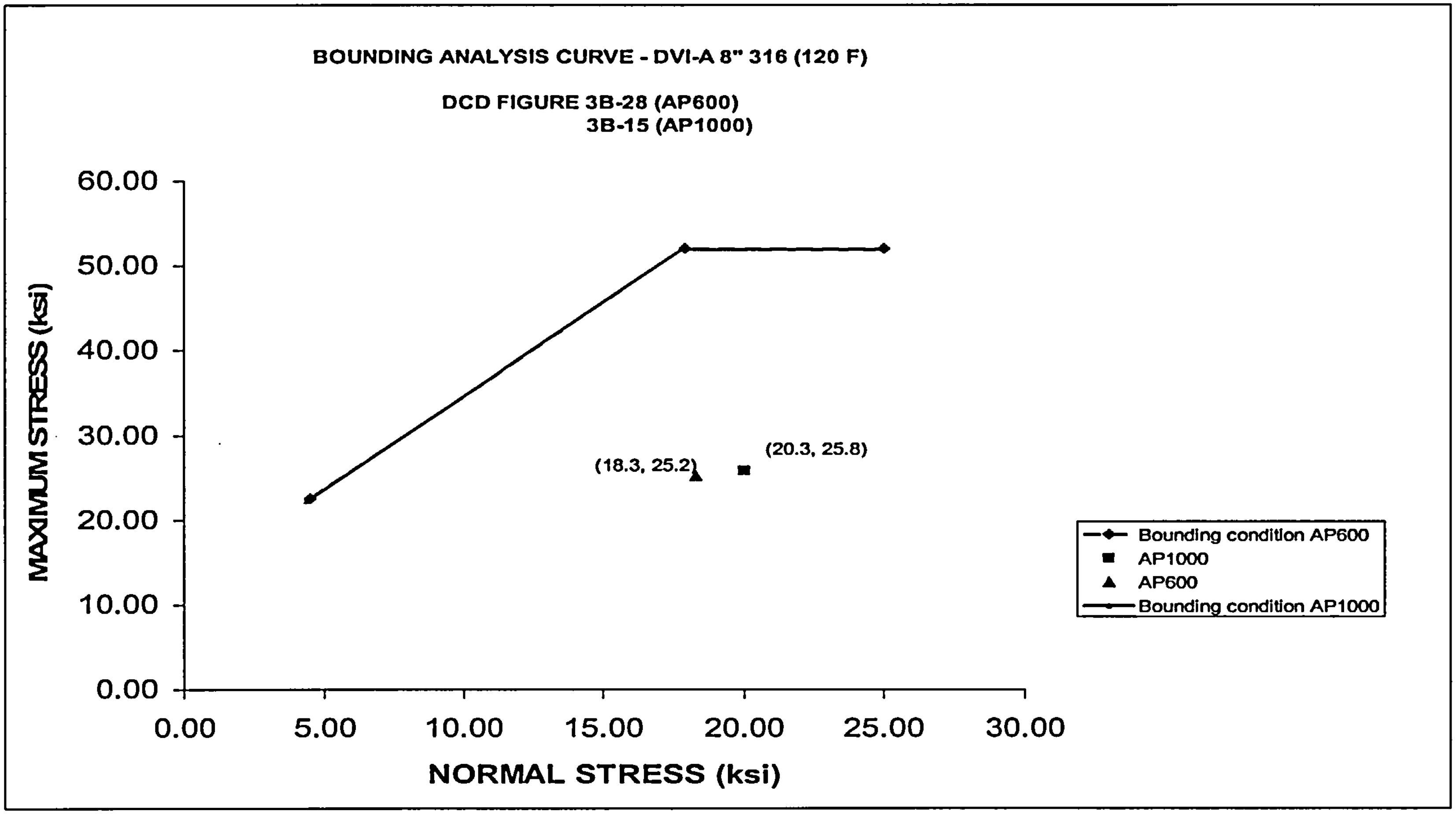


Figure 11 - Bounding Analysis Curve – DVI-A – 8" (316 SS, 120 °F)

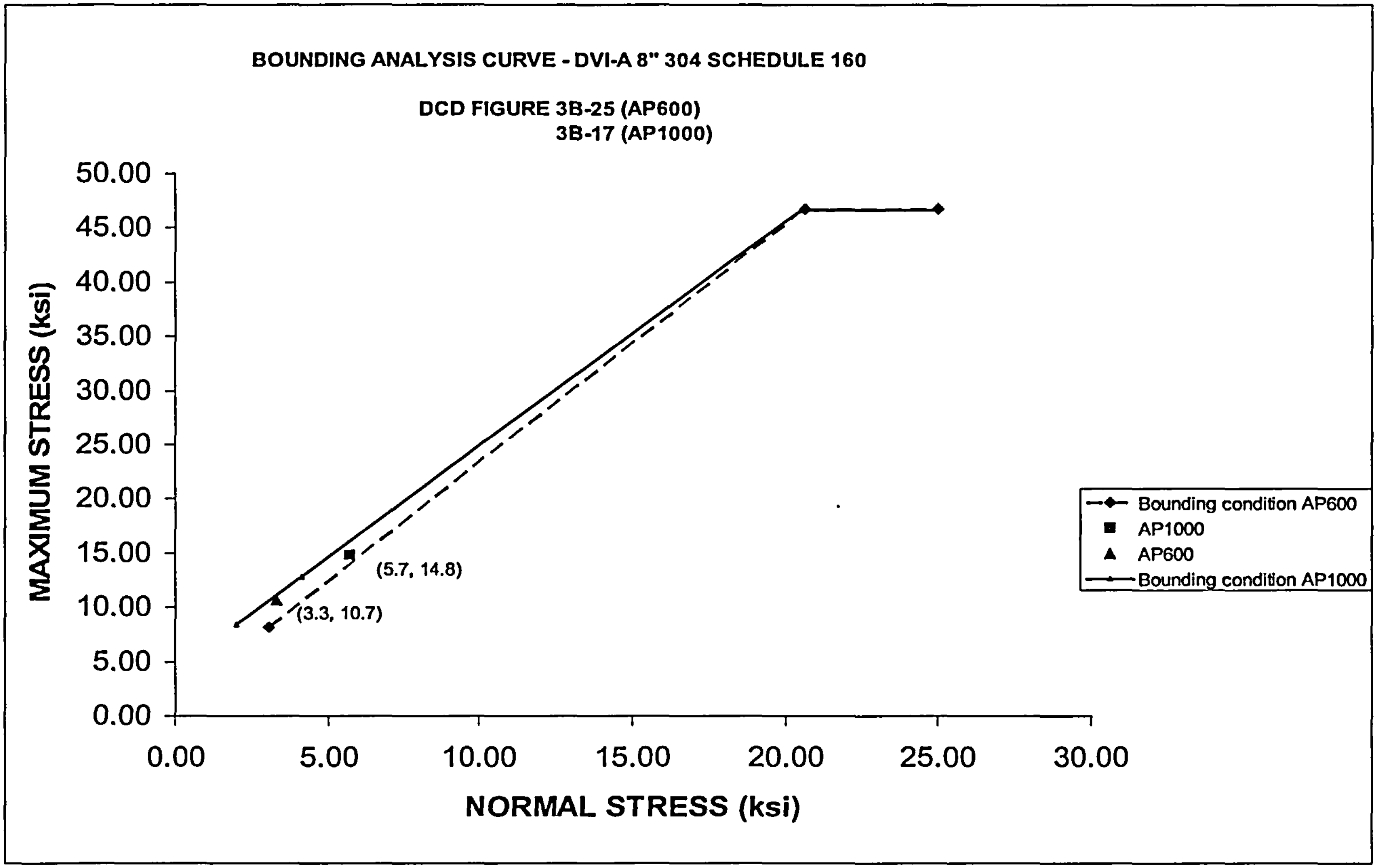


Figure 12 - Bounding Analysis Curve – DVI-A – 8" (304 SS)

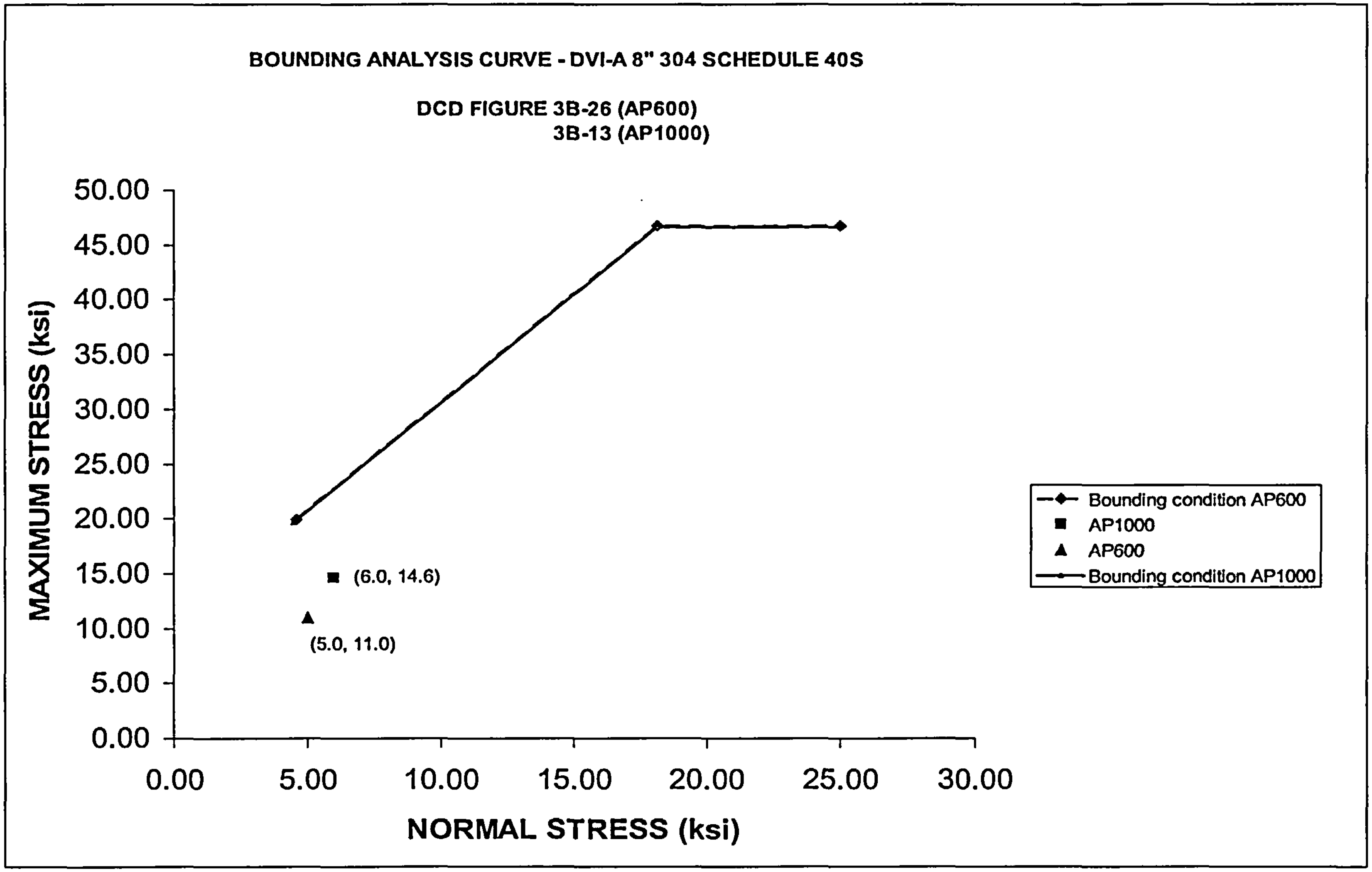


Figure 13 - Bounding Analysis Curve – DVI-A – 8" (Sch 40S)

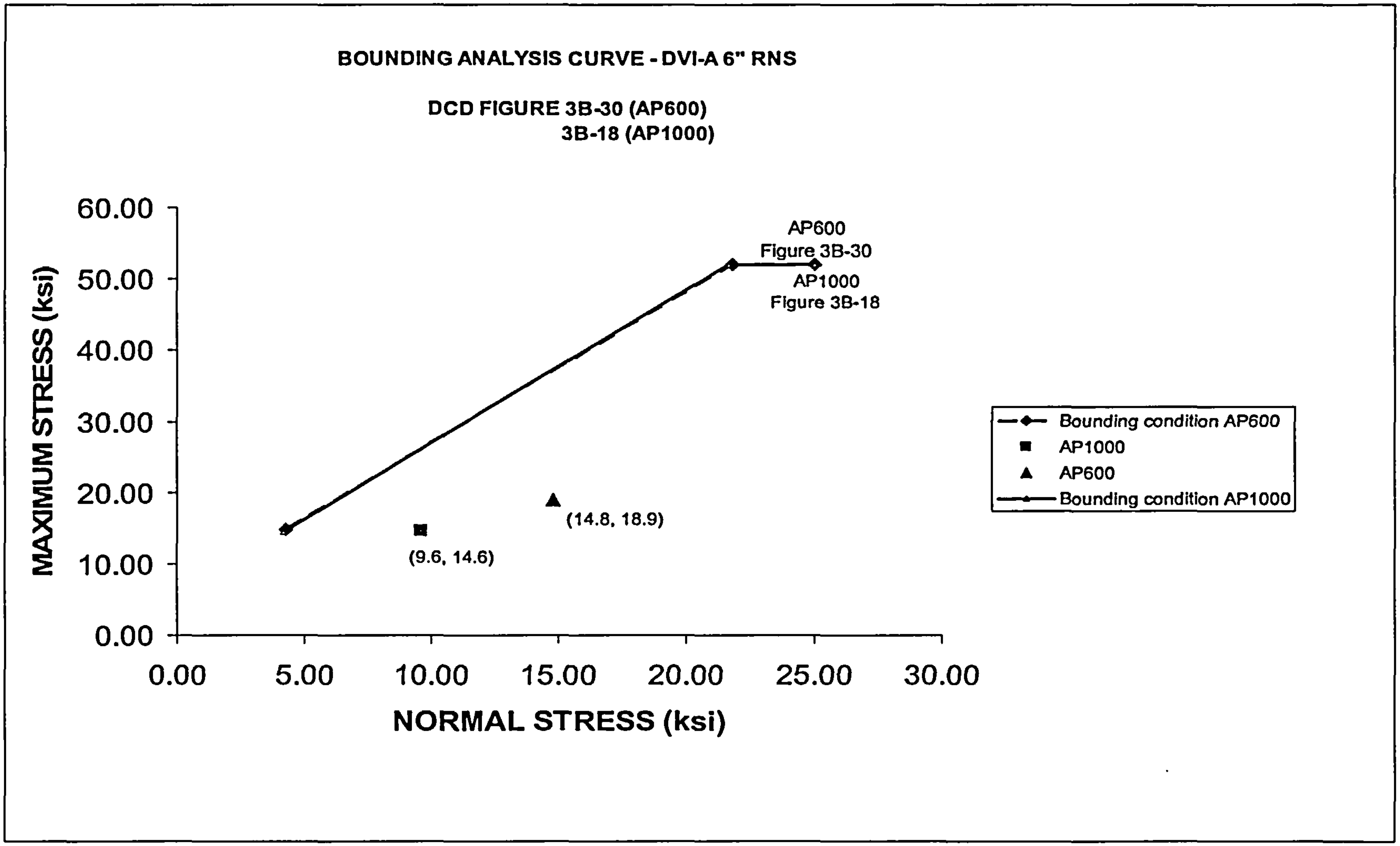


Figure 14 - Bounding Analysis Curve – DVI-A – 6" RNS

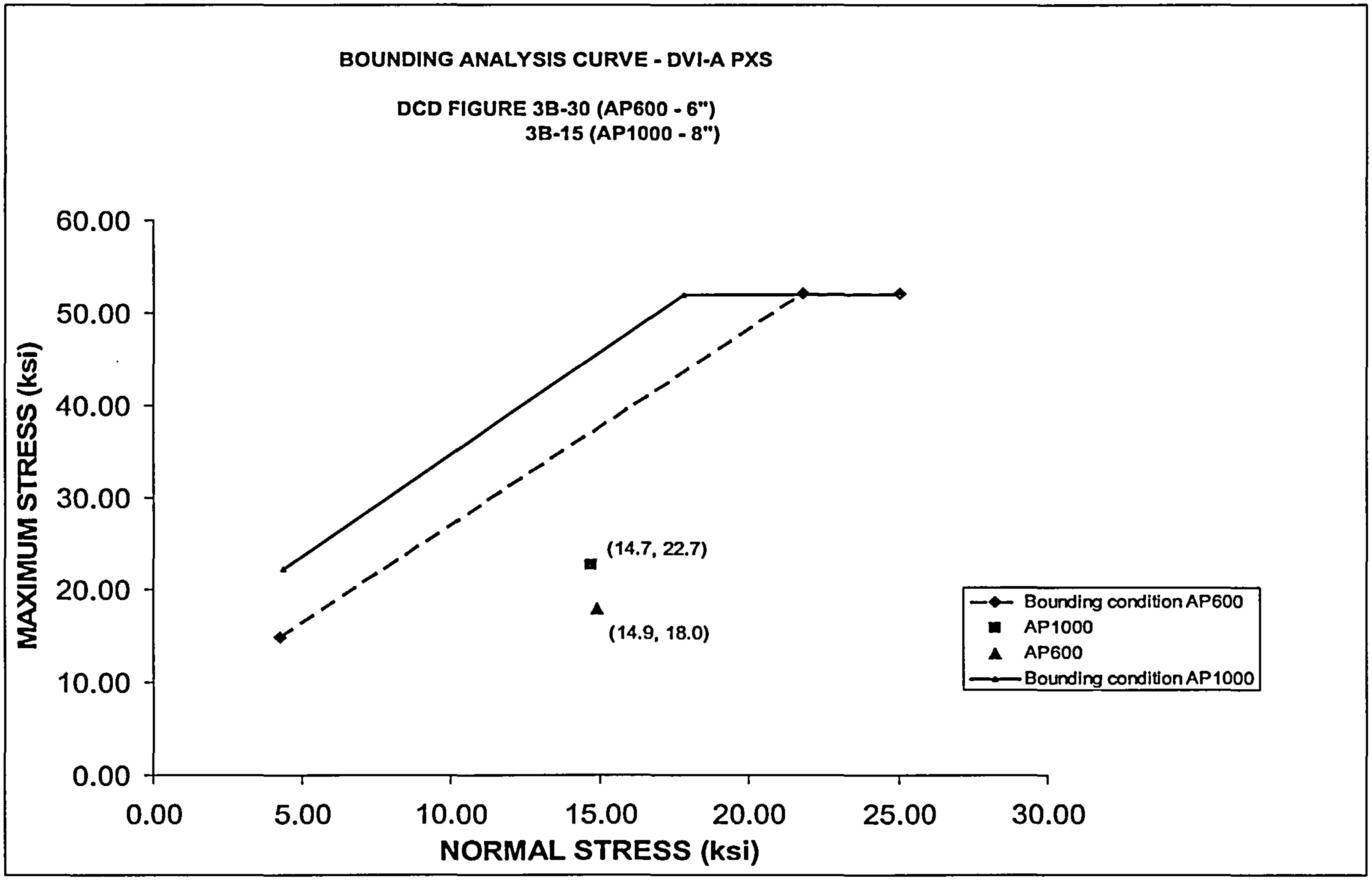


Figure 15 - Bounding Analysis Curve – DVI-A – 8" PXS

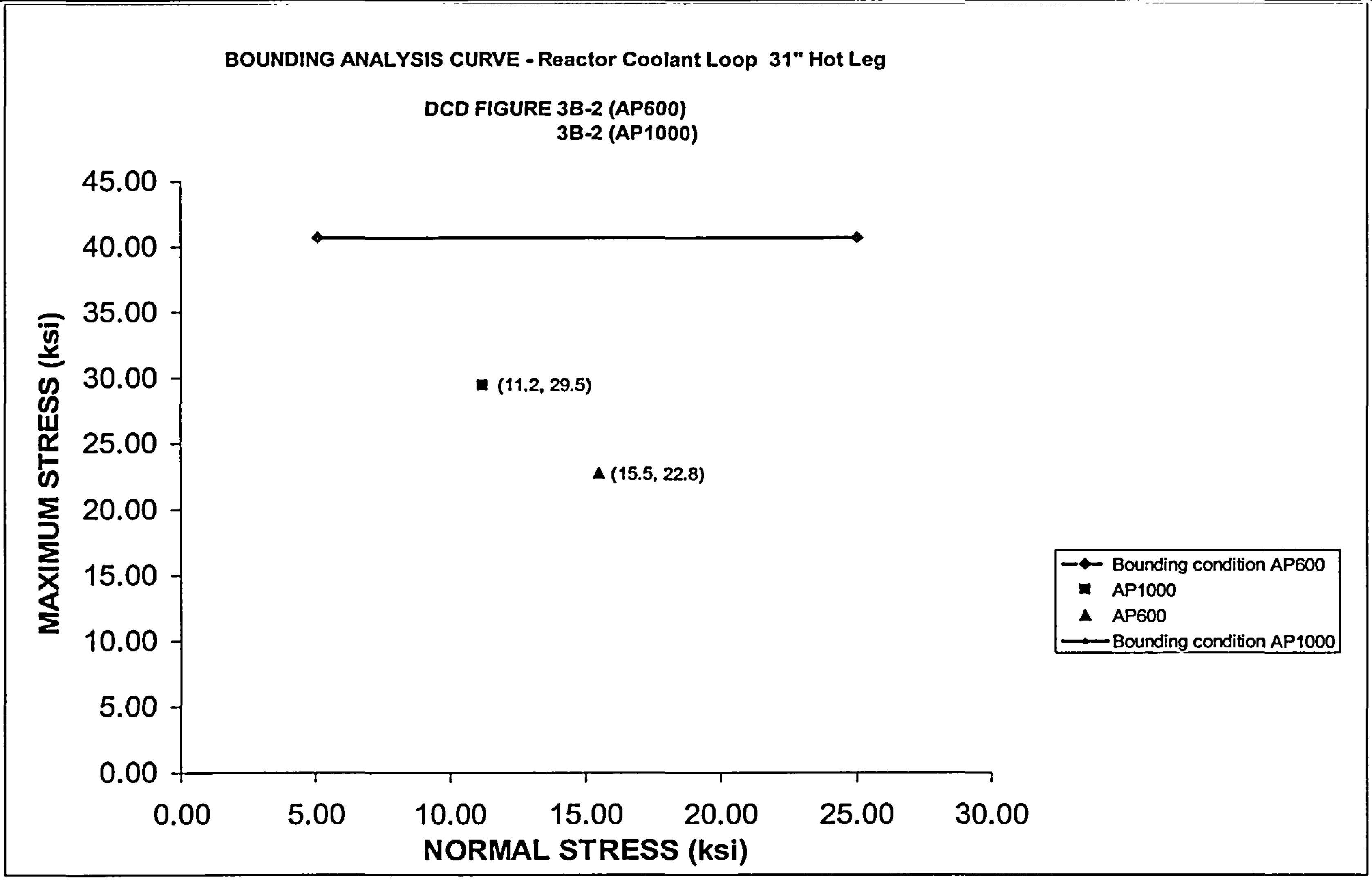


Figure 16 - Bounding Analysis Curve – Primary Loop Hot Leg – 31”

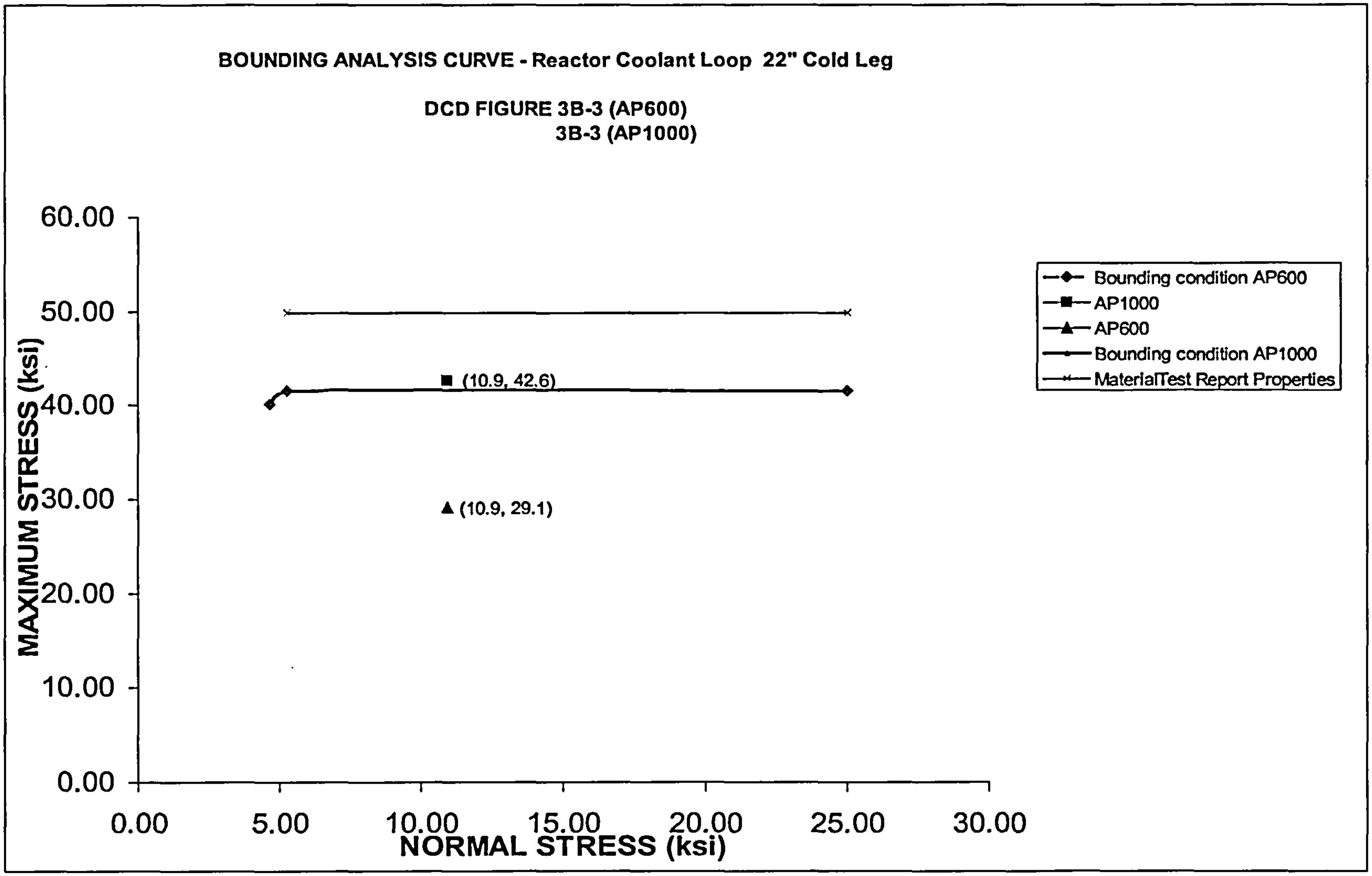


Figure 17 - Bounding Analysis Curve – Primary Loop Cold Leg – 22"

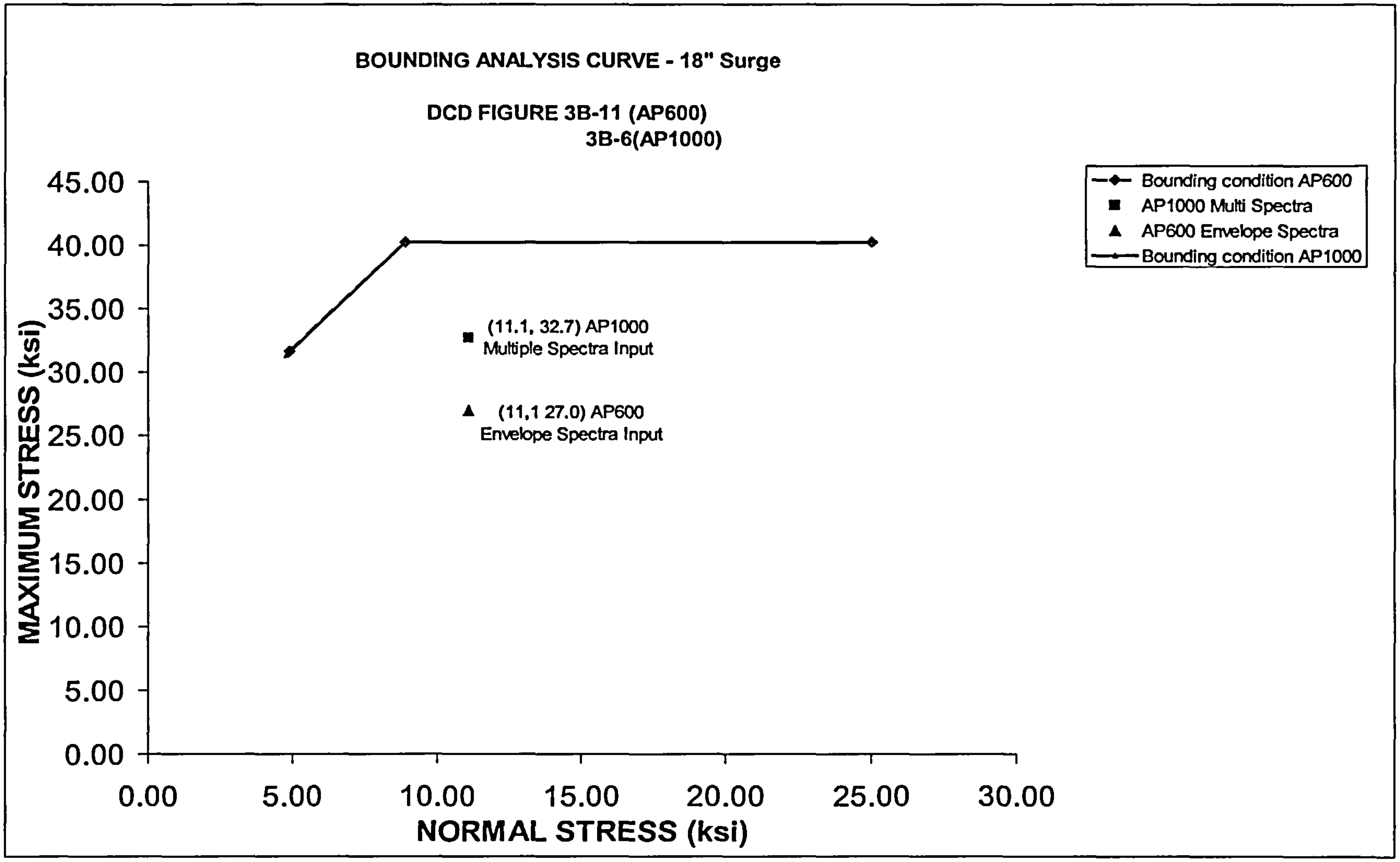


Figure 18 - Bounding Analysis Curve – Pressurizer Surgeline – 18”

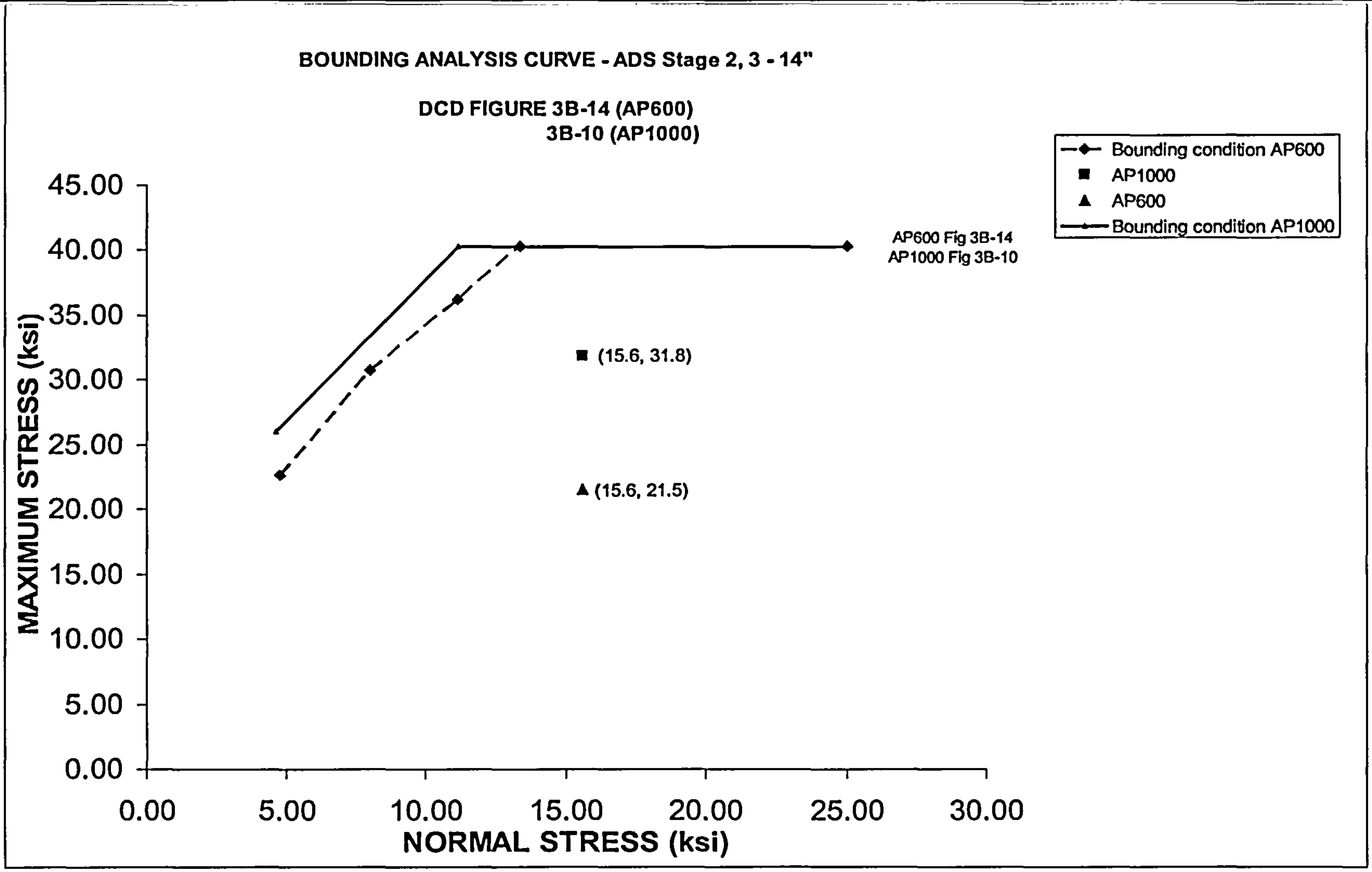


Figure 19 - Bounding Analysis Curve – ADS Stage 2 and 3 – 14”

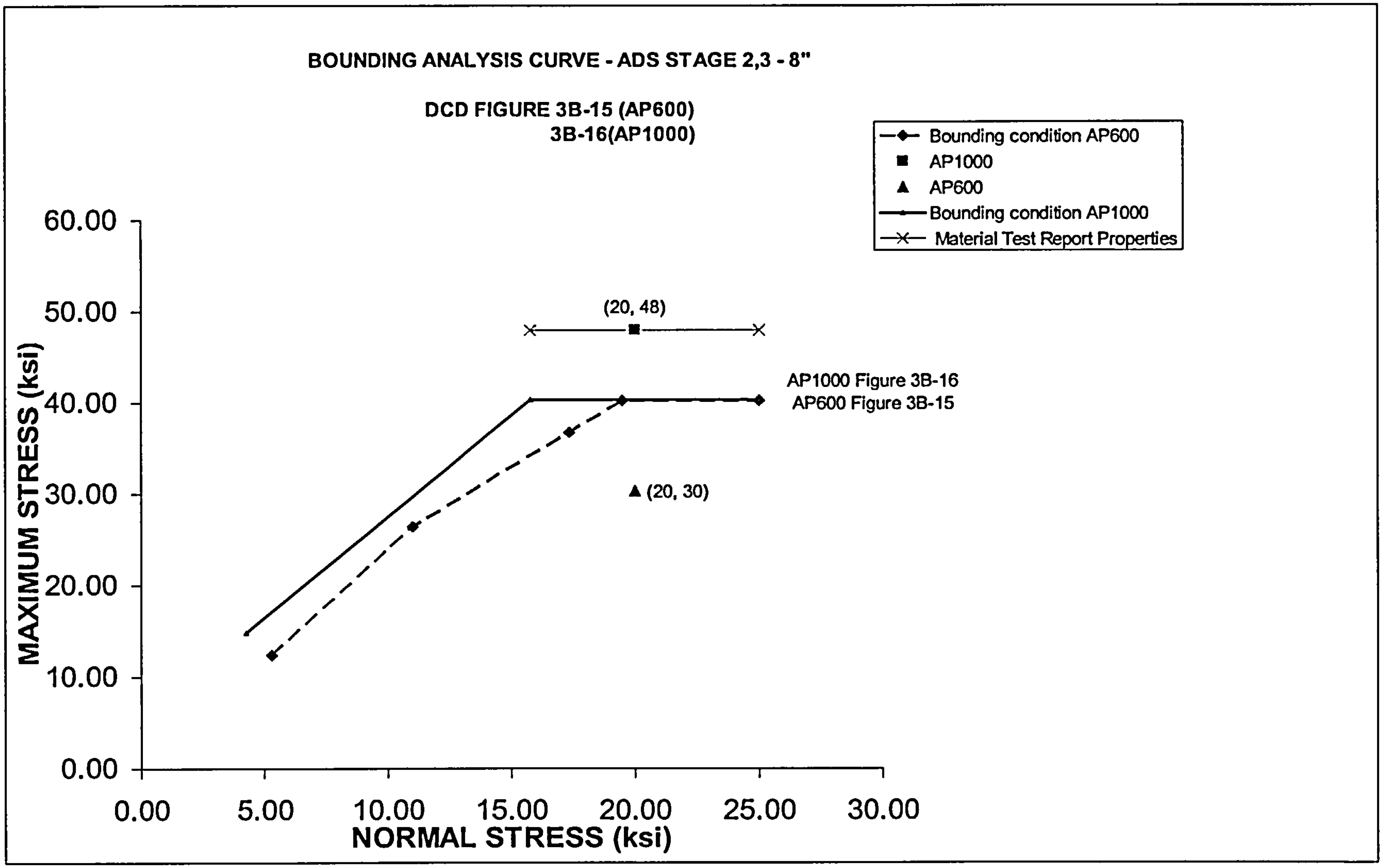


Figure 20 - Bounding Analysis Curve – ADS Stage 2 and 3 – 8"

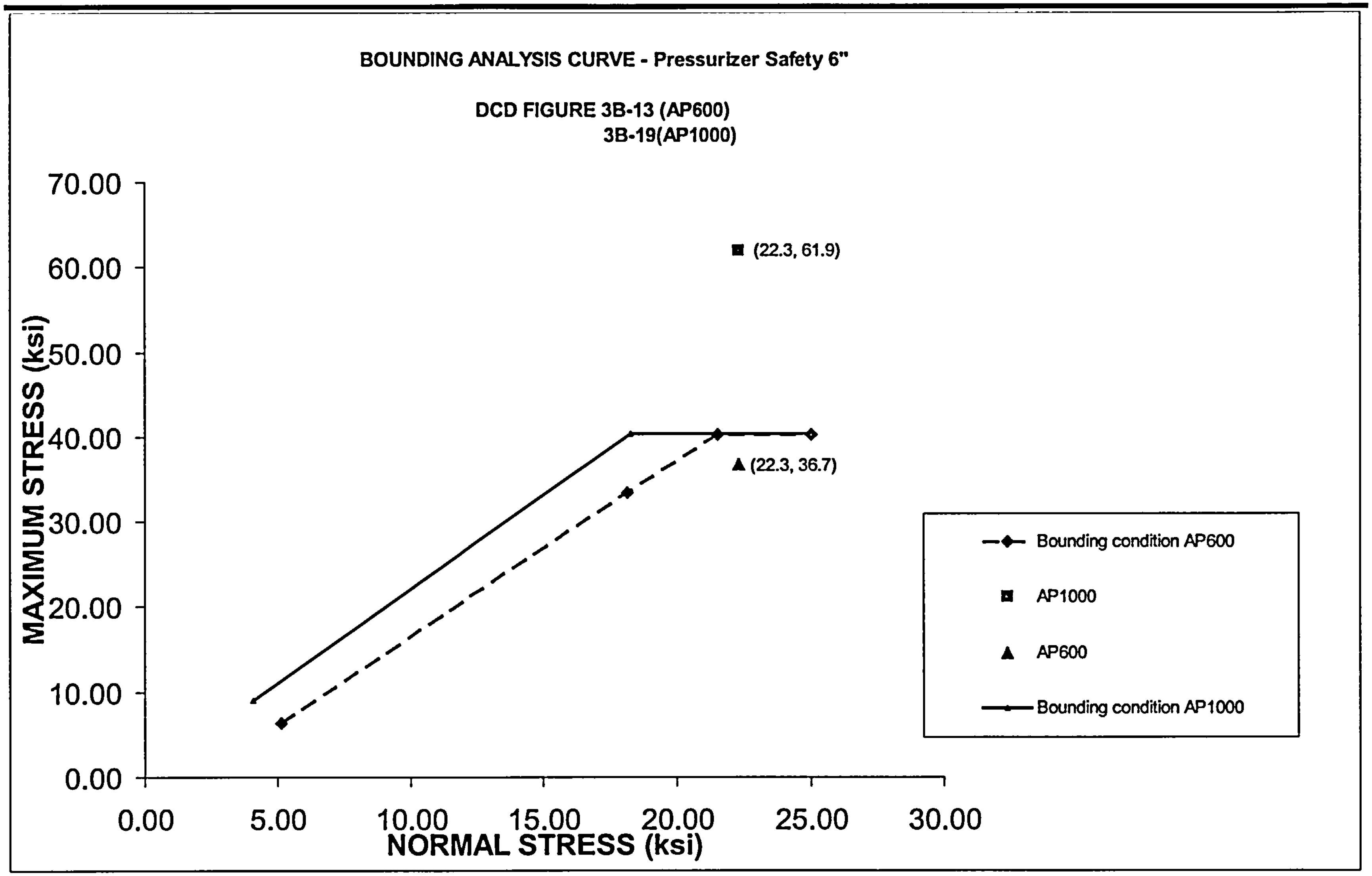


Figure 21 - Bounding Analysis Curve – Pressurizer Safety – 6"

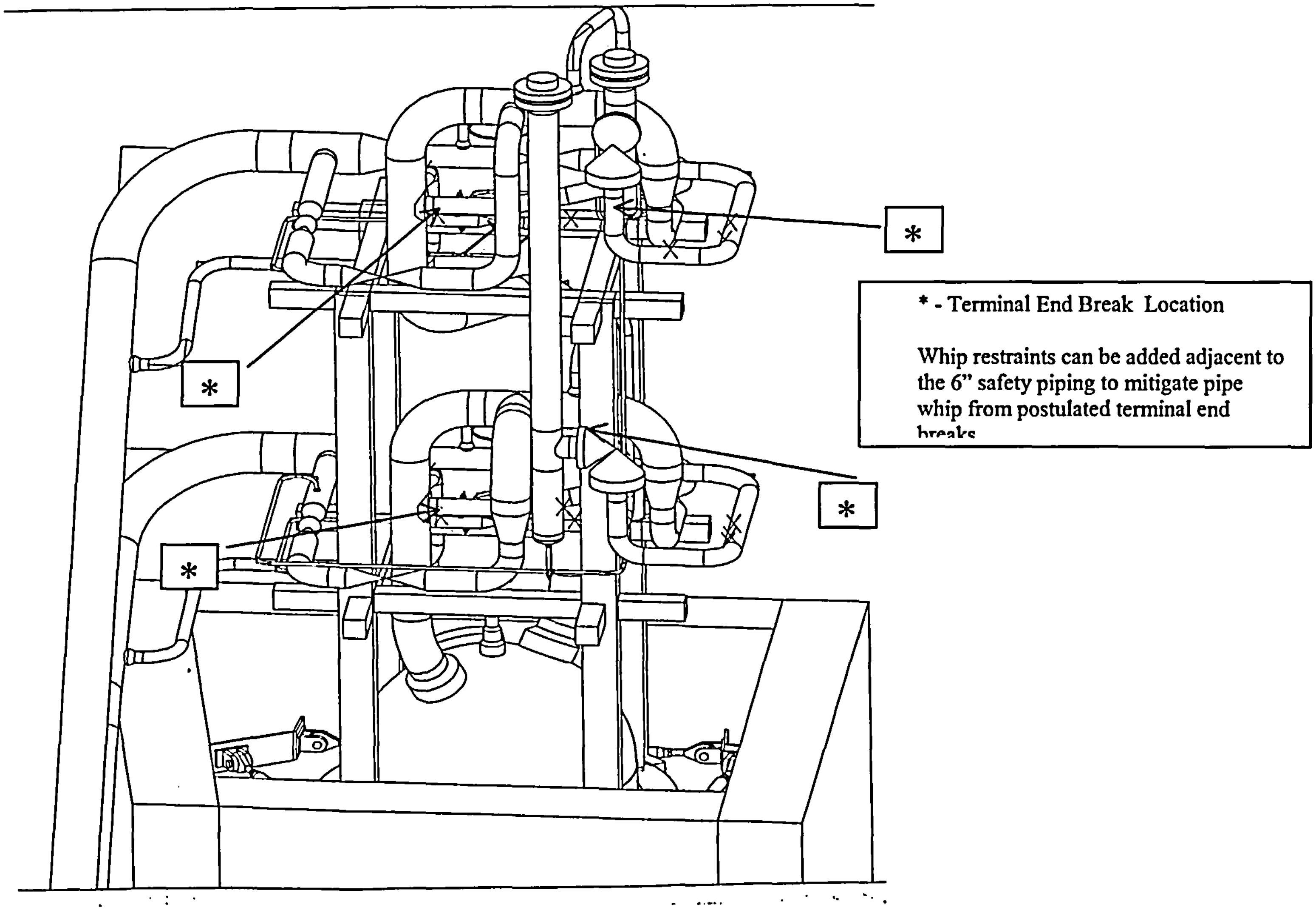
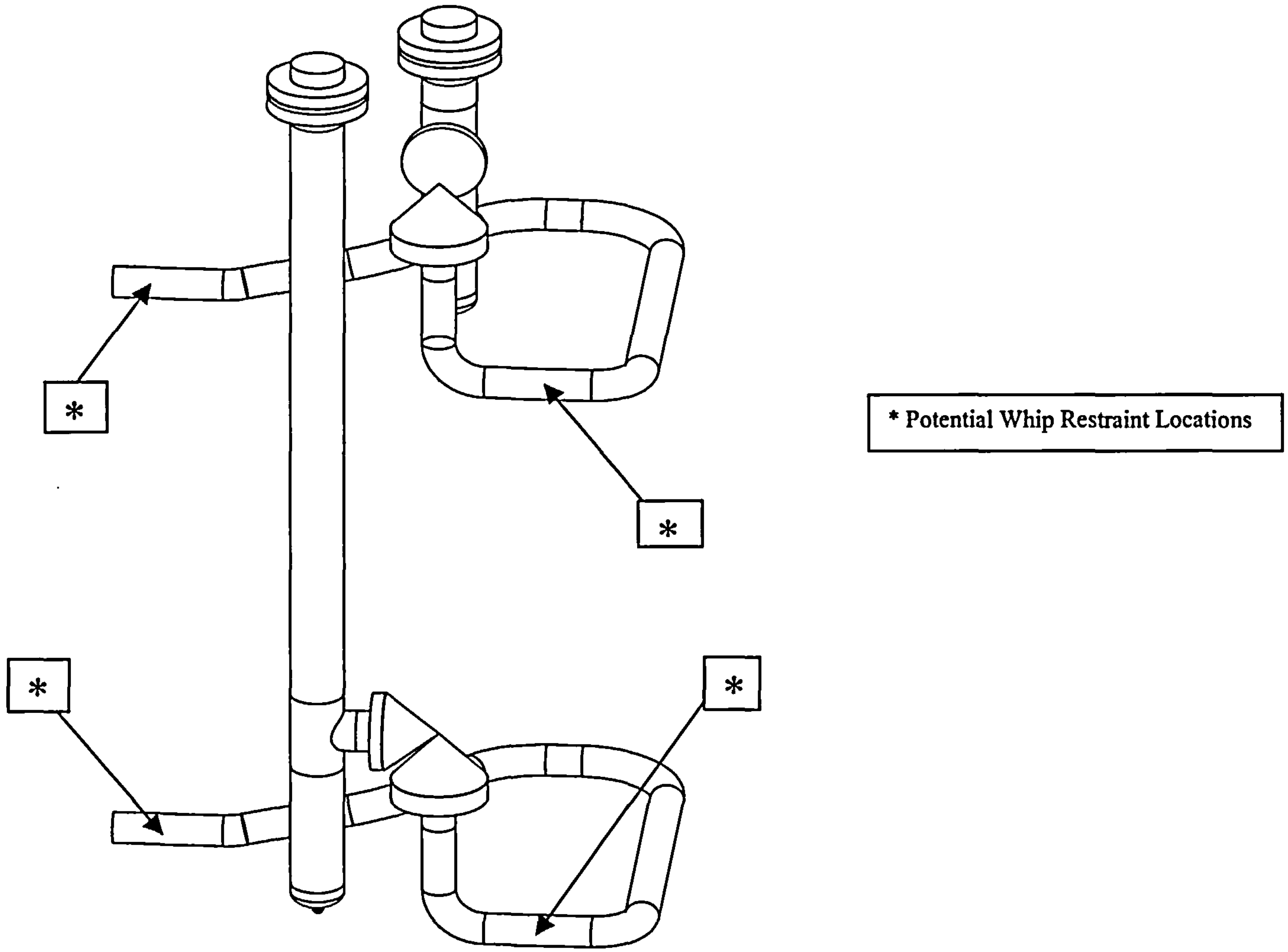


Figure 22 - Pressurizer Safety Valve Inlet Pipe Break Protection (Sheet 1 of 2)



-Figure 22 - Pressurizer Safety Valve Inlet Pipe Break Protection (Sheet 2 of 2)

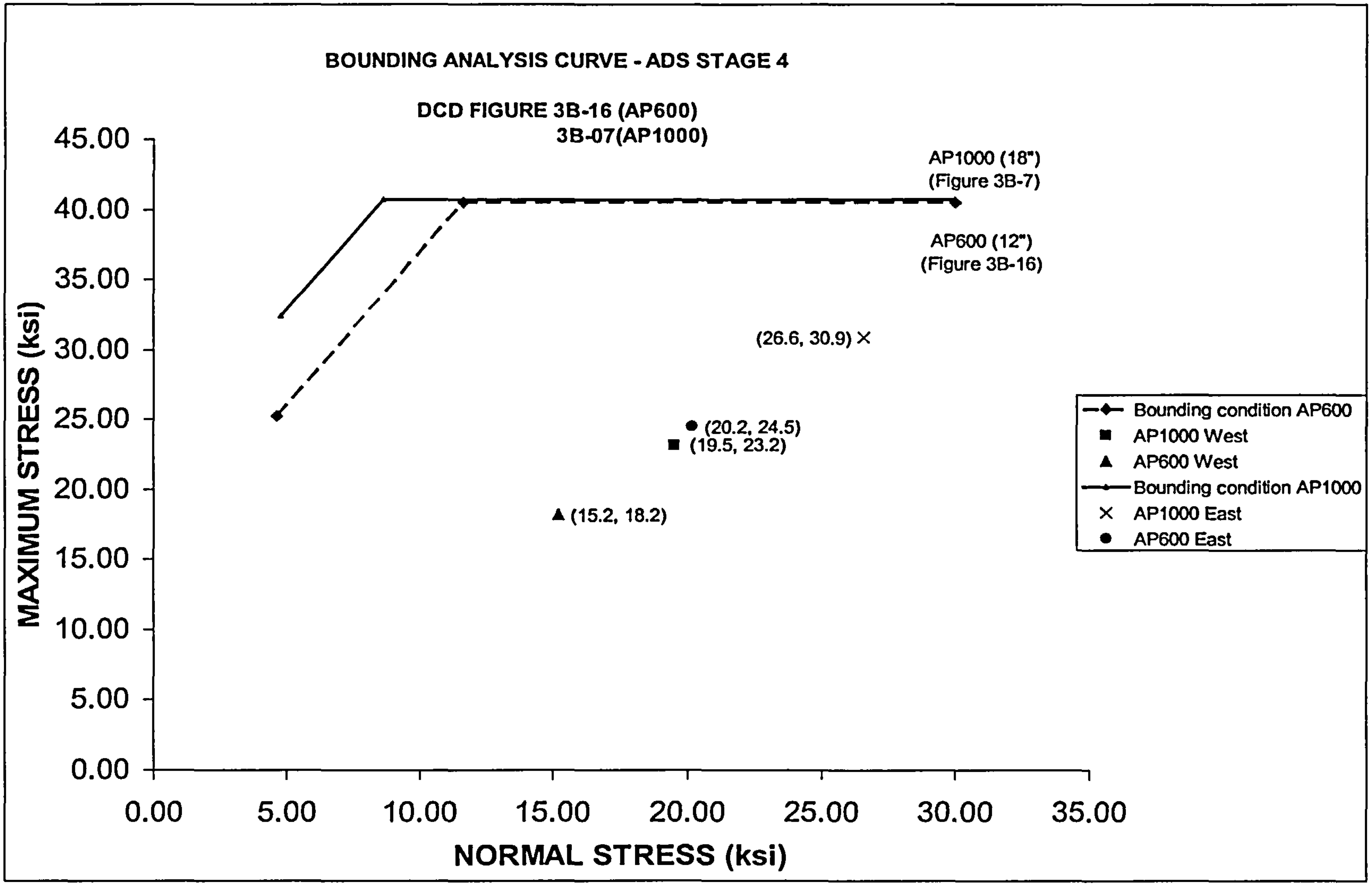


Figure 23 - Bounding Analysis Curve – ADS Stage 4 – 18"

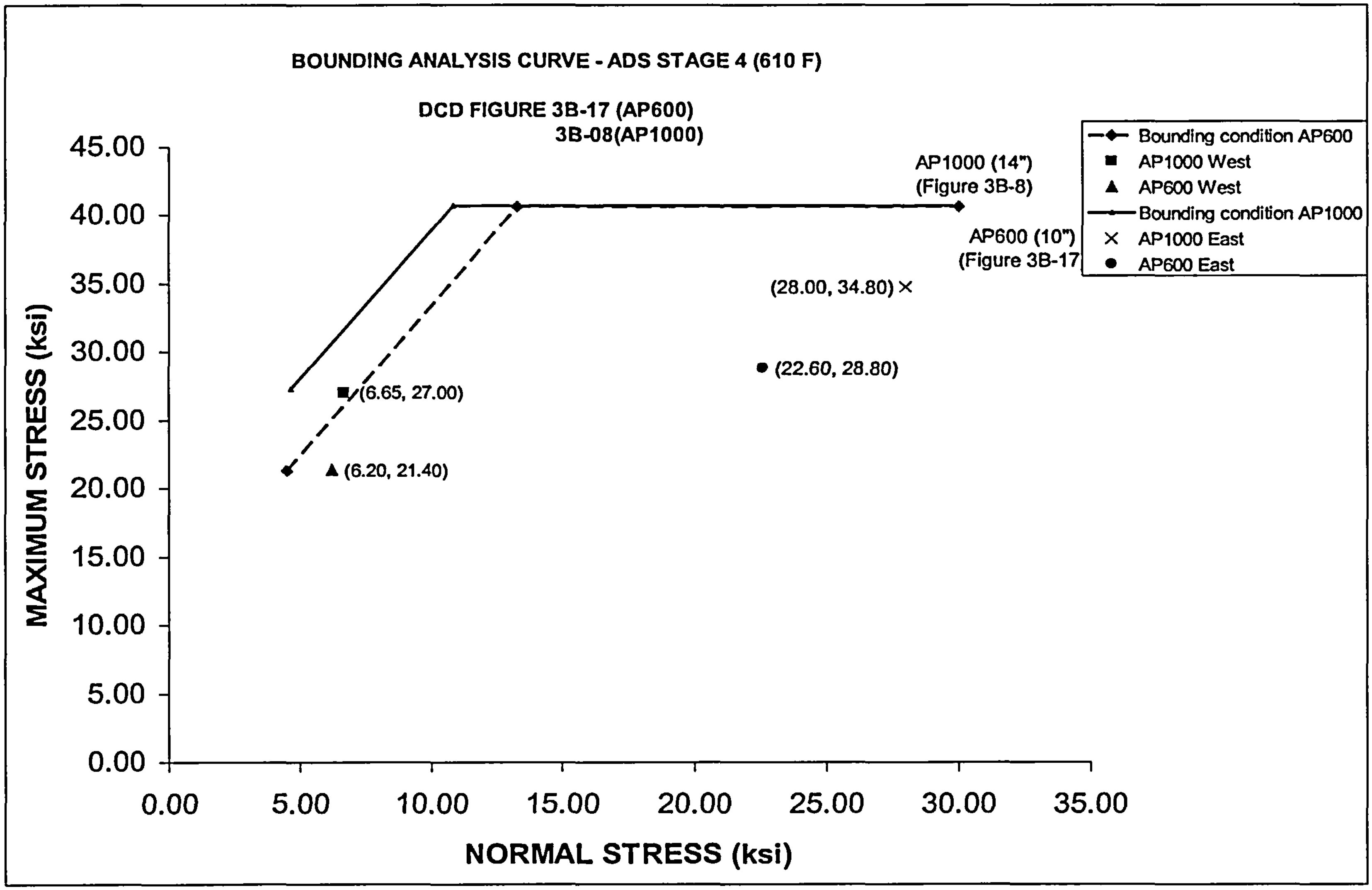


Figure 24 - Bounding Analysis Curve – ADS Stage 4 – 14" (610 °F)

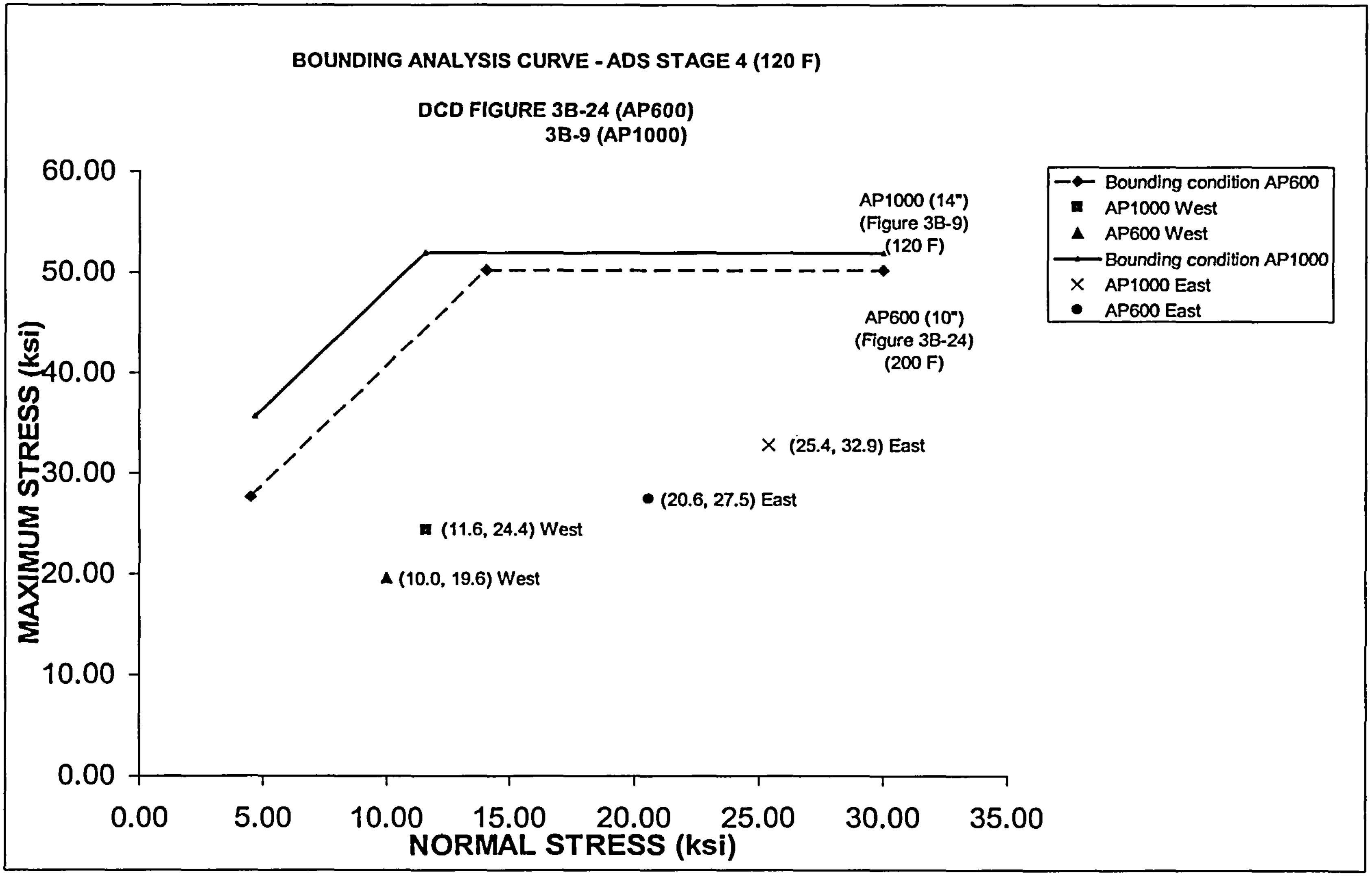


Figure 25 - Bounding Analysis Curve – ADS Stage 4 – 14" (120 °F)

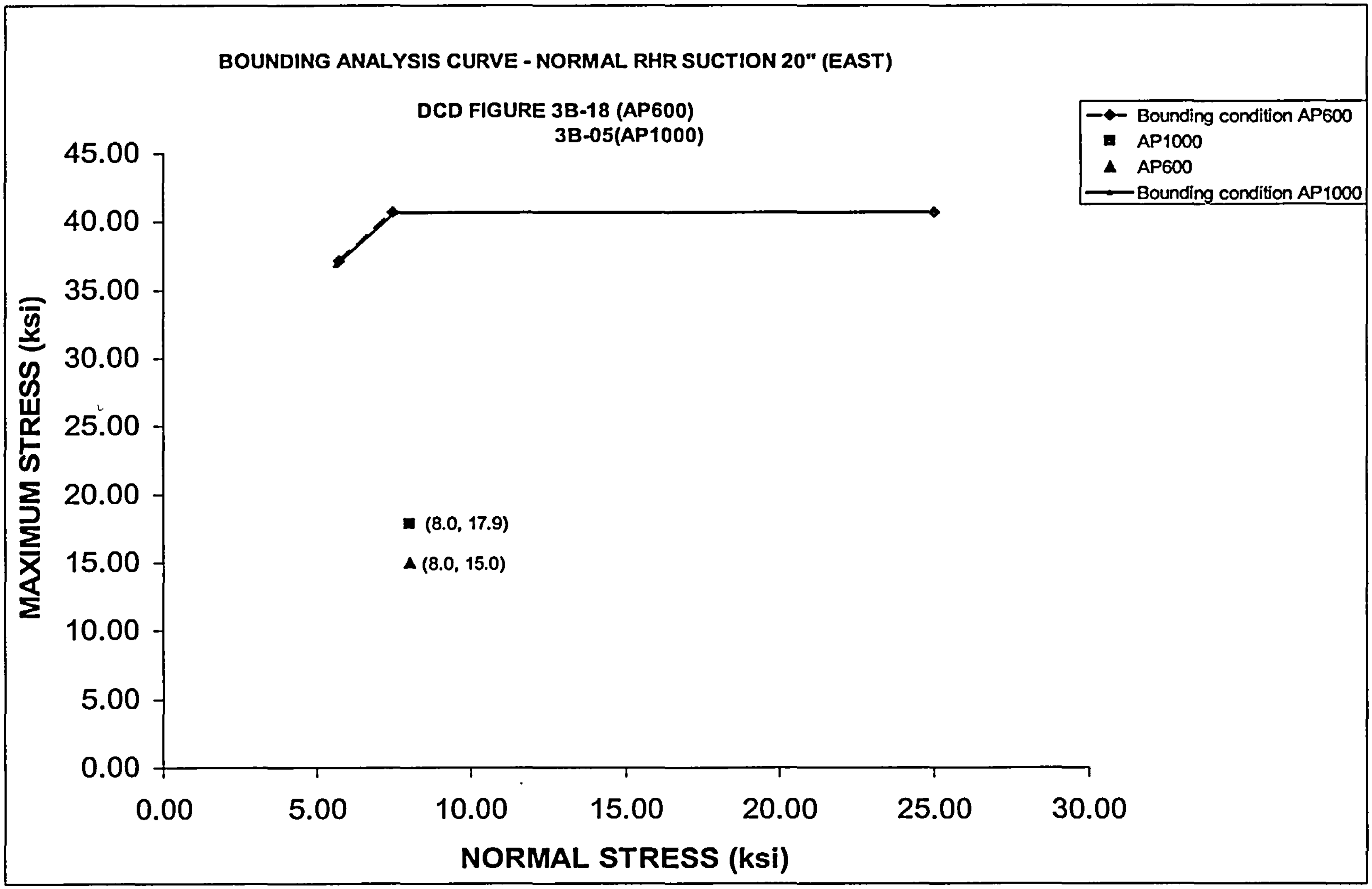


Figure 26 - Bounding Analysis Curve – Normal RHR Suction – 20”

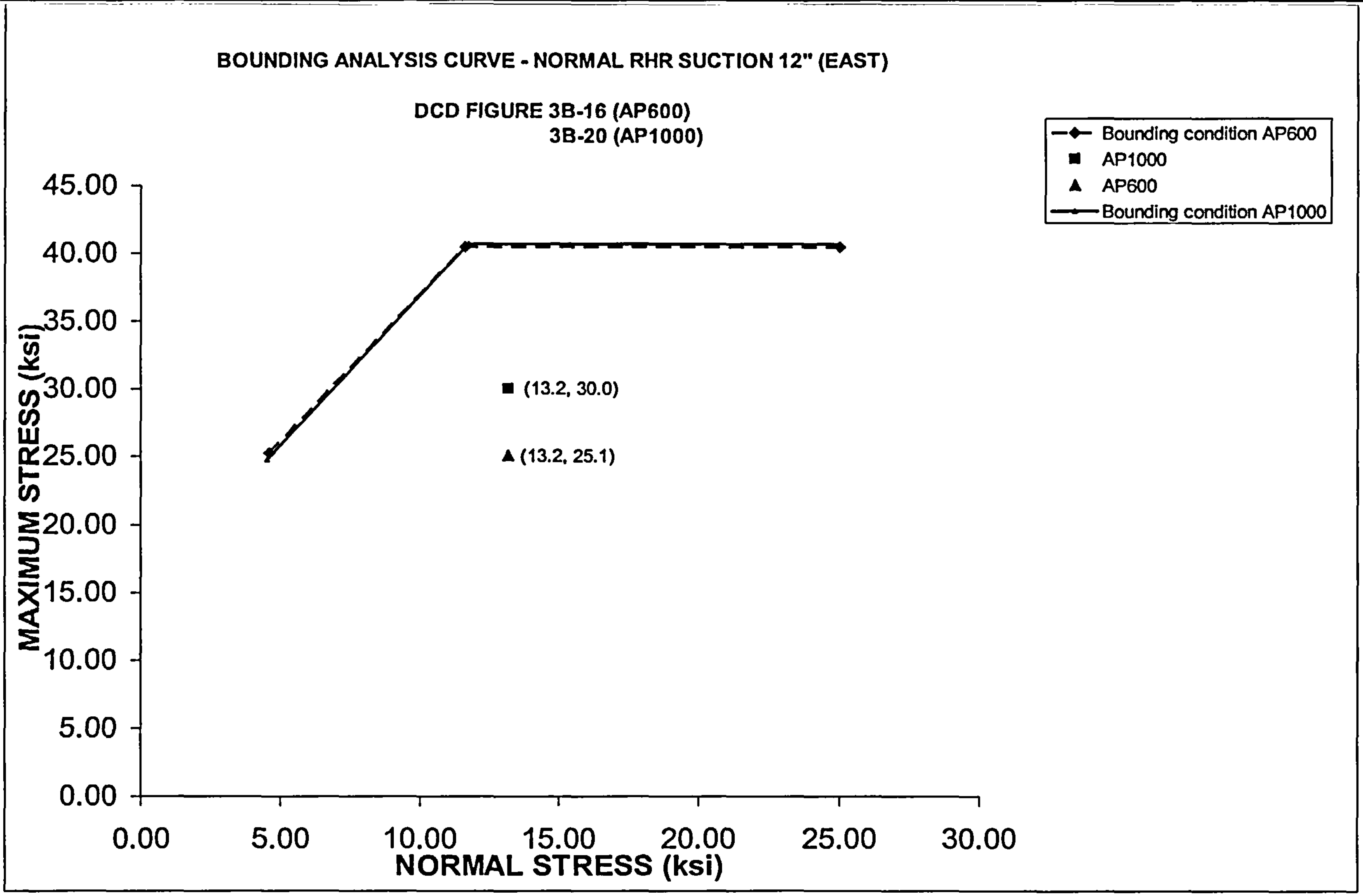


Figure 27 - Bounding Analysis Curve – Normal RHR Suction – 12"

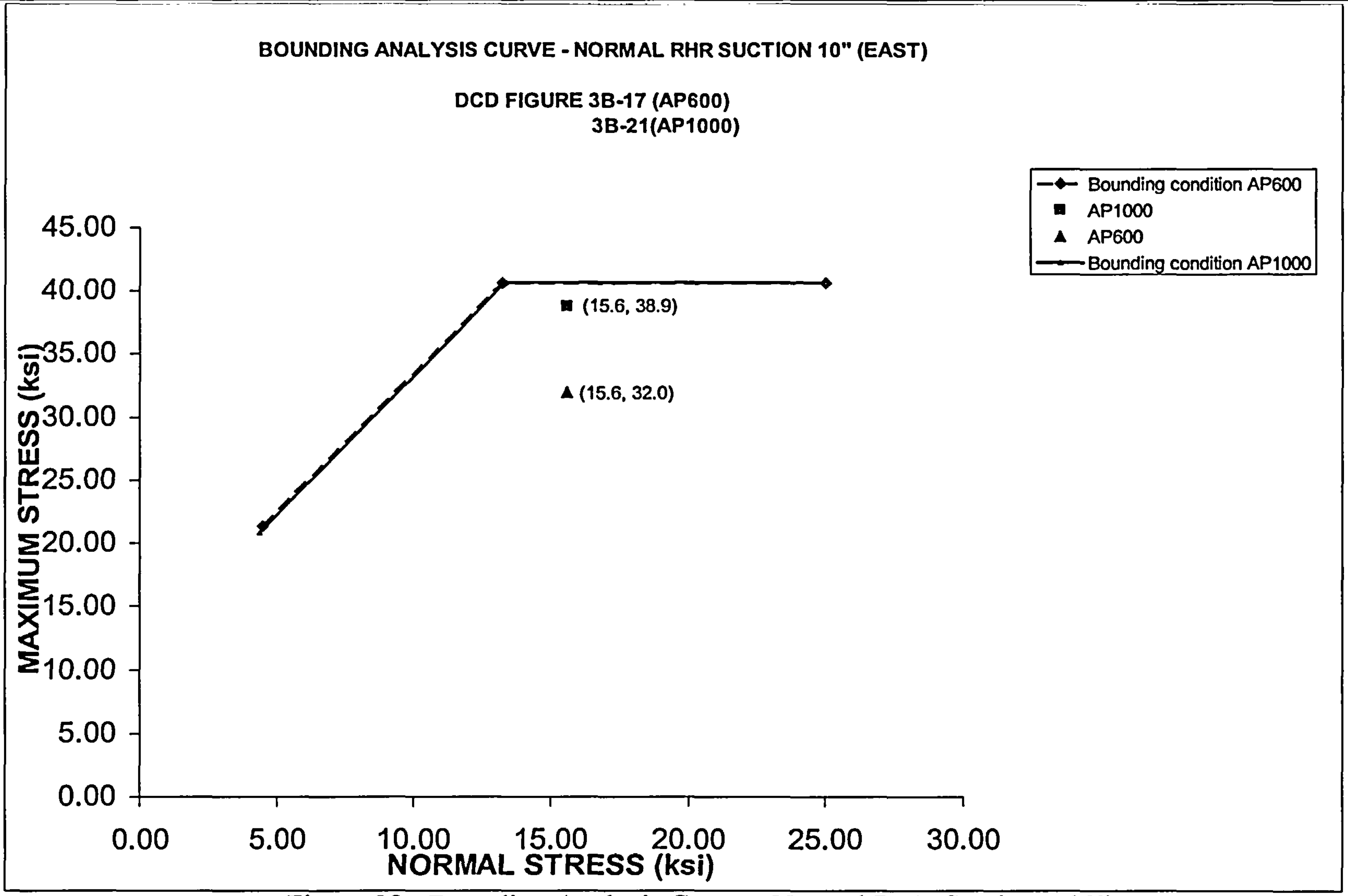


Figure 28 - Bounding Analysis Curve – Normal RHR Suction – 10"

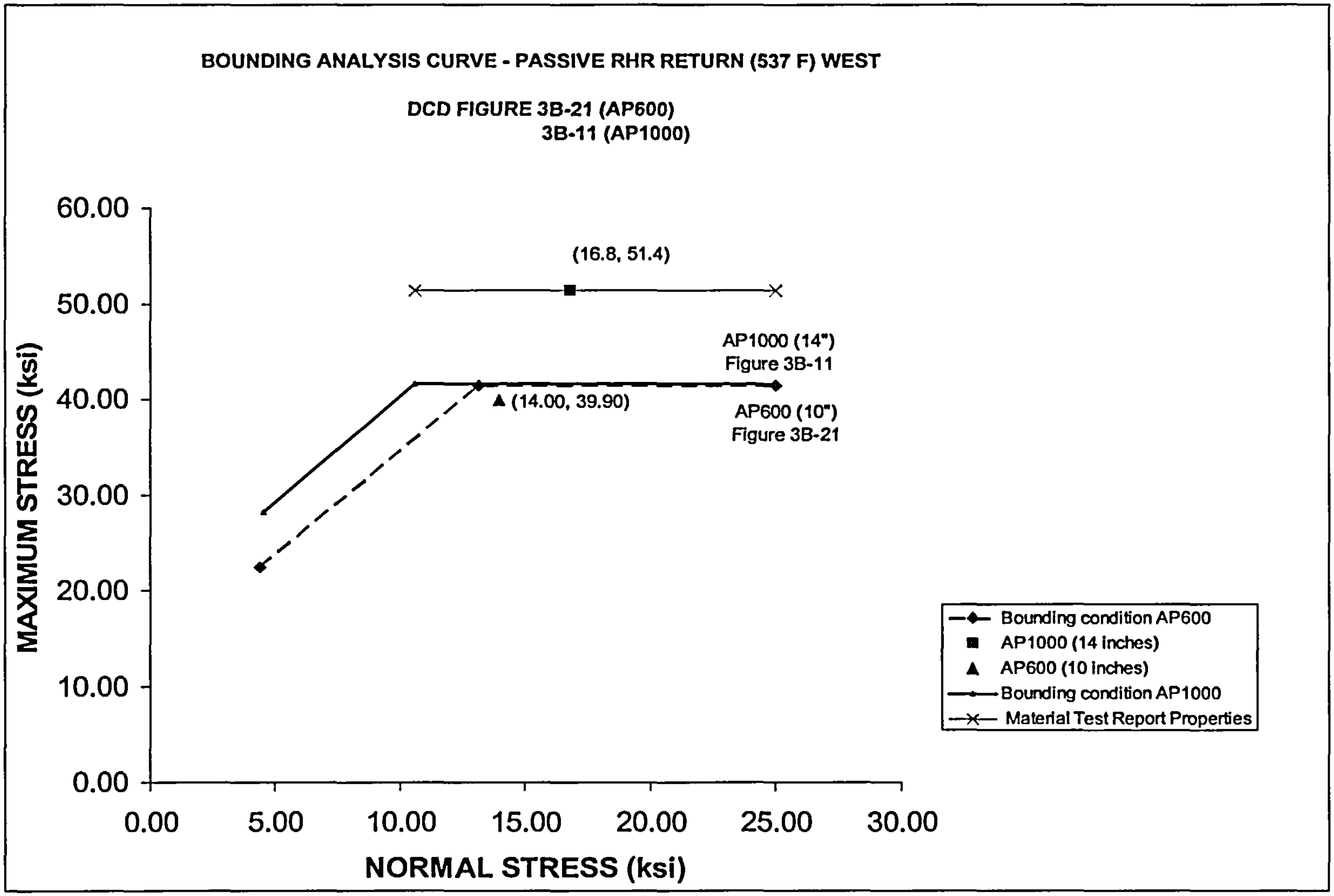


Figure 29 - Bounding Analysis Curve – Passive RHR Return – 14"

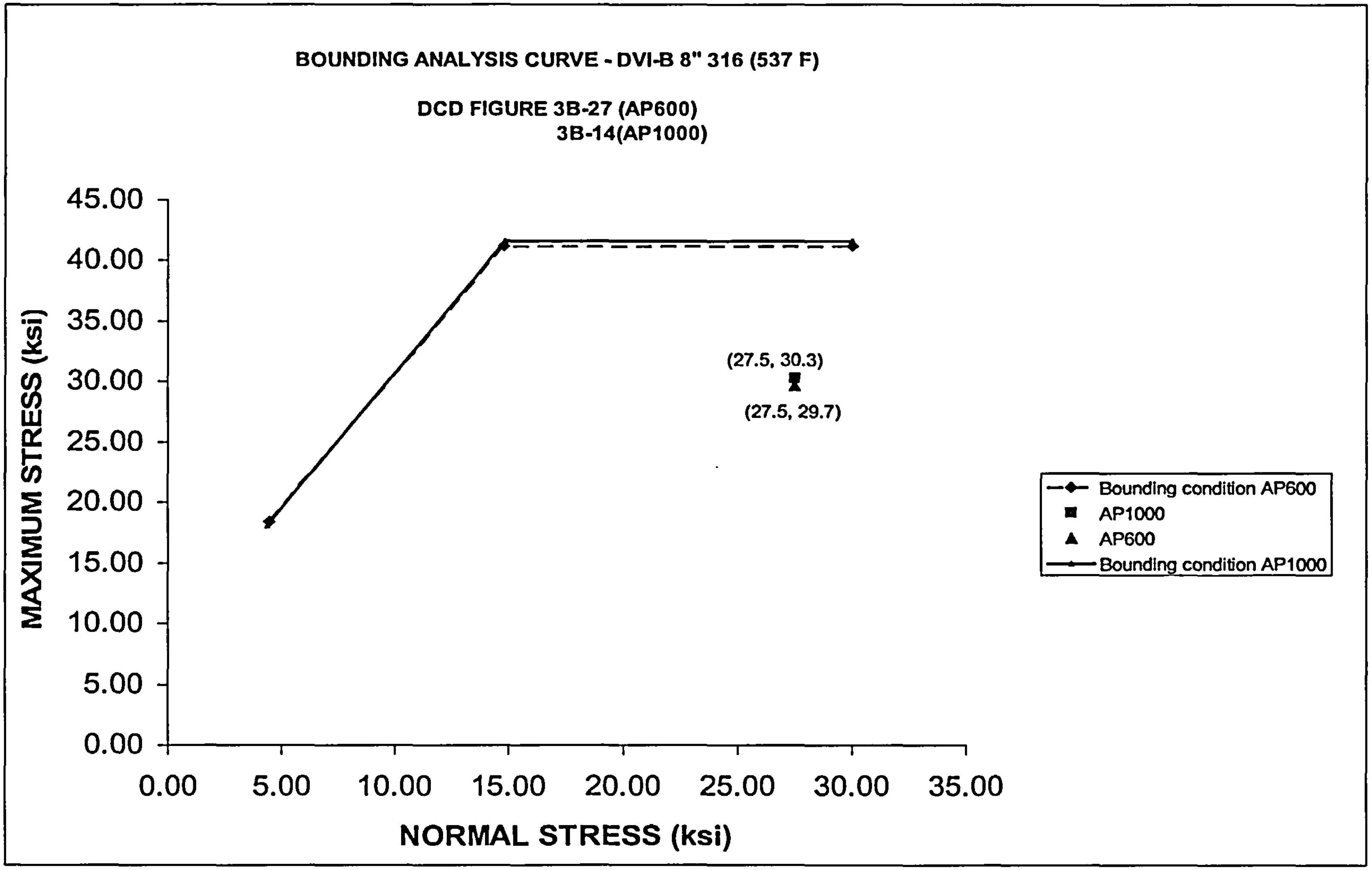


Figure 30 - Bounding Analysis Curve – DVI-B – 8" (316 SS, 537 °F)

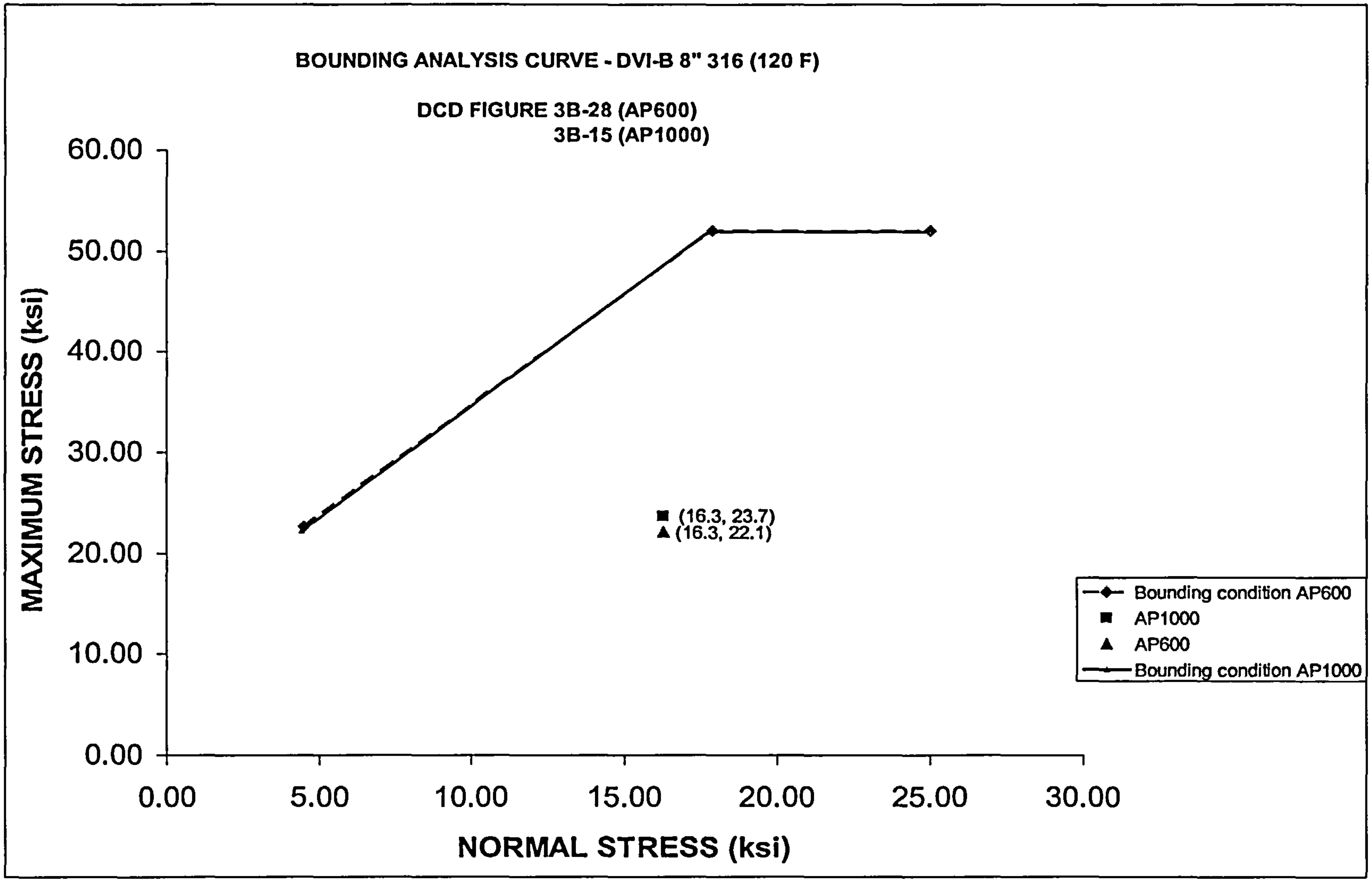


Figure 31 - Bounding Analysis Curve – DVI-B – 8" (316 SS, 120 °F)

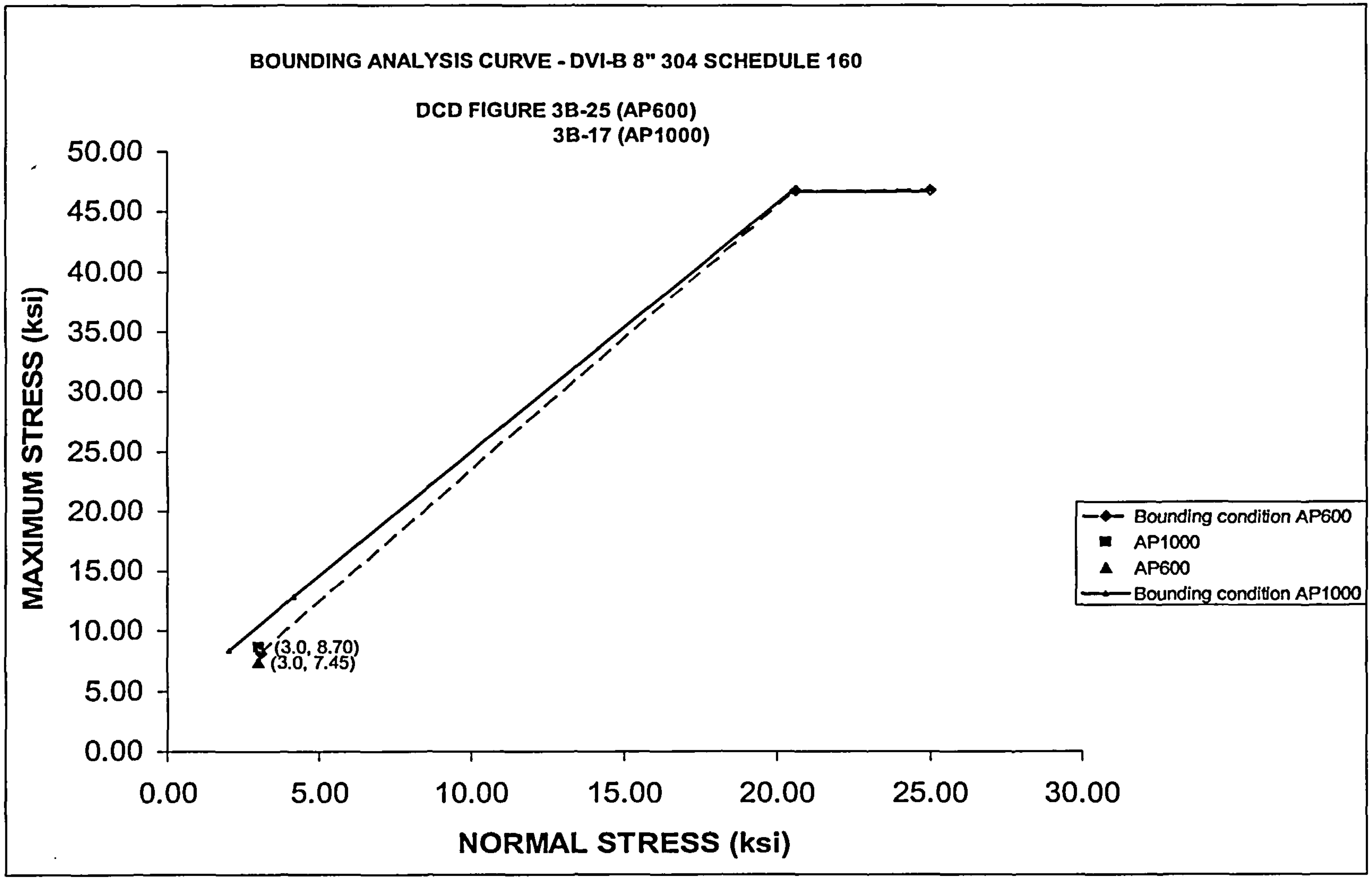


Figure 32 - Bounding Analysis Curve – DVI-B – 8" (304 SS)

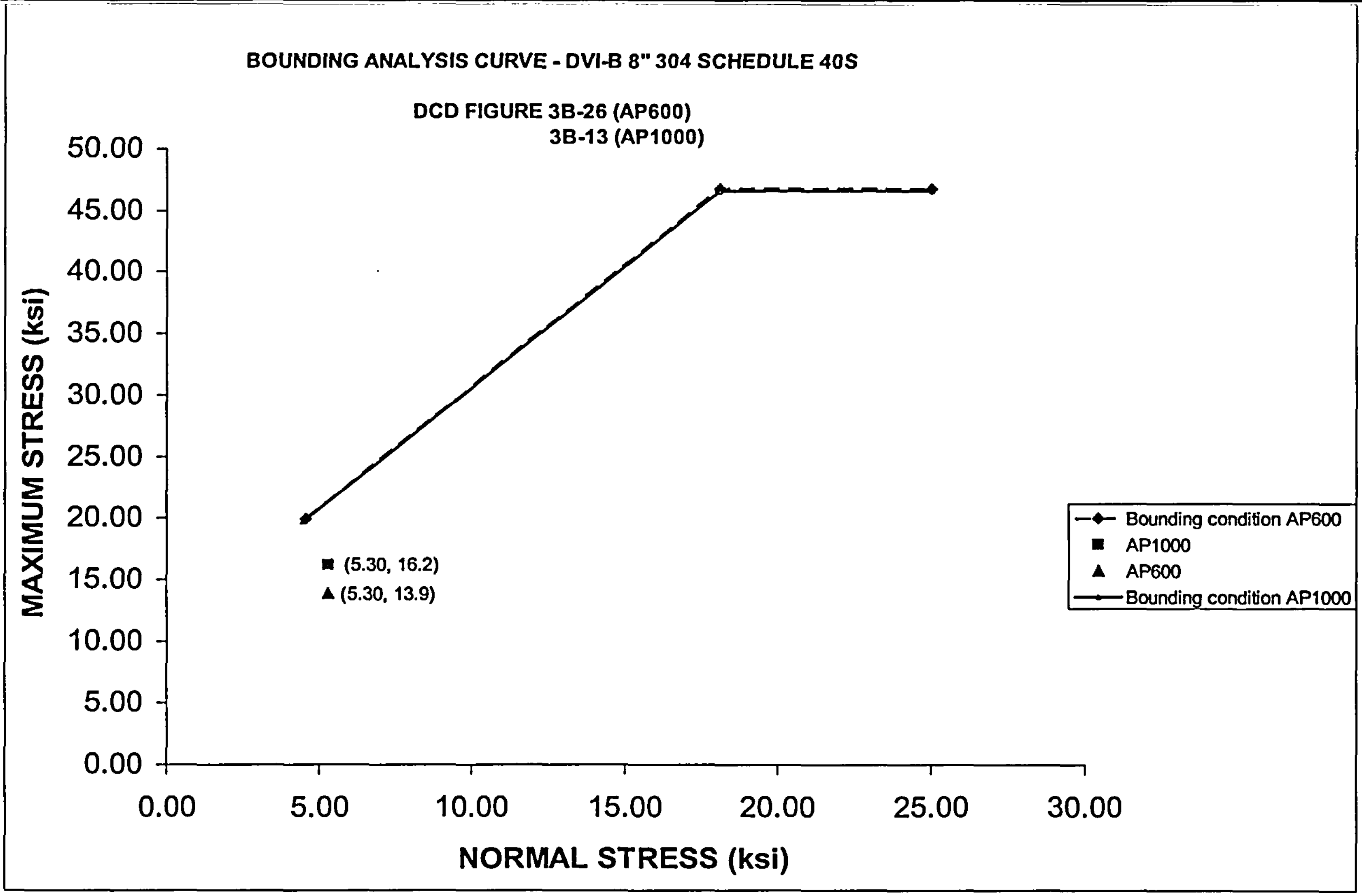


Figure 33 - Bounding Analysis Curve – DVI-B – 8" (Sch 40S)

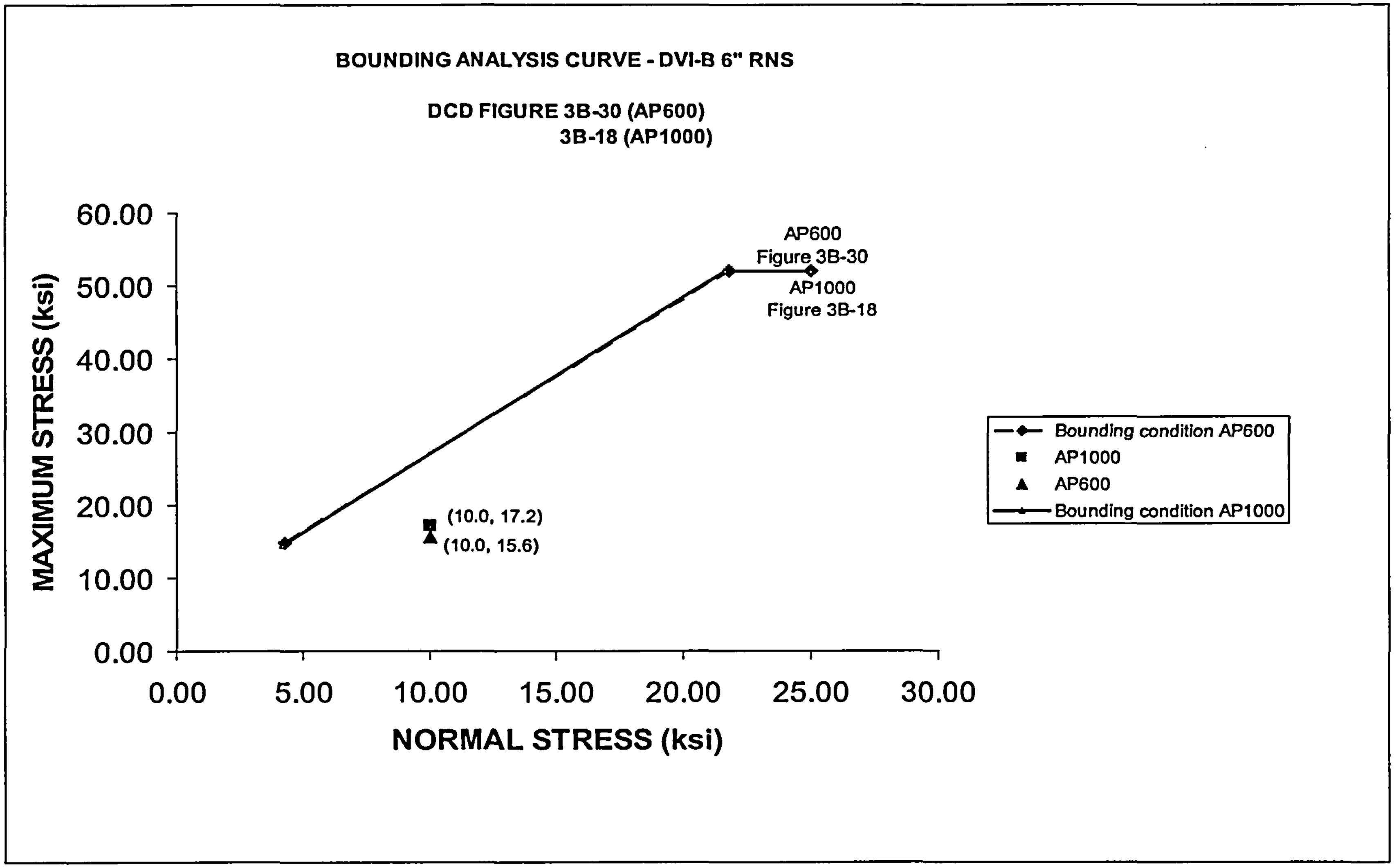


Figure 34 - Bounding Analysis Curve – DVI-B – 6" RNS

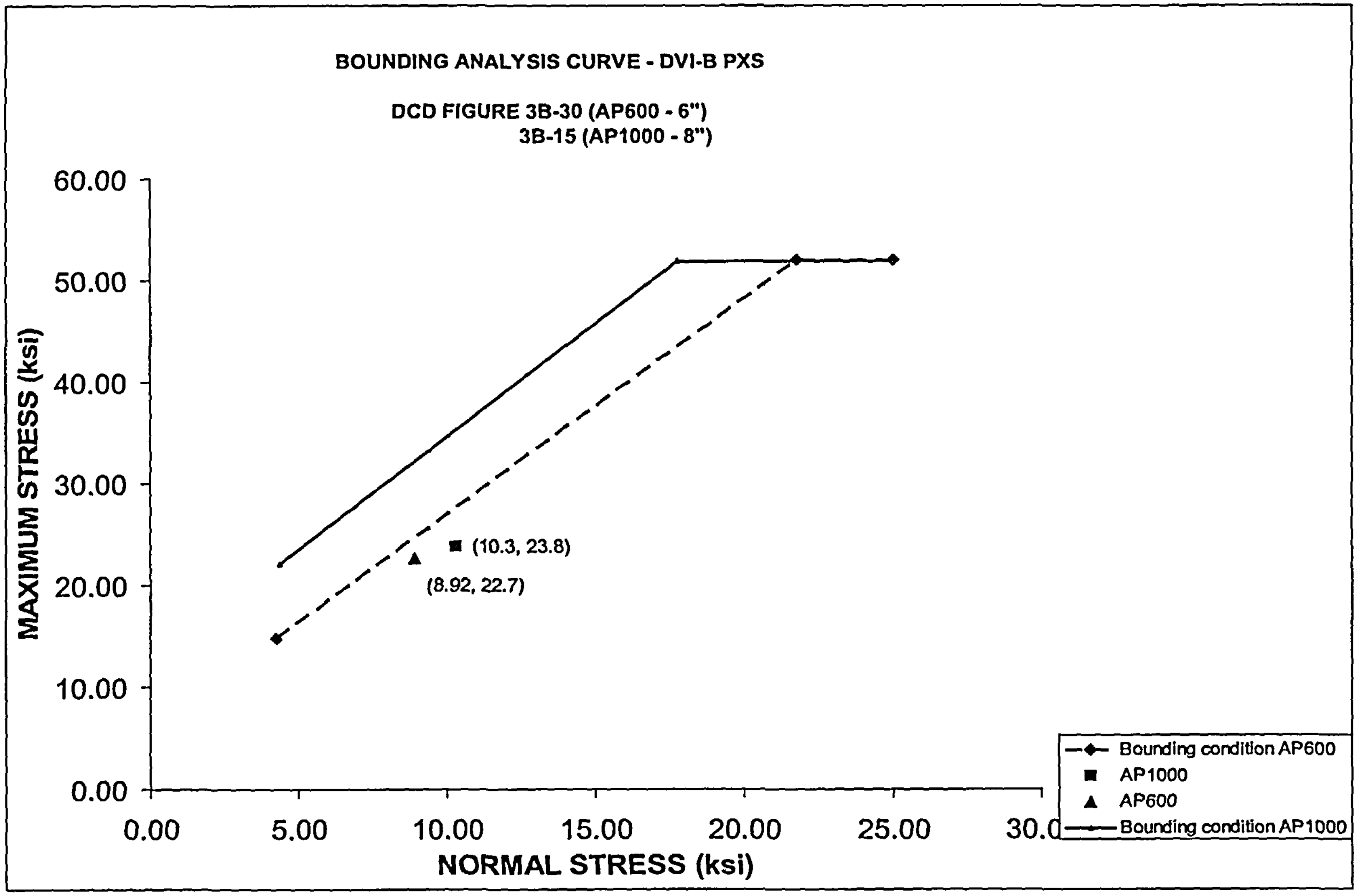


Figure 35 - Bounding Analysis Curve – DVI-B – 8" PXS

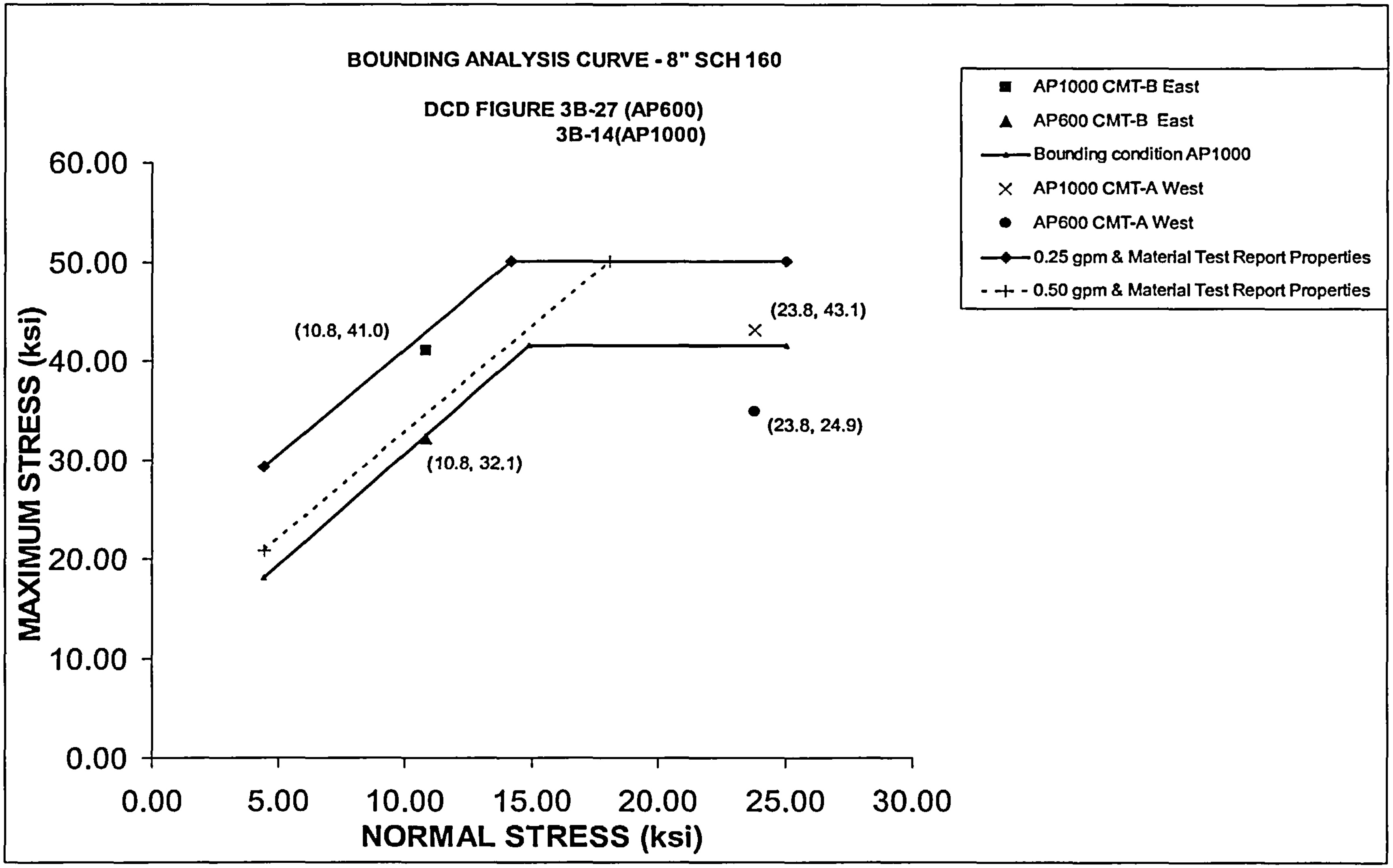


Figure 36 - Bounding Analysis Curve – CMT - 8”

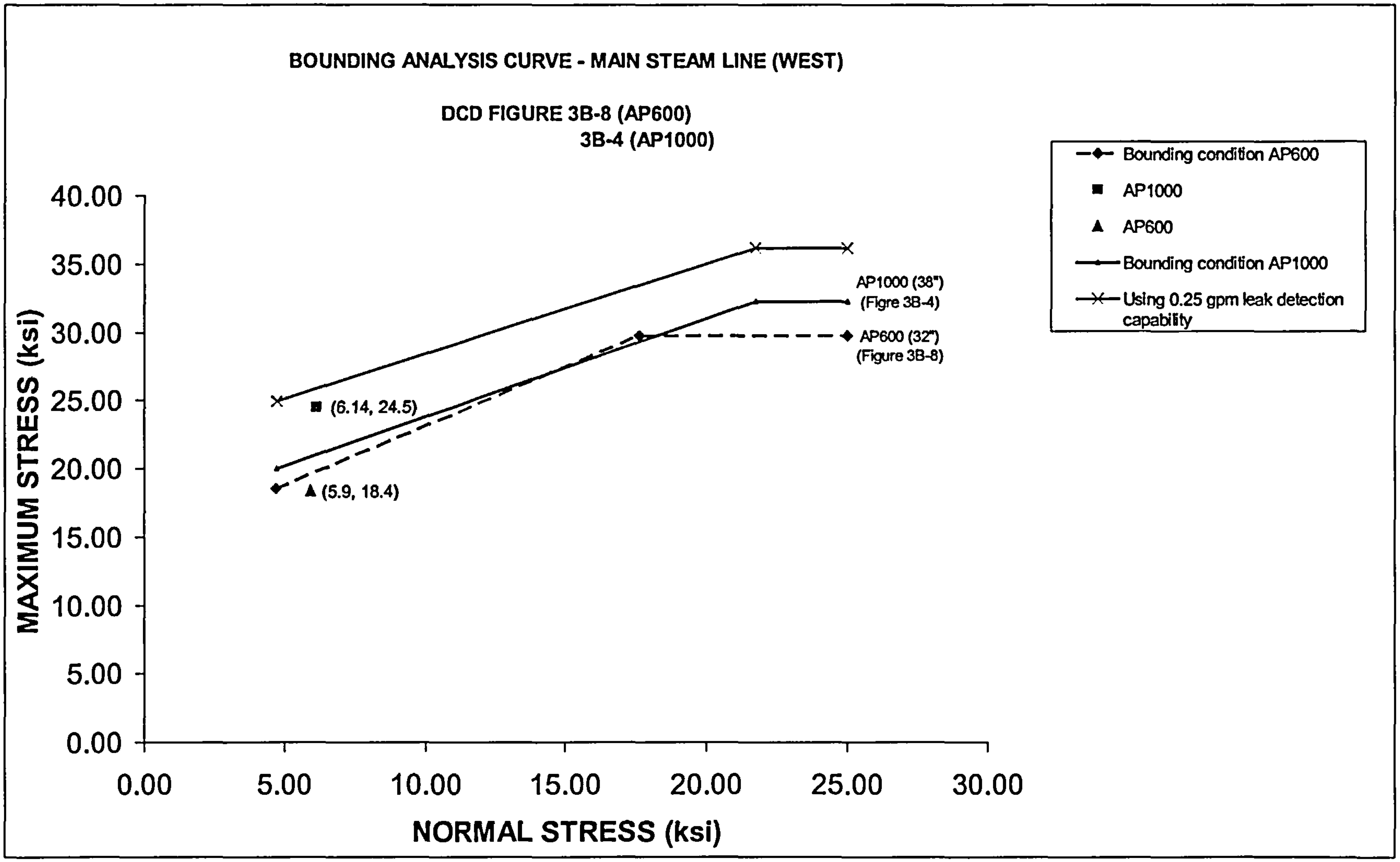


Figure 37 - Bounding Analysis Curve – Main Steam – West – 38"

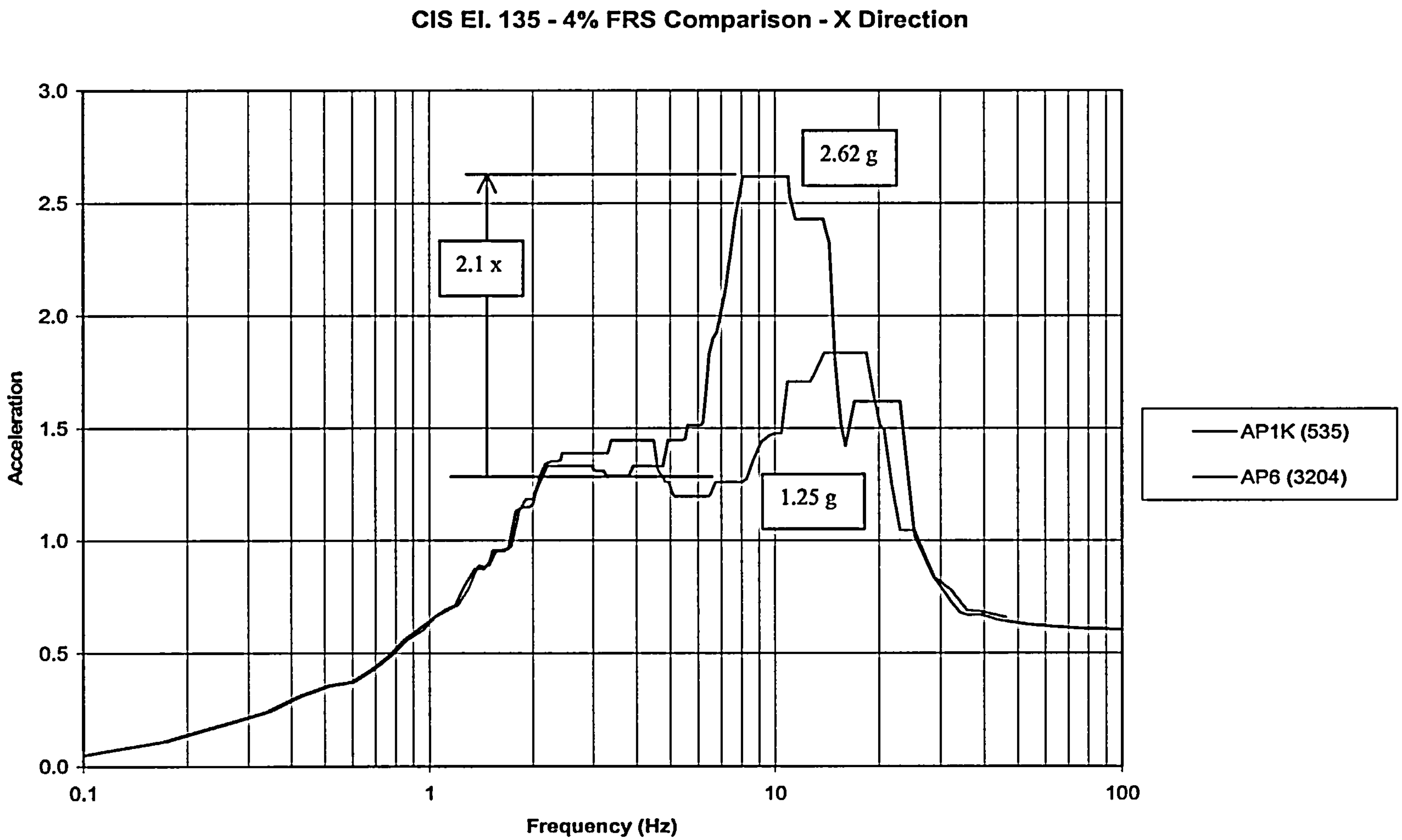


Figure 38 : Bounding Seismic Increase Factors -
Seismic Response Spectra, Steam Generator Support Elev. 135', (North-South) – 4th Stage ADS

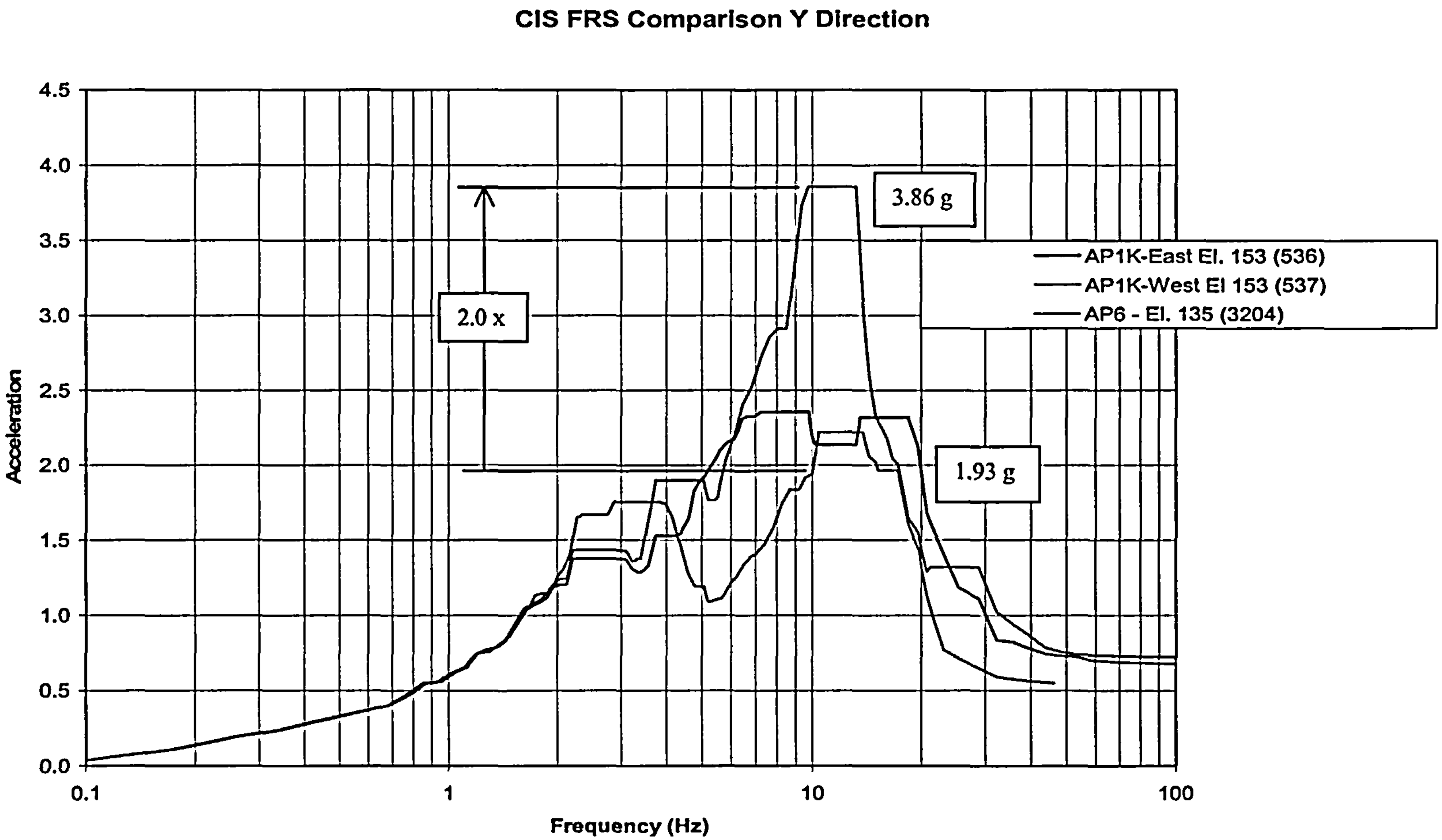


Figure 39 : Bounding Seismic Increase Factors
Seismic Response Spectra, Steam Generator Support Elev. 153' (East-West) – 4th Stage ADS

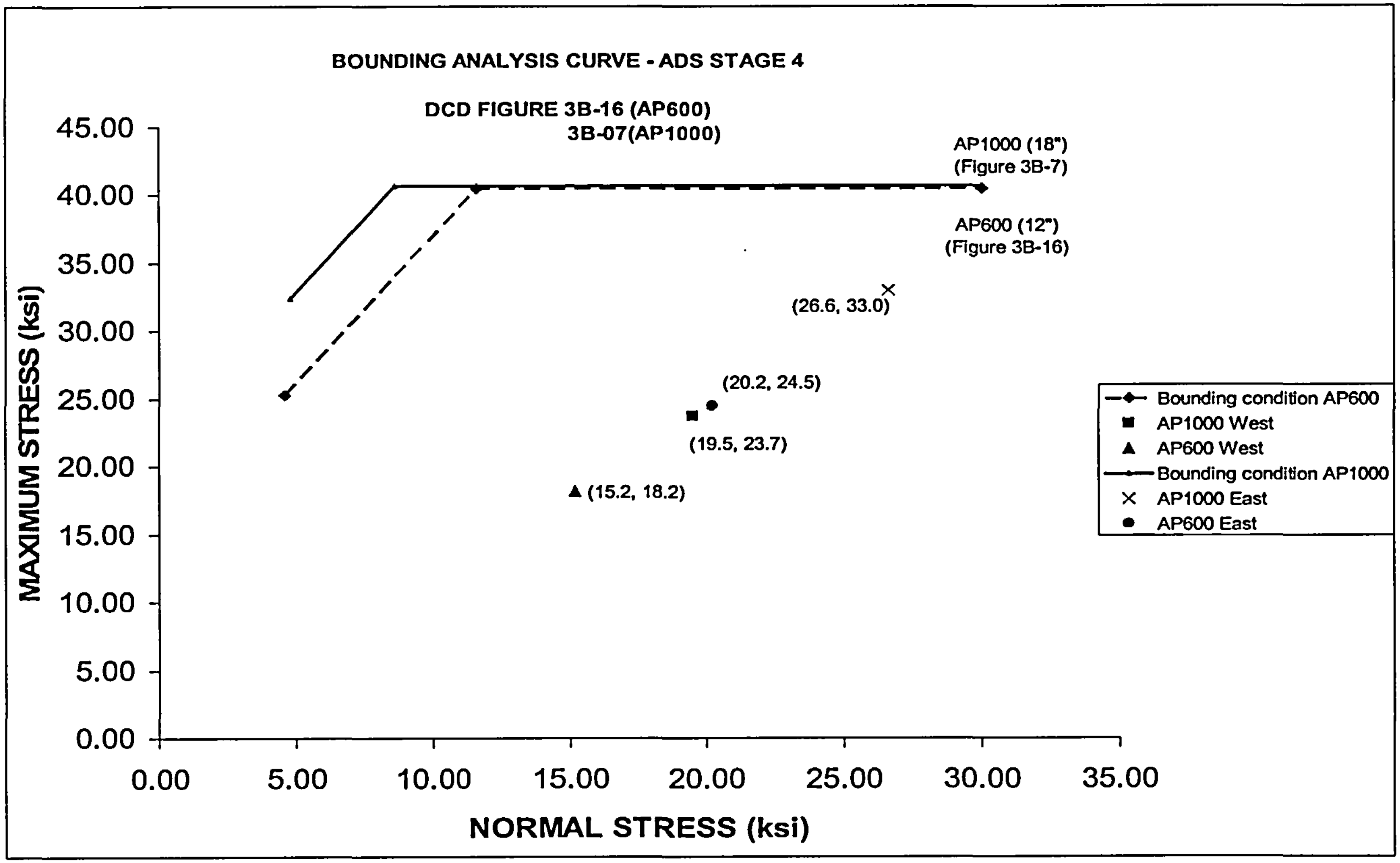


Figure 40 - Bounding Analysis Curve – ADS Stage 4 – 18" – Bounding Seismic Increase Factor

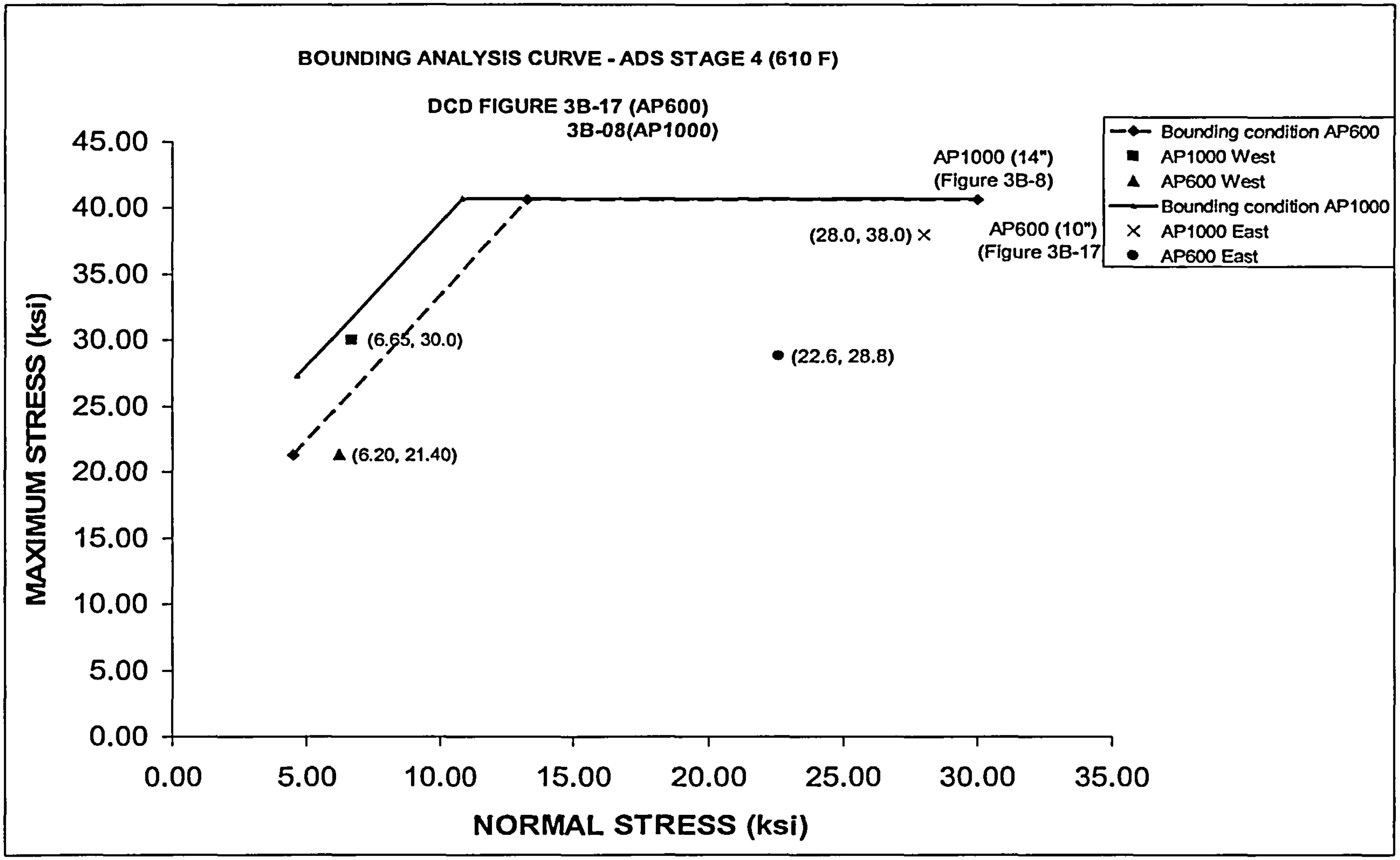


Figure 41 - Bounding Analysis Curve – ADS Stage 4 – 14" (610°F) – Bounding Seismic Increase Factor

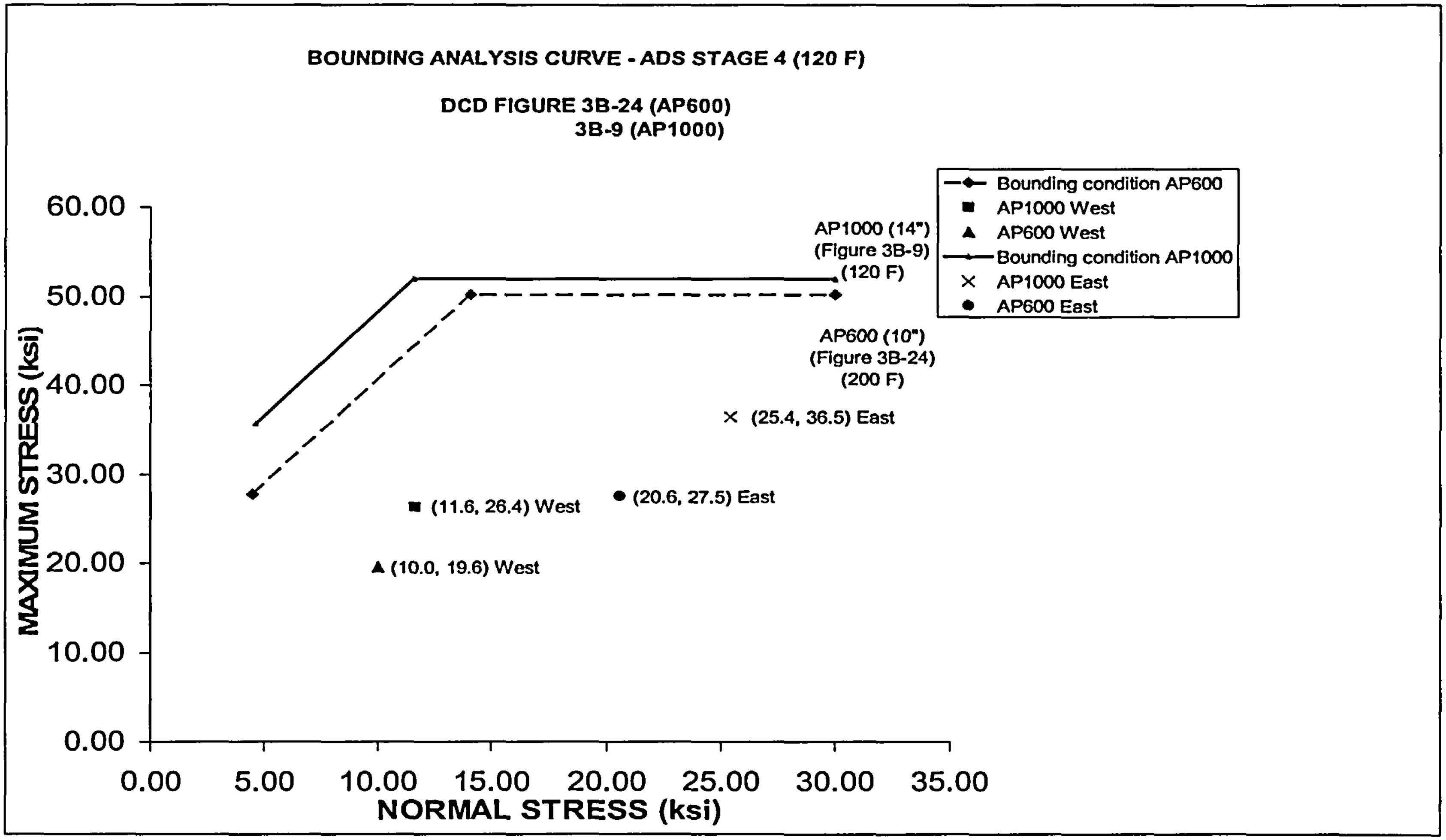


Figure 42 - Bounding Analysis Curve – ADS Stage 4 – 14" (120°F) – Bounding Seismic Increase Factor

APPENDIX A

Summary of Sample Certified Material Test Reports Review			
	Room temperature CMTRs properties		
Plant	Material	Yield Strength (psi)	Ultimate Strength (psi)
Plant A	A376/TP316	46800	93800
Aux. lines	A376/TP316	48000	86400
	A376/TP316	45600	87900
	A376/TP316	41300	83200
	A376/TP316	38600	82600
	A376/TP316	44900	84000
Plant B	A376/TP316	59100	84900
Aux. lines	A376/TP316	52100	87400
	A376/TP316	51900	85400
	A376/TP316	48400	84900
	A376/TP316	59100	84900
	A376/TP316	47400	81100
	A376/TP316	47400	81100
	A376/TP316	59100	84900
	A376/TP316	48400	84900
	A376/TP316	48400	84900
	A376/TP316	59100	84900
	A376/TP316	45200	87600
	A376/TP316	51900	85400
	A376/TP316	59100	84900
	A376/TP316	59100	84900
	A376/TP316	59100	84900
	A376/TP316	45200	87600
	A376/TP316	48400	84900
	A376/TP316	47400	81100
	A376/TP316	45200	87600
	A376/TP316	51900	85400
	A376/TP316	47400	81100
	A376/TP316	47400	81100
	A376/TP316	47400	81100
	A376/TP316	59100	84900
	A376/TP316	59100	84900
	A376/TP316	51900	85400
	A376/TP316	52100	87400

Summary of Sample Certified Material Test Reports Review			
	Room temperature CMTRs properties		
Plant	Material	Yield Strength (psi)	Ultimate Strength (psi)
	A376/TP316	47400	81100
	A376/TP316	59100	84900
	A376/TP316	47400	81100
	A376/TP316	51900	85400
	A376/TP316	59100	84900
	A376/TP316	59100	84900
	A376/TP316	48400	84900
	A376/TP316	52100	87400
	A376/TP316	59100	84900
	A376/TP316	47400	81100
	A376/TP316	39200	84200
	A376/TP316	42200	84900
	A376/TP316	39200	84200
	A376/TP316	52100	87400
	A376/TP316	52100	87400
	A376/TP316	52100	87400
	A376/TP316	45200	87600
	A376/TP316	52100	87400
	A376/TP316	51900	85400
	A376/TP316	48400	84900
Plant C	A376/TP316	43300	85600
Aux. lines	A376/TP316	42700	88200
	A376/TP316	38100	82600
	A376/TP316	43300	85600
	A376/TP316	42700	88200
	A376/TP316	38100	82600
	A376/TP316	40100	83000
	A376/TP316	38100	82600
	A376/TP316	43300	87800
	A376/TP316	44100	88600
	A376/TP316	40100	83000
	A376/TP316	40500	84600
	A376/TP316	44500	81400
	A376/TP316	50250	87400
	A376/TP316	42400	84900
	A376/TP316	42100	89000
	A376/TP316	39700	86200
	A376/TP316	44500	81400

Summary of Sample Certified Material Test Reports Review			
	Room temperature CMTRs properties		
Plant	Material	Yield Strength (psi)	Ultimate Strength (psi)
	A376/TP316	44500	81400
Plant D	A376/TP316	42700	88200
Aux. lines	A376/TP316	38100	82600
	A376/TP316	42700	88200
	A376/TP316	38100	82600
	A376/TP316	42700	88200
	A376/TP316	46700	92600
	A376/TP316	42700	88200
	A376/TP316	42050	82500
	A376/TP316	44600	85100
	A376/TP316	49100	81200
	A376/TP316	41150	80900
	A376/TP316	49100	81200
	A376/TP316	41150	80900
	A376/TP316	42100	82900
	A376/TP316	51400	91050
	A376/TP316	42050	82500
	A376/TP316	41150	80900
	A376/TP316	49100	81200
	A376/TP316	40100	83000
	A376/TP316	40100	83000
	A376/TP316	40100	83000
	A376/TP316	41100	98400
	A376/TP316	39300	84200
	A376/TP316	41150	80900
	A376/TP316	45150	86600
	A376/TP316	41050	79600
	A376/TP316	41150	80900
	A376/TP316	41050	79600
	A376/TP316	41650	78550
	A376/TP316	41050	79600
Plant E	A376/TP316	38800	84500
Aux. lines	A376/TP316	45600	87900
	A376/TP316	41300	83200
	A376/TP316	41900	87400
Plant F	A376/TP316	41400	87100

Summary of Sample Certified Material Test Reports Review			
	Room temperature CMTRs properties		
Plant	Material	Yield Strength (psi)	Ultimate Strength (psi)
Aux. lines	A376/TP316	42400	86100
	A376/TP316	40900	86100
	A376/TP316	38900	79400
	A376/TP316	39300	82600
	A376/TP316	42500	83800
	A376/TP316	42200	86100
	A376/TP316	42200	86100
	A376/TP316	44900	84200
	A376/TP316	41200	81600
	A376/TP316	41700	85800
	A376/TP316	42900	84600
	A376/TP316	39700	83400
	A376/TP316	40200	85100
	A376/TP316	40200	83000
	A376/TP316	40900	82600
	A376/TP316	40200	84200
	A376/TP316	44500	86300
	A376/TP316	44600	84800
	A376/TP316	44200	85000
Plant G	A376/TP316	38200	82900
Aux. lines	A376/TP316	38200	82900
	A376/TP316	38200	82900
	A376/TP316	38200	82900
Plant H	A376/TP316	47100	88500
Aux. lines	A376/TP316	47100	88500
	A376/TP316	47100	88500
	A376/TP316	48600	88500
	A376/TP316	47100	88500
	A376/TP316	38400	79900
	A376/TP316	49300	83100
Plant I	A376/TP316	42700	88200
Aux. lines	A376/TP316	42700	88200
	A376/TP316	42700	88200
	A376/TP316	42700	88700
	A376/TP316	43300	85600
	A376/TP316	43300	85600

Summary of Sample Certified Material Test Reports Review			
	Room temperature CMTRs properties		
Plant	Material	Yield Strength (psi)	Ultimate Strength (psi)
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	43900	89800
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	43900	89800
	A376/TP316	44500	81400
	A376/TP316	38100	82600
	A376/TP316	43900	89800
	A376/TP316	44100	88600
	A376/TP316	43300	87800
	A376/TP316	43900	89800
	A376/TP316	43300	87800
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	40500	84600
	A376/TP316	43800	89800
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	44500	81400
	A376/TP316	44500	81400
Total 169 Heats	Average	45228.70	84704.73
Average Flow stress=	(45228.70+84704.73)/2=	64967 psi	
ASME Code Flow stress=	(30000+75000)/2=	52500 psi	
Ratio of flow stresses=	64967/52500=	1.237	

AP1000 DESIGN CERTIFICATION REVIEW

Draft Safety Evaluation Report Open Item Response

DSER Open Item Number: 5.3.3-1 (Revision 2 Response)

Original RAI Number(s): 251.018

Summary of Issue:

The staff requested, in RAI 251.018, that the applicant demonstrate that the P-T limits are in accordance with Appendix G to 10 CFR Part 50. The applicant responded, that the AP1000 heatup and cooldown operating curves were generated using the most limiting adjusted reference temperature values and the NRC-approved methodology as documented in WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," with staff approved exceptions.

One exception is that instead of using best estimate fluence values, the applicant is using fluence values that are calculated fluence values. The staff finds this acceptable because this is in compliance with RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." The other exception is that the KIc critical stress intensities are used in place of the KIa critical stress intensities. This methodology is taken from staff approved ASME Code Case N-641. The staff found the applicant's responses acceptable because the AP1000 P-T limit curves were developed in accordance with 10 CFR Part 50, Appendix G, with the exception that the flange requirement is in accordance with WCAP 15315, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Operating PWR and BWR Plants." Currently, the staff has not approved WCAP 15315. Any changes to the RV closure head requirements would be incorporated into Appendix G of 10 CFR Part 50. If a relaxation to 10 CFR Part 50, Appendix G is approved, this will allow the operating window to be wider. Since applicants using AP1000 are required to meet the requirements of 10 CFR Part 50, Appendix G, applicants using AP1000 must meet the closure head requirements of Appendix G of 10 CFR Part 50. However, the AP1000 DCD does not provide limitations (values of RTNDT) for the closure flange region of the RV and head. The AP1000 design must include these limitations in order to satisfy Appendix G of 10 CFR Part 50. The applicant should provide these limitations that are consistent with the present TSs and 10 CFR Part 50, Appendix G, or provide closure flange limitations with new TSs that are consistent with 10 CFR Part 50, Appendix G. This is Open Item 5.3.3-1.

Westinghouse Response (Revision 1):

~~Since it is recognized that the elimination of the flange requirement, as discussed in WCAP 15315, results in plant safety and operational improvements, Westinghouse proposes to maintain the P/T curves without the flange requirement in the AP1000 DCD and request exemption from the 10 CFR Part 50 Appendix G flange limits. Westinghouse requests further interaction with the NRC staff to resolve any technical issues associated with this exemption.~~

~~When evaluating the request for exemption, consideration should be given to the COL item in DCD Section 5.3.6.1 in which it is recognized that the P/T curves given in the DCD are generic~~

~~curves and that the Combined License Applicant is committed to addressing P/T curves based on the as-procured reactor vessel material. An LTOPS evaluation, including assessment of the RHR relief valve setpoint and relief capacity, is also committed to be performed to determine the impact of any changes in the P/T curves.~~
Westinghouse will revise the AP1000 DCD to include P/T curves that meet the reactor vessel closure head flange requirements of 10 CFR Part 50 Appendix G. The normal RHR system relief valve setpoint and capacity will also be revised as a result of a revised LTOPS evaluation based on the new P/T curves.

The impact of the revised normal RHR system relief valve setpoint and capacity on the analyses of a loss of normal RHR cooling in Mode 4 with the RCS intact (DCD Section 19E.4.8.2) is being evaluated.

A review of the ITAAC associated with the normal RHR system relief valve (Tier 1 Section 2.3.6) shows that specification of the relief valve capacity based on the generic P/T curves in the DCD is inconsistent with the COL item in Section 5.3.6.1. The COL item requires an evaluation of the adequacy of the normal RHR system relief valve based on the P/T curves developed for the as-procured reactor vessel material, which could result in a revised required relief valve capacity. The ITAAC associated with the normal RHR system relief valve will be revised to a more general requirement so that this ITAAC is compatible with the possibility of changes in the required capacity of the valve as a result of P/T curves based on as-procured reactor vessel material.

NRC Follow-On Comments:

The following NRC comments are from the Westinghouse/NRC meeting of October 30, 2003:

1) Items 9ai and 9aii in the RNS System ITAAC Table 2.3.6-4 seem to be redundant.
2) There is a later version of the referenced methodology for development of the RCS pressure/temperature curves.
3) Provide a response to the information requested in RAI 440.036 for the revised LTOPS analysis. RAI 440.036 requested the following:

   Section 5.2.2.1 states that a relief valve in the residual heat removal system (RNS) provides low-temperature overpressure protection (LTOP) for the RCS, and that the valve is sized to prevent overpressure based on the following design basis events with a water solid pressurizer:

   (1) the limiting mass input event of the makeup/letdown flow mismatch, and
   (2) the limiting heat input event of inadvertent start of a reactor coolant pump (RCP).

   Provide the safety analyses of both the limiting mass-input and heat-input overpressure events to support the adequacy of the RNS relief valve relieving capacity and set pressure specified in Table 5.4-17 for the LTOP. The description should include:

A. The applicable RCS pressure-temperature limits (LCO 3.4.3) with corresponding neutron fluence values of the reactor vessel, or the effective full power years.

B. The analysis methodology and assumptions, including consideration of limiting single failure assumption, the instrumentation uncertainties of pressure and temperature measurements, the relief valve set pressure and accumulation, the dynamic head effect of the reactor coolant flow, and the static head between the pressure tap and the limiting vessel locations, and pressure overshoot.

C. The analysis results.

D. The determination of the LTOP enable temperature of 275°F (Technical Specifications LCO 3.4.15).

Westinghouse Response to NRC Follow-On Comments (Open Item Revision 2 Response):

1) ITAAC Table 2.3.6-4

Westinghouse will revise the acceptance criteria for Item 9aii in Table 2.3.6-4, as shown below in the DCD Revisions From Revision 2 Response.

2) Pressure/Temperature (P/T) Curve Development Methodology

The 1996 version (Revision 2) of WCAP-14040 is referenced as the methodology used in the development of the AP1000 pressure/temperature curves. This revision has been approved by the NRC. There is currently a Revision 3 of this document, and it is expected that the next NRC approved revision will be Revision 4.

As stated in DCD subsection 5.3.3.1, the AP1000 P/T curves were developed using the methodology of WCAP-14040 (Revision 2) with the following exceptions:

- The fluence values used are calculated fluence values (i.e., comply with Regulatory Guide 1.190), not the best-estimate fluence values.
- The K_{Ic} critical stress intensities are used in place of the K_{Ia} critical stress intensities. This methodology is taken from approved ASME Code Case N-641 (which covers Code Cases N-640 and N-588).
- The 1996 Version of Appendix G to Section XI is used rather than the 1989 version.

Revision 4 of WCAP-14040 will incorporate all three of these exceptions into the P/T curve methodology. Therefore, the P/T curves will be the same whether developed according to WCAP-14040 Revision 2 with the above exceptions or according to Revision 4. Since Revision 4 is not yet approved by the NRC, the appropriate documentation of the P/T curve methodology is that which is currently in subsection 5.3.3.1 of DCD Revision 7.

3) Revised LTOPS Analysis

The normal residual heat removal system (RNS) relief valve mitigates the low temperature overpressure transients and is sized to prevent the RCS pressure from exceeding the lower of either the applicable pressure-temperature (P/T) limit or 110% of the RNS system design pressure. The limiting mass and energy input transients assumed for the sizing analysis are as follows:

- Mass Input: Injection of water into the RCS from the operation of both makeup pumps due to makeup/letdown flow mismatch. The maximum flow mismatch is 177 gpm. The makeup flow is limited by the cavitating venturi located in the discharge header of the chemical and volume control system makeup pumps.

- Energy Input: During an RCS cooldown, the reactor coolant pumps are tripped at an RCS temperature of approximately 160 F. Below this temperature, the RNS continues to cool down the RCS, while the steam generators may remain at or near 160 F. It can be postulated that a 50 F differential temperature can be developed between the RCS and the steam generators under this condition. Subsequent restart of one reactor coolant pump under these conditions results in the limiting energy input cold overpressure transient. This transient is postulated to occur over a range of reactor coolant temperatures between 70 F and 200 F because an administrative requirement has been imposed in the Technical Specifications that does not allow a reactor coolant pump to be started while the RCS is water solid and the RCS temperature is above 200 F.

A. The nominal steady-state P/T limits applicable up to 54 effective full power years (EFPY) are given in DCD Figures 5.3.2 and 5.3.3. The lowest Appendix G limit from these curves is 621 psig. The RNS system design pressure is 900 psig, and therefore the system pressure limit is 990 psig. Therefore, the lowest of the two pressure limits (621 psig) is used as the limit in the sizing of the RNS relief valve.

B. & C. The energy input transient is the limiting event for an RCS temperature above 70 F. Below 70 F, the mass input transient is more limiting. The energy input transient is analyzed using a specialized version of the LOFTRAN computer code (Reference 1), which has the capability to model the RNS relief valve. The peak pressure in the RNS system is calculated using the methodology as described in Reference 2 except that the RNS relief valve instead of the pressurizer PORV is used to mitigate the energy input transient.

Based on the energy input transient, the minimum RNS relief valve capacity of 850 gpm has been calculated at an RCS pressure equivalent to the valve setpoint of 500 psig plus 10% accumulation (550 psig). With this setpoint and capacity, the relief valve mitigates the limiting LTOP transient while maintaining the RCS pressure less than the Appendix G limit. Since the relief valve is located on the RNS pump suction line, the set pressure must account for the RNS pump head to maintain the RNS discharge piping below the system design pressure. Pressure losses in the flow path and the static pressure difference between the RNS suction piping and the relief valve are also considered in establishing the relief valve set pressure. The peak

pressure at the inlet to the RNS relief valve is 586 psig. The corresponding peak pressures at the reactor vessel mid plane and at the discharge of the RNS pump are no higher than 614 psig and 786 psig, respectively.

The minimum required capacity of the RNS relief valve based on the energy input transient is 850 gpm. Since the maximum flow rate for the mass input transient is 177 gpm, the RNS relief valve will be adequate to mitigate the mass input transient without overpressurizing the RNS system. The peak pressure at the inlet to the RNS relief valve will be no higher than the RNS relief valve full open pressure of 550 psig. The corresponding peak pressures at the reactor vessel mid plane and at the discharge of the RNS pump are no higher than 589 psig and 750 psig, respectively.

Single active failure is not considered for passive valves such as the RNS self-actuated spring relief valve. Therefore, the analysis does not consider a single failure of this valve. Also, no single active failure can occur in the RNS that could prevent the RNS suction relief valve from performing its function.

The 10% setpoint accumulation includes a 3% setpoint uncertainty. No other uncertainties are explicitly modeled in the analysis.

D. The LTOP enable temperature is based on utilizing the pressurizer safety valves for RCS overpressure protection when the RCS temperature is above 275 F (Technical Specification LCO 3.4.15). Once the RCS temperature reaches 275 F the RCS pressure can exceed the pressurizer safety valve set point pressure (2500 psig) and still be in the acceptable operating range according to the pressure/temperature curves (DCD Figures 5.3-2 and 5.3-3). The RCS pressure transients described in DCD section 15.2.3 confirm that the pressurizer safety valves are adequately sized to provide RCS overpressure protection.

In addition to responses to the three specific NRC follow-on comments above, Westinghouse is providing revised information on the analyses of Loss of Normal RHR Cooling in Mode 4 With RCS Intact.

In the Westinghouse Revision 1 response to this DSER Open Item, it was stated that the impact of the revised normal RHR system relief valve setpoint and capacity on the analyses of a loss of normal RHR cooling in Mode 4 with the RCS intact was being evaluated. The revised analyses for the two cases have been completed. The first case allowed for automatic safety system actuation on a low pressurizer level signal late in the event. The second case assumes operator action to actuate the Core Makeup Tanks and Passive RHR Heat Exchanger 1800 seconds after the loss of RNS cooling.

The conclusion from the revised analyses is that the consequences of a loss of RNS in Mode 4 with the RCS intact are acceptable for both cases, which is the same conclusion reported for the previous RNS system relief valve setpoint and capacity.

DCD subsection 19E.4.8.2 will be revised to include the results of the revised analyses, as shown below in the DCD Revisions From Revision 2 Response.

Design Control Document (DCD) Revisions From Revision 1 Response

Pages 8 through 21 provide DCD revisions resulting from the Revision 1 responses to this DSER Open Item

From DCD Revision 7, page 1.6-12, Table 1.6-6

Table 1.6-1 (Sheet 11 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
5.2	WCAP-8324-A	Control of Delta Ferrite in Austenitic Stainless Steel Weldments, June 1975
	WCAP-8693	Delta Ferrite in Production Austenitic Stainless Steel Weldments, January 1976
5.3	WCAP-15557	Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology, August 2000
	WCAP-14040-NP-A	**Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves**
5.4	WCAP-15994-P (P) WCAP-15994-NP	Structural Analysis Summary for the AP1000 Reactor Coolant Pump High Inertia Flywheel, March 2003

From DCD Revision 7, page 5.2-7, Section 5.2.2.2:

Subsection 5.4.9 discusses the capacities of the pressurizer safety valves and residual heat removal system relief valve used for low temperature overpressure protection. The setpoints and reactor trip signals which occur during operational overpressure transients are discussed in subsection 5.4.5. With the current AP1000 pressure-temperature limits (subsection 5.3.3), the set pressure for the relief valve in the normal residual heat removal system is based on a sizing analysis performed to prevent the reactor coolant system pressure from exceeding ~~110 percent of the design pressure of the normal residual heat removal system~~**the applicable low temperature pressure limit for the reactor vessel based on ASME Code, Section III, Appendix G.** The limiting mass and energy input transients are assumed for the sizing analysis.

From DCD Revision 7, page 5.3-13, Section 5.3.3.1:

The pressure-temperature curves are developed considering a radiation embrittlement of up to 54 effective full power years (EFPY) consistent with an expected plant design life of 60 years with 90 percent availability. Copper, nickel contents and initial RT_{NDT} for materials in the reactor vessel beltline region and the reactor vessel flange and the closure head flange region are shown in Tables 5.3-1

and 5.3-3. The operating curves are developed with the methodology given in Reference 6, which is in accordance with 10 CFR 50, Appendix G with the following exceptions:

1. The fluence values used are calculated fluence values (i.e., comply with Regulatory Guide 1.190), not the best-estimate fluence values.

2. The K_{Ic} critical stress intensities are used in place of the K_{Ia} critical stress intensities. This methodology is taken from approved ASME Code Case N-641 (which covers Code Cases N-640 and N-588).

3. The 1996 Version of Appendix G to Section XI is used rather than the 1989 version.

~~4. The flange requirement is not considered per Reference 7.~~

From DCD Revision 7, page 5.3-23:

5.3.7 References

1. ASTM E-185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels."

2. Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," United States Nuclear Regulatory Commission, Office of Nuclear Reactor Research, March, 2001.

3. WCAP-15557, "Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology," S. L. Anderson, August 2000.

4. NRC Policy Issue, "Pressurized Thermal Shock," SECY-82-465, November 23, 1982.

5. Theofanous, T.G., et al., "In-Vessel Coolability and Retention of a Core Melt," DOE/ID-10460, July 1995.

6. WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," J. D. Andrachek, et al., January 1996.

~~7. WCAP-15315, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Operating PWR and BWR Plants," W. Bamford, et al., October 1999.~~

From DCD Revision 7, page 5.3-32:

Current Figure 5.3-2

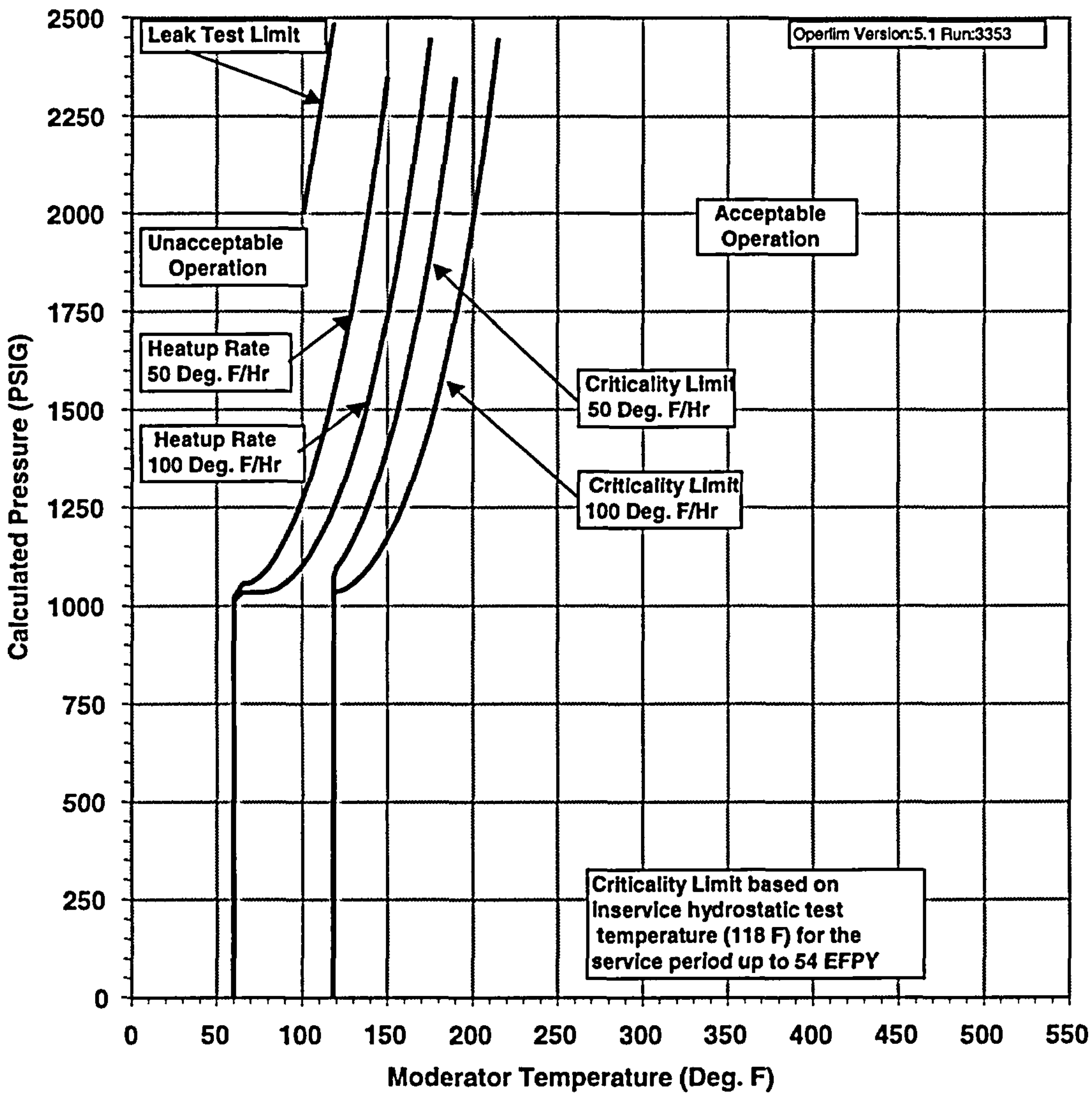


Figure 5.3-2

AP1000 Reactor Coolant System Heatup Limitations (Heatup Rate Up to 50 and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

Revised Figure 5.3-2

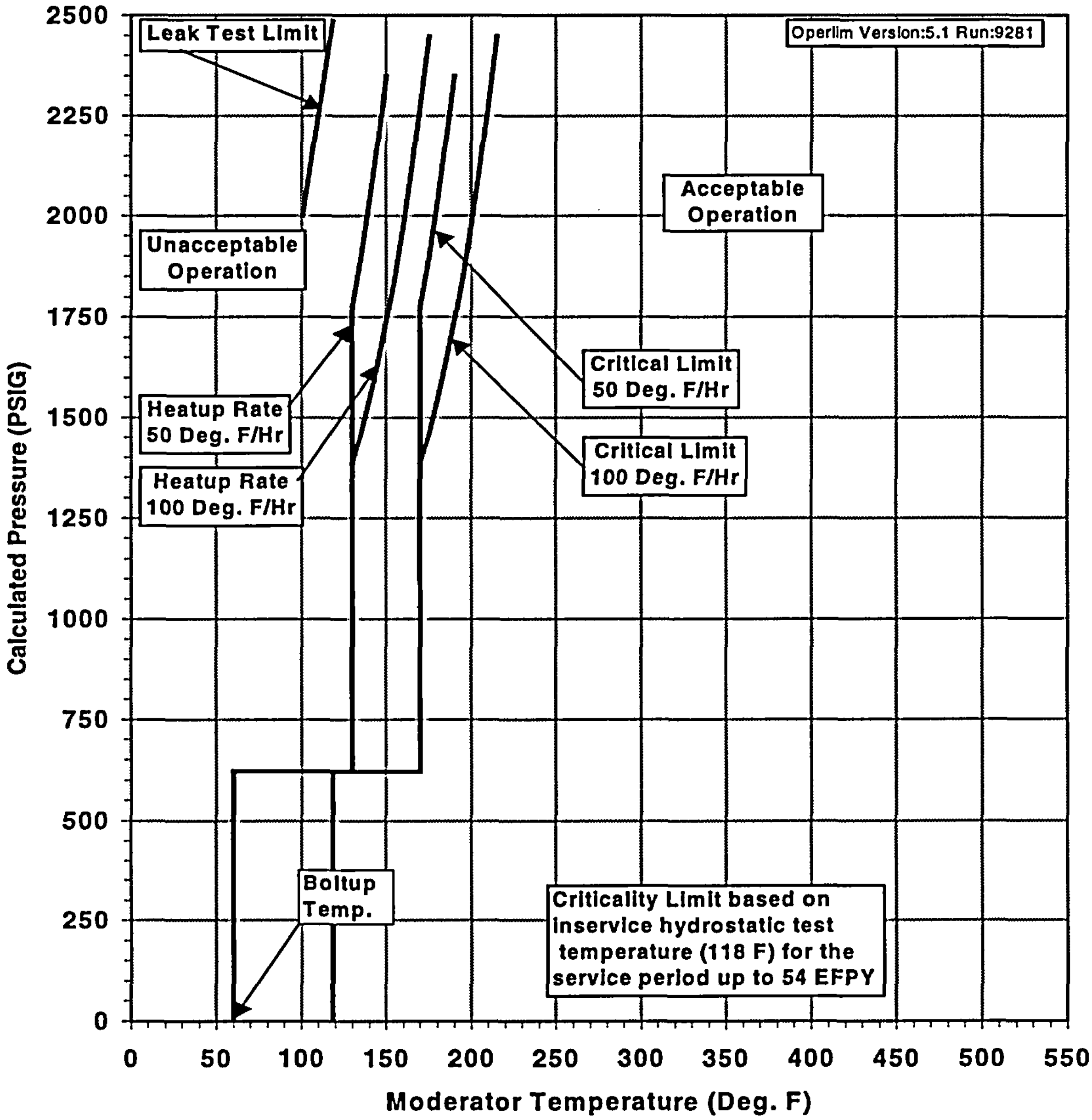


Figure 5.3-2

AP1000 Reactor Coolant System Heatup Limitations (Heatup Rate Up to 50 and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

From DCD Revision 7, page 5.3-33:

Current Figure 5.3-3

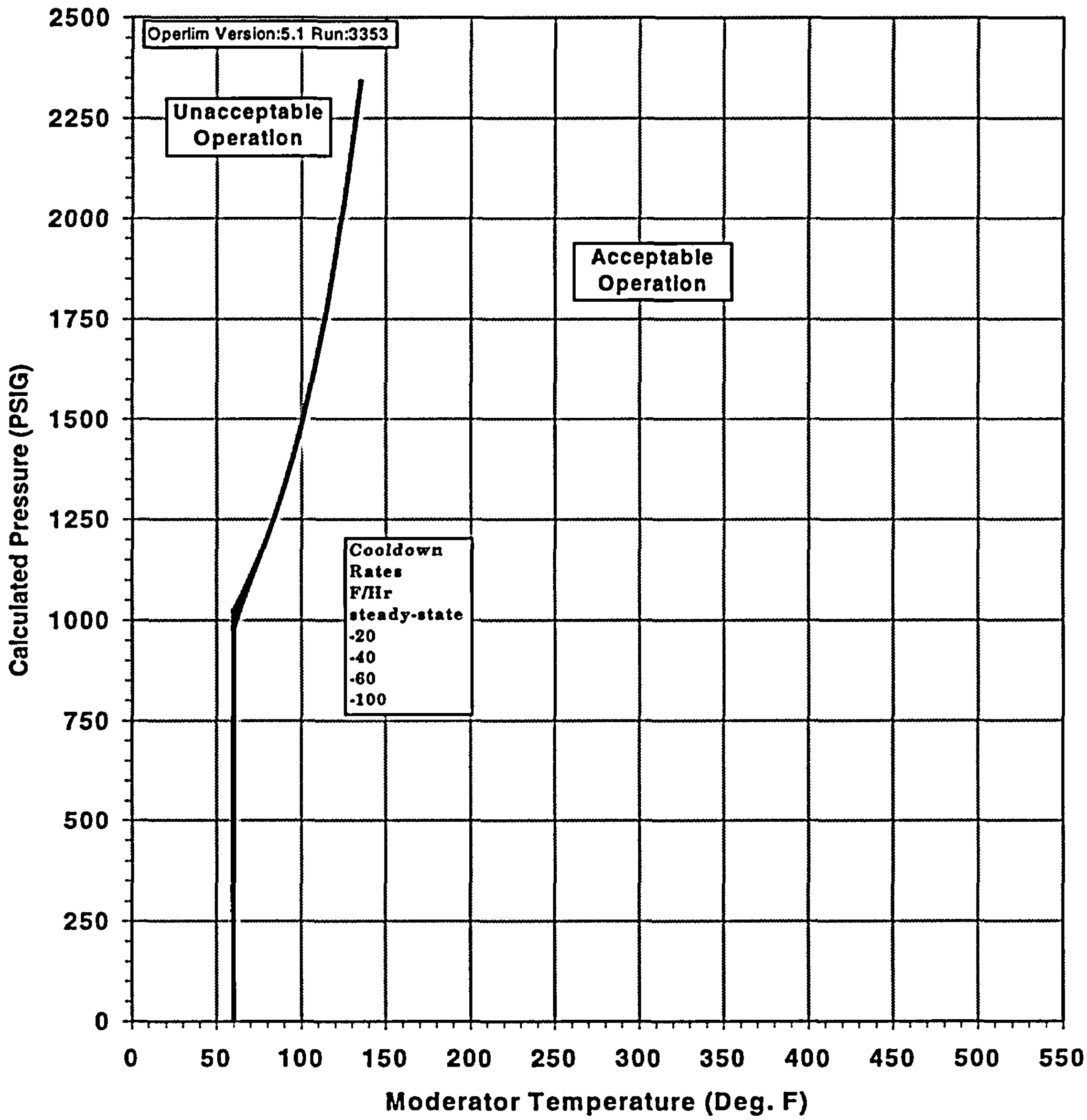


Figure 5.3-3

AP1000 Reactor Coolant System Cooldown Limitations (Cooldown rates up to 50 and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

Revised Figure 5.3-3

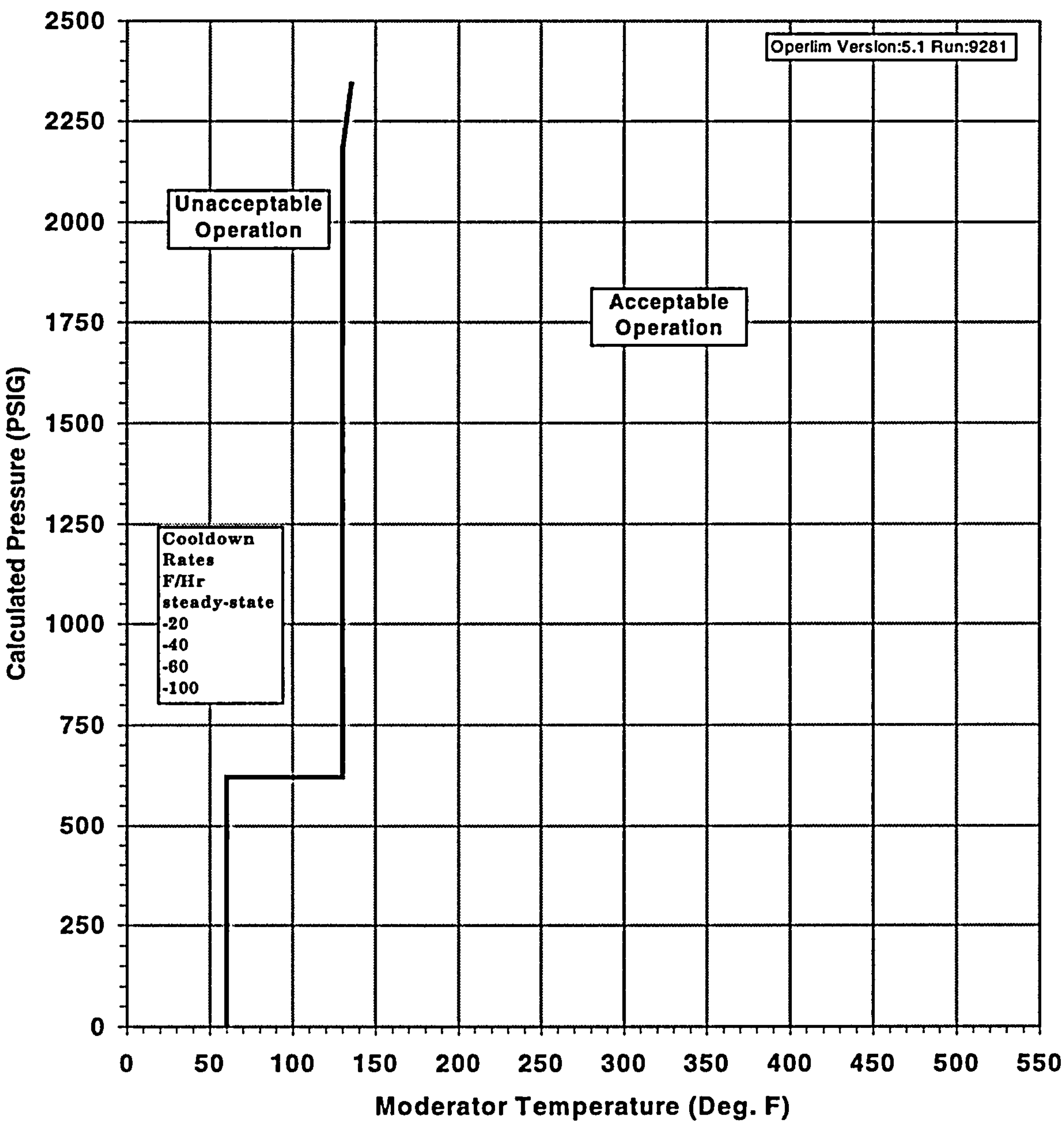


Figure 5.3-3

AP1000 Reactor Coolant System Cooldown Limitations (Cooldown Rates up to 50 and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

From DCD Revision 7, page 5.4-61, Section 5.4.9.3:

The relief valve on the normal residual heat removal system has an accumulation of 10 percent of the set pressure. *The set pressure is the lower of the pressure based on the design pressure of the residual heat* removal system and the pressure based on the reactor vessel low temperature pressure limit. The pressure limit determined based on the design pressure includes the effect of the pressure rise across the pump. The set pressure in Table 5.4-17 is based on the ~~design pressure of the residual heat removal system~~**reactor vessel low temperature pressure limit**. The lowest permissible set pressure is based on the required net positive suction head for the reactor coolant pump.

From DCD Revision 7, page 5.4-93:

Table 5.4-17

PRESSURIZER SAFETY VALVES - DESIGN PARAMETERS

Number	2
Minimum required relieving capacity per valve (lb/hr)	750,000 at 3% accumulation
Set pressure (psig)	2485 ±25 psi
Design temperature (°F)	680
Fluid	Saturated steam
Backpressure	
Normal (psig)	3 to 5
Expected maximum during discharge (psig)	500
Environmental conditions	
Ambient temperature (°F)	50 to 120
Relative humidity (percent)	0 to 100

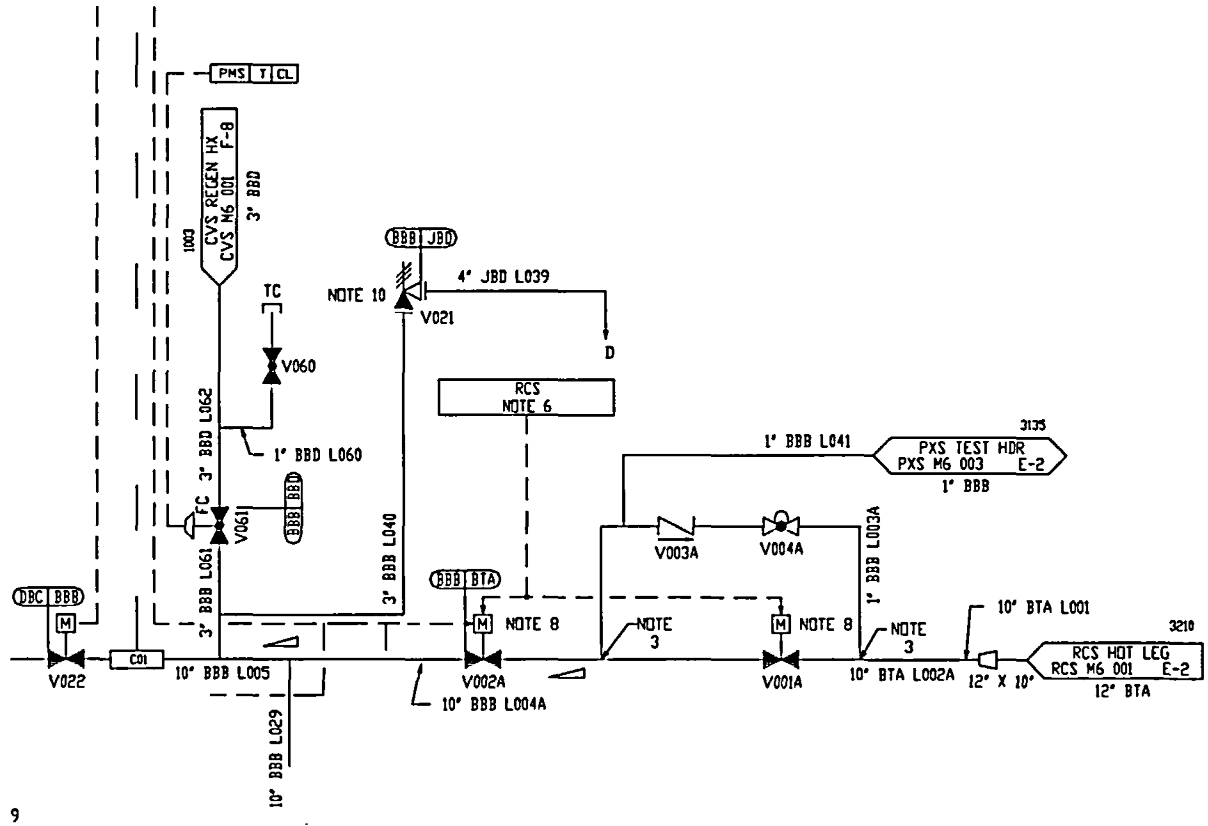
Residual Heat Removal Relief Valve - Design Parameters

Number	1
Nominal relieving capacity per valve, ASME flowrate (gpm)	~~750~~850
Nominal set pressure (psig)	~~636~~500*
Full-open pressure, with accumulation (psig)	~~700~~550*
Design temperature (°F)	400
Fluid	Reactor coolant
Backpressure	
Normal (psig)	3 to 5
Expected maximum during discharge (psig)	200
Environmental conditions	
Ambient temperature (°F)	50 to 120
Relative humidity (percent)	0 to 100

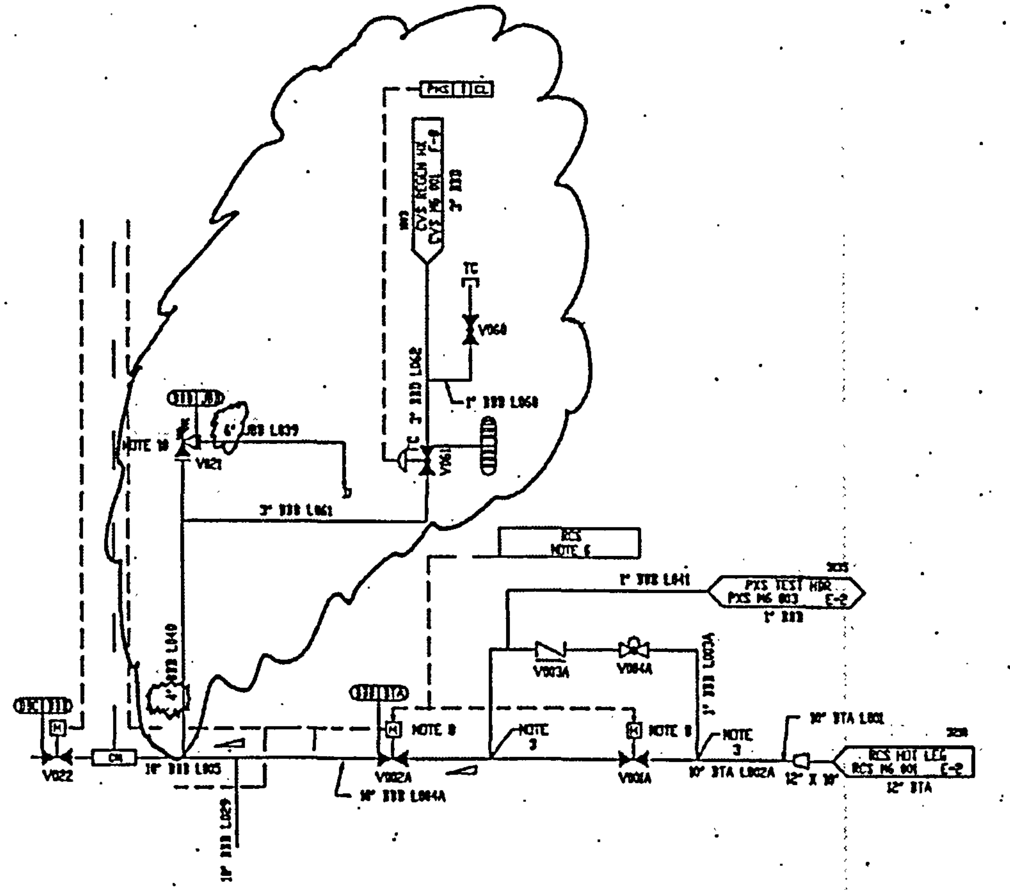
* See text (5.4.9.3) for discussion of set pressure

From DCD Revision 7, page 5.4-107:

Current Figure 5.4-7 Normal Residual Heat Removal System Piping and Instrument Diagram



Revised Figure 5.4-7 Normal Residual Heat Removal System Piping and Instrument Diagram



From DCD Revision 7, page 3.4.14-1, Section 16.1 Technical Specifications, LTOP System:

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.14 At least one of the following Overpressure Protection Systems shall be OPERABLE, with the accumulators isolated:

a. The Normal Residual Heat Removal System (RNS) suction relief valve, or

b. The RCS depressurized and an RCS vent of ≥ [~~5.~~49.3] square inches.

- NOTE -

When the RCS temperature is ≥ 200°F, a reactor coolant pump (RCP) may not be started if the pressurizer level is ≥ 92%.

From DCD Revision 7, page 3.4.14-2, Section 16.1 Technical Specifications, LTOP System:

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. The RNS suction relief valve inoperable.	C.1	Restore the RNS suction relief valve to OPERABLE status.	12 hours
	<u>OR</u>		
	C.2	Depressurize RCS and establish RCS vent of ≥ [~~5.~~49.3] square inches.	12 hours

From DCD Revision 7, page 3.4.14-3, Section 16.1 Technical Specifications, LTOP System:

	SURVEILLANCE	FREQUENCY
SR 3.4.14.3	-- - NOTE - Only required to be performed when complying with LCO 3.4.14.b. -- Verify RCS vent ≥ [~~5.4~~9.3] square inches is open.	12 hours for unlocked-open vent AND 31 days for locked-open vent
SR 3.4.14.4	Verify the lift setting of the RNS suction relief valve.	In accordance with the Inservice Testing Program

From DCD Revision 7, page B 3.4.14-3, Section 16.1 Technical Specifications, Basis 3.4.14, LTOP System:

RNS Suction Relief Valve Performance

Since the RNS suction relief valve does not have a variable P/T lift setpoint, the analysis must show that with chosen setpoint, the relief valve will pass flow greater than that required for the limiting LTOP transient while maintaining RCS pressure less than the minimum of either the P/T limit curve or 110 percent of the design pressure of the normal residual heat removal system. The current analysis shows that up to a temperature of ~~100~~**70°F**, the mass input transient is limiting, and above this temperature the heat input transient is limiting.

From DCD Revision 7, page B 3.4.14-4, Section 16.1 Technical Specifications, Basis 3.4.14, LTOP System:

RCS Vent Performance

With the RCS depressurized, a vent size of [~~5.~~**49.3**] square inches is capable of mitigating a limiting overpressure transient. The area of the vent is equivalent to the area of the inlet pipe to the RNS suction relief valve so the capacity of the vent is greater than the flow possible with either the mass or heat input transient, while maintaining the RCS pressure less than the minimum of either the maximum pressure on the P/T limit curve or 110 percent of the design pressure of the normal residual heat removal system.

The required vent area may be obtained by opening one ADS **Stage 2, 3, or 4** flow path.

The RCS vent size will be reevaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

From DCD Revision 7, page B 3.4.14-4&5, Section 16.1 Technical Specifications, Basis 3.4.14, LTOP System:

The elements of the LCO that provide low temperature overpressure mitigation thr pressure relief are:

a. One OPERABLE RNS suction relief valve; or

   An RNS suction relief valve is OPERABLE for LTOP when both RNS suction isolation valves in one flow path are open, its setpoint is within limits, and testing has proven its ability to open at this setpoint.

LCO (continued)

b. A depressurized RCS and an RCS vent.

   An RCS vent is OPERABLE when open with an area of ≥ [~~5.~~**49.3**] square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

From DCD Revision 7, page B 3.4.14-7, Section 16.1 Technical Specifications, Basis 3.4.14, LTOP System:

<u>SR 3.4.14.3</u>

The RCS vent of ≥ [~~5.~~49.3] square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked (valves that are sealed or secured in the open position are considered "locked" in this context) or

b. Once every 31 days for other vent path(s) (e.g., a vent valve that is locked, sealed, or secured in position or a removed pressurizer safety valve or open manway also fits this category).

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.14b.

PRA Revision:

None

Design Control Document (DCD) Revisions From Revision 2 Response

Pages 23 through 44 provide DCD revisions resulting from the Revision 2 responses to this DSER Open Item

From DCD Revision 7, Tier 1, Section 2.3.6, Table 2.3.6-4, page 2.3.6-12:

Table 2.3.6-4 (cont)

Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9.a) The RNS provides LTOP for the RCS during shutdown operations.	i) Inspections will be conducted on the low temperature overpressure protection relief valve to confirm that the capacity of the vendor code plate rating is greater than or equal to system relief requirements.	i) The rated capacity recorded on the valve vendor code plate is not less than the flow required to provide low-temperature overpressure protection for the RCS, as determined by the LTOPS evaluation based on the P/T curves developed for the as-procured reactor vessel material.
	ii) Testing and analysis in accordance with the ASME Code Section III will be performed to determine set pressure.	ii) A report exists and concludes that the relief valve opens at a pressure ~~such that the relief capacity is not less than the flow required~~**not greater than the set pressure** required to provide low-temperature overpressure protection for the RCS, **as determined by the LTOPS evaluation based on the P/T curves developed for the as-procured reactor vessel material.**

From DCD Revision 7, subsection 19E.4.8.2, page 19E-35a:

Automatic Safety Injection Actuation Case

The accident analyzed is a loss of RNS cooling, which is assumed to result in a complete loss of heat removal for the RCS. The sequence of events for this analysis is presented in Table 19E.4.8-2.

Following the loss of RNS cooling, there is no mechanism for heat removal from the RCS. The core decay heat generation causes the reactor coolant temperature and pressure to increase. Although the MSS is assumed to be unavailable for heat removal, the steam generators represent a heat sink that slows the rate of heatup of the reactor coolant. The fluid temperature at the core outlet for the transient is shown in Figure 19E.4.8-7. The reactor coolant heatup causes the system pressure to increase, as shown in Figure 19E.4.8-8, until the pressure reaches the RNS relief valve setpoint of ~~818~~ **500** psig (~~832.7~~**514.7** psia) at approximately ~~2750~~ **400** seconds. The normal relieving capacity of the RNS relief valve is ~~650~~ **850** gpm, and the pressure is maintained at the relief valve setpoint as the temperature continues to increase and reactor coolant is discharged from the relief valve. Flow out the relief valve is shown in Figure 19E.4.8-9. The expansion of the water due to the coolant temperature increase also causes the pressurizer level to increase slightly as shown in Figure 19E.4.8-10.

The loss of reactor coolant through the relief valve is not sufficient to remove the core decay heat, and the reactor coolant temperature continues to increase until the core outlet temperature reaches saturation at the relief valve setpoint at approximately ~~5000~~ **3200** seconds. The generation of steam in the core causes the system pressure to increase above the RNS relief valve setpoint and the pressurizer level to continue to increase. A mixture level begins to form in the upper plenum at approximately ~~5520~~ **3800** seconds and drops to the top of the hot-leg elevation as shown in Figure 19E.4.8-11. At about ~~5540~~ **4100** seconds, enough mass has been discharged such that a mixture level also forms in the downcomer (Figure 19E.4.8-12) and the downcomer two-phase level begins to decrease. As the boiling front moves lower and lower into the core, more steam generation occurs and the pressure continues to increase. Once the entire core length is boiling, the upper plenum mixture level is within the hot-leg perimeter. At approximately ~~9100~~ **7000** seconds, when steam begins to flow through the relief valve along with liquid, the pressure begins to decrease. The pressurizer level also begins to decrease as water drains from the pressurizer into the reactor coolant system hot leg. However, the voiding in the RCS increases as the pressure decreases, and flashing begins to occur in the pressurizer at approximately ~~9300~~ **7300** seconds. This additional steam generation causes the pressure to begin to increase, and the relief valve flow becomes solely liquid again. The steam voiding in the pressurizer not only causes the pressure increase, but also facilitates draining, and the pressurizer level continues to decrease.

As the pressurizer level decreases, a CMT actuation signal is generated automatically on low pressurizer level. Following a 1.2-second delay, the isolation valves on the available CMT tank delivery lines open and CMT injection flow is initiated at approximately ~~10,600~~ **7910** seconds as shown in Figure 19E.4.8-13. The opening of the PRHR HX isolation valve on a CMT actuation signal starts the flow through the heat exchanger. The CMT injection causes the reactor coolant pressure to decrease below the RNS relief valve setpoint, and the loss of reactor coolant is terminated at approximately ~~10,900~~ **8100** seconds. As the CMT level decreases (Figure 19E.4.8-14), the first-stage ADS setpoint at 67.5 percent is reached at ~~10,847~~ **9348** seconds. The second-stage and third-stage ADS valves also open following the timer delays for the actuation of the second-stage and third-stage ADS valves. The vapor and liquid flow through the ADS valves (Figures 19E.4.8-15 and 19E.4.8-16) results in a rapid depressurization of the reactor coolant system. The CMT reaches the fourth-stage ADS setpoint of 20 percent, and two of the four fourth-stage paths open

at ~~11,900~~**10,225** seconds. As noted previously, it is assumed that one of the fourth-stage paths is out of service and one path is assumed to fail as the single active failure. The vapor and liquid flow through the fourth-stage ADS paths (Figures 19E.4.8-17 and 19E.4.8-18) further reduces the pressure to the point where IRWST injection begins at approximately ~~12,200~~**10,700** seconds (Figure 19E.4.8-19).

The CMT and IRWST injection reverses the decrease in the core stack and downcomer mixture levels as shown in Figures 19E.4.8-11 and 19E.4.8-12, respectively. As shown in Figure 19E.4.8-11, the core stack mixture level is maintained ~~well~~ above the elevation of the top of the core active fuel (20.34 feet) throughout the transient. At the end of the transient, the core stack mixture level has been restored to within the hot-leg perimeter and the downcomer mixture level has been restored to the DVI nozzle elevation. The fluid temperature at the core outlet has also been reduced and is being maintained at less than 250°F. As shown in Figure 19E.4.8-20, the reactor coolant mass inventory twice reaches a minimum of approximately ~~130,000~~**110,000** pounds when the CMT and IRWST injection then increase the inventory. The reactor coolant mass inventory is greater than 200,000 pounds and is slowly increasing at the end of the transient. Thus, it is concluded that the consequences of a loss of RNS in Modes 4 and 5 with the RCS intact are acceptable.

Manual Safety Actuation

If operator action occurs after 1800 seconds, the CMT and PRHR isolation valves would open. Initially, the decay heat is greater than the PRHR capacity and the RCS pressure increases to the RNS safety valve setpoint (Figure 19E.4.8-21). At this time, RCS ~~a small amount of~~ inventory is vented through the valve (Figure 19E.4.8-22). Eventually, the decay heat matches the PRHR capacity (Figure 19E.4.8-42) and the RCS pressure decreases slowly to the valve setpoint. For this case, ~~no significant loss of inventory occurs and~~ the ADS is not actuated. The sequence of events for this case is also shown in Table 19E.4.8-2.

From DCD Revision 7, page 19E-45:

Table 19E.4.8-2

LOSS OF NORMAL RESIDUAL HEAT REMOVAL SYSTEM COOLING IN MODE 4 WITH REACTOR COOLANT SYSTEM INTACT – SEQUENCE OF EVENTS

Event	Automatic Actuation Time (seconds)	Manual Actuation Time (seconds)
Loss of RNS cooling	0	0
RNS relief valve flow starts	~~1400~~250	~~4950~~250
CMT and PRHR actuated	~~9500~~7910	1800
RNS relief valve flow terminated	~~9700~~8100	<1 lbm/s @ 25,000
ADS Stage 1 flow starts	~~10,075~~9348	–
ADS Stage 2 flow starts	~~10,145~~9418	–
ADS Stage 3 flow starts	~~10,265~~9538	–
ADS Stage 4 flow starts	~~10,895~~10,225	–
IRWST injection starts	~~11,845~~10,700	–

From DCD Revision 7, page 19E-58: **Current Figure 19E.4.8-7**

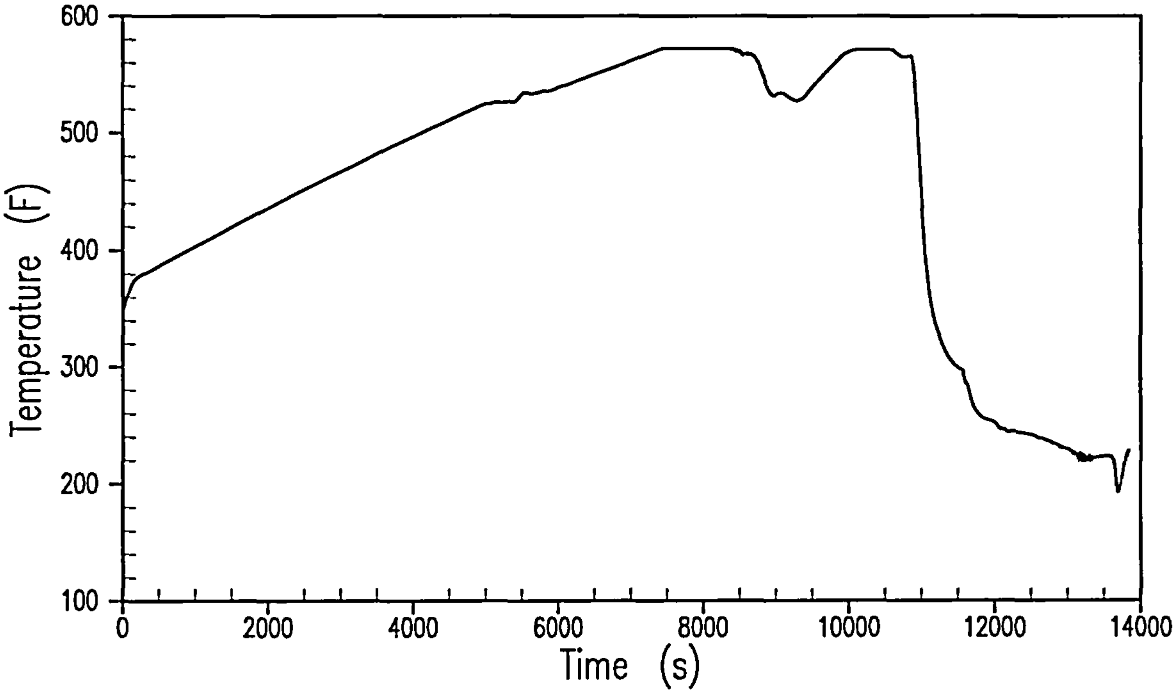
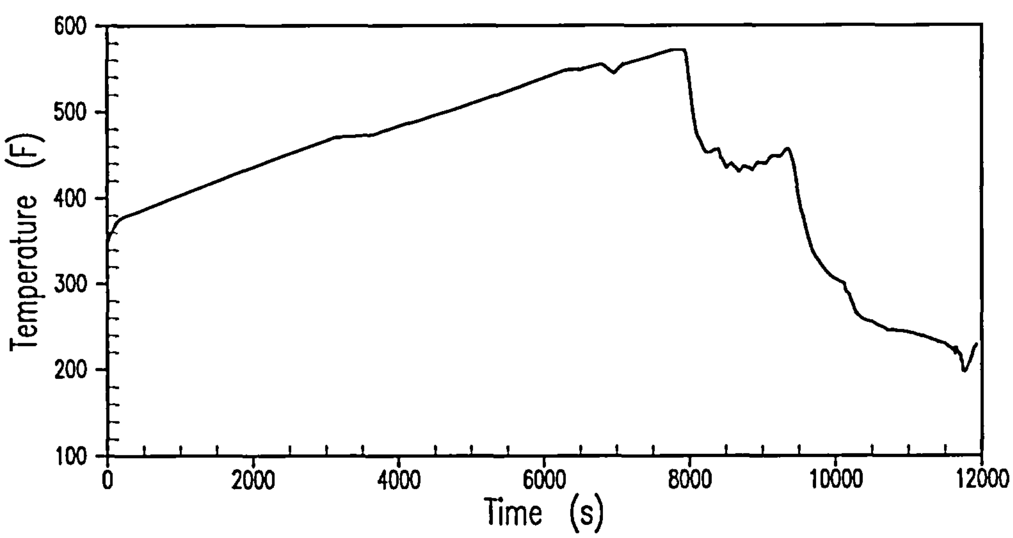


Figure 19E.4.8-7

Core Outlet Temperature, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-7



From DCD Revision 7, 19E-59: **Current Figure 19E.4.8-8**

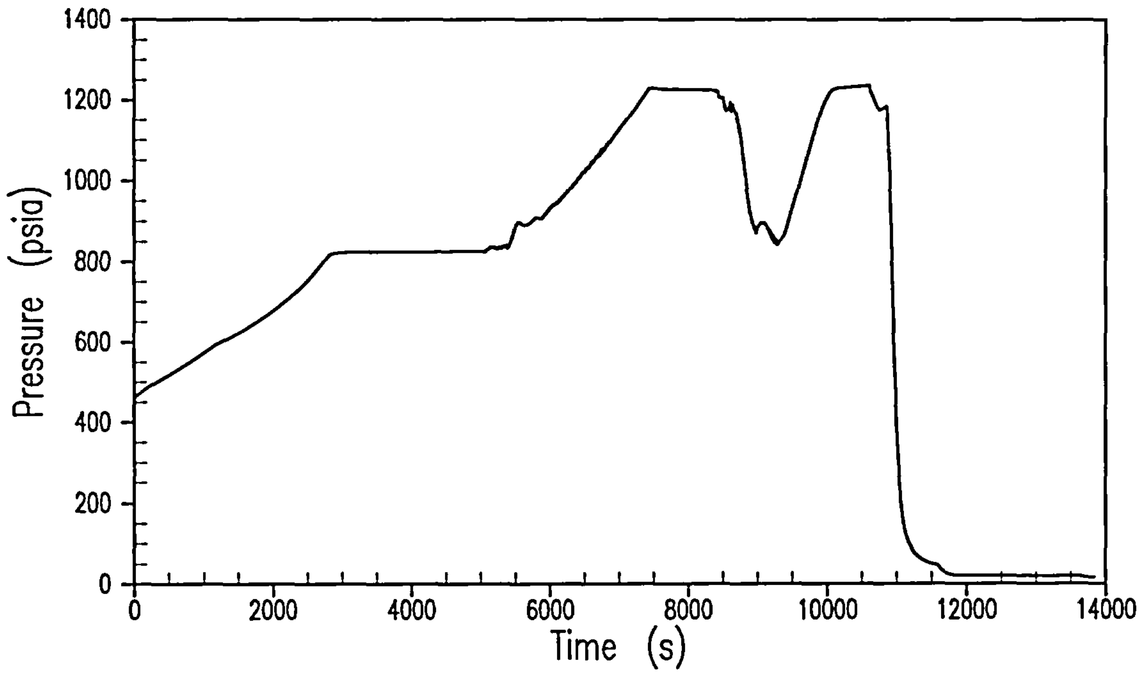
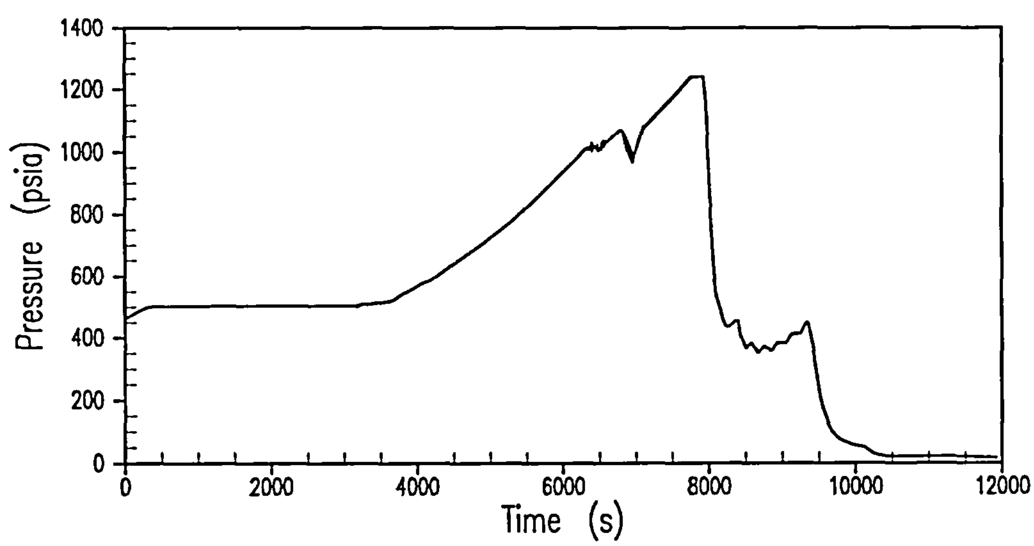


Figure 19E.4.8-8

Pressurizer Pressure, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-8



From DCD Revision 7, page 19E-60: **Current Figure 19E.4.8-9**

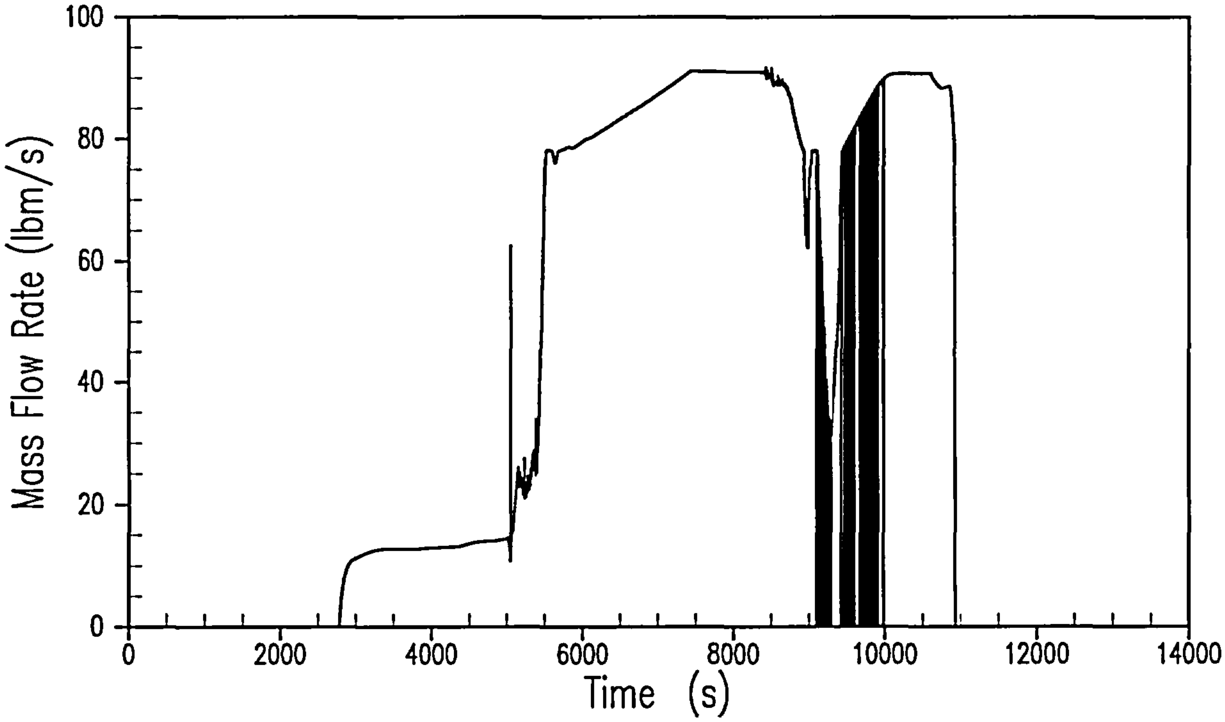
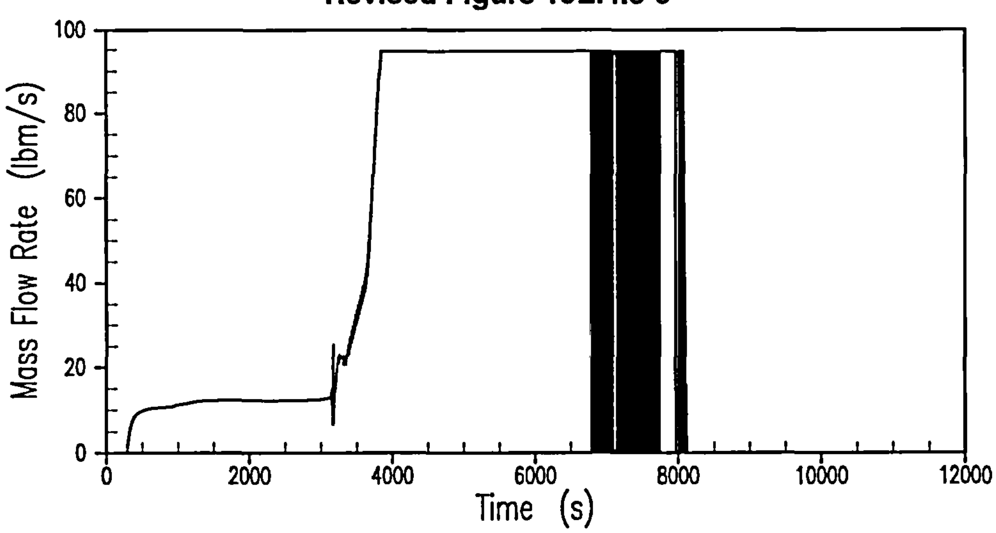


Figure 19E.4.8-9

RNS Relief Valve Flow, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-9



From DCD Revision 7, page 19E-61: **Current Figure 19E.4.8-10**

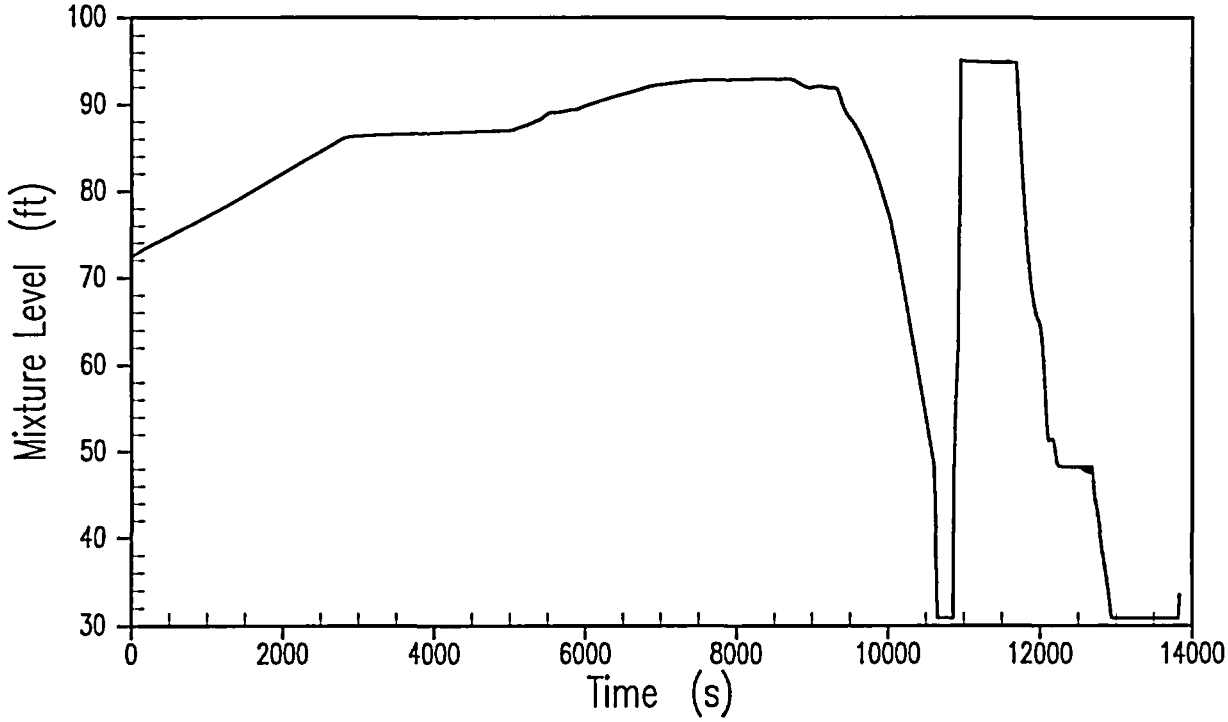
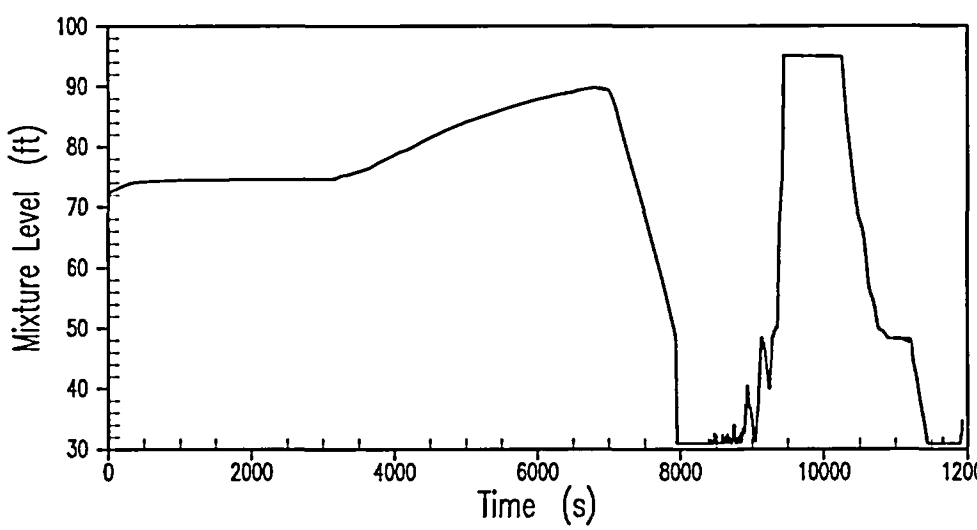


Figure 19E.4.8-10

Pressurizer Mixture Level, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-10



From DCD Revision 7, page 19E-62: **Current Figure 19E.4.8-11**

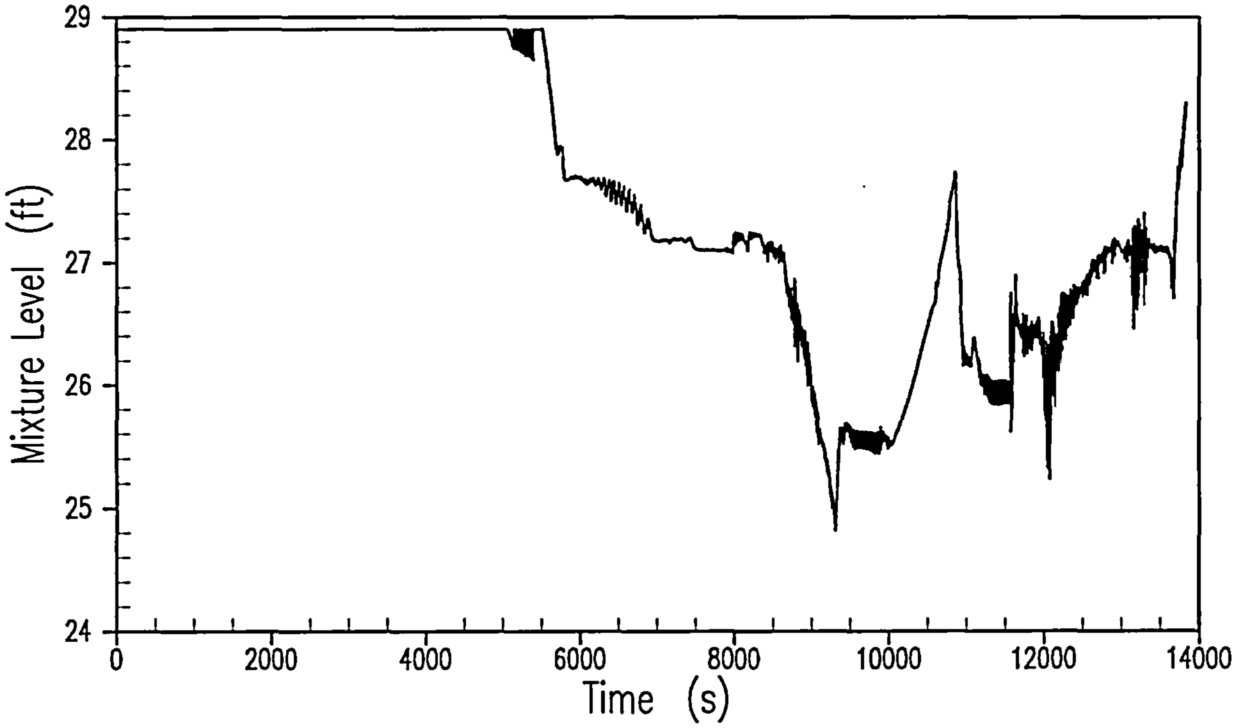
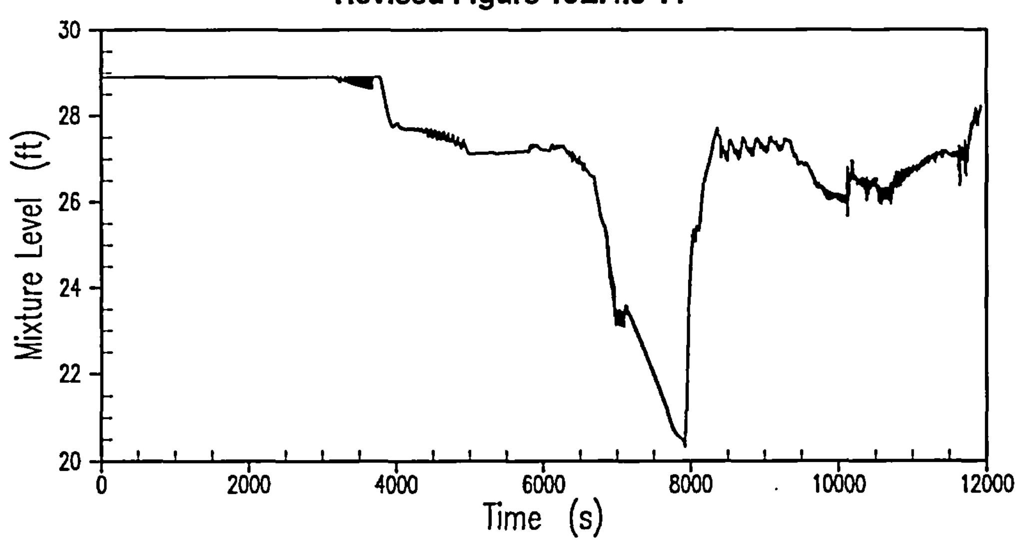


Figure 19E.4.8-11

Core Stack Mixture Level, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-11



From DCD Revision 7, page 19E-63: **Current Figure 19E.4.8-12**

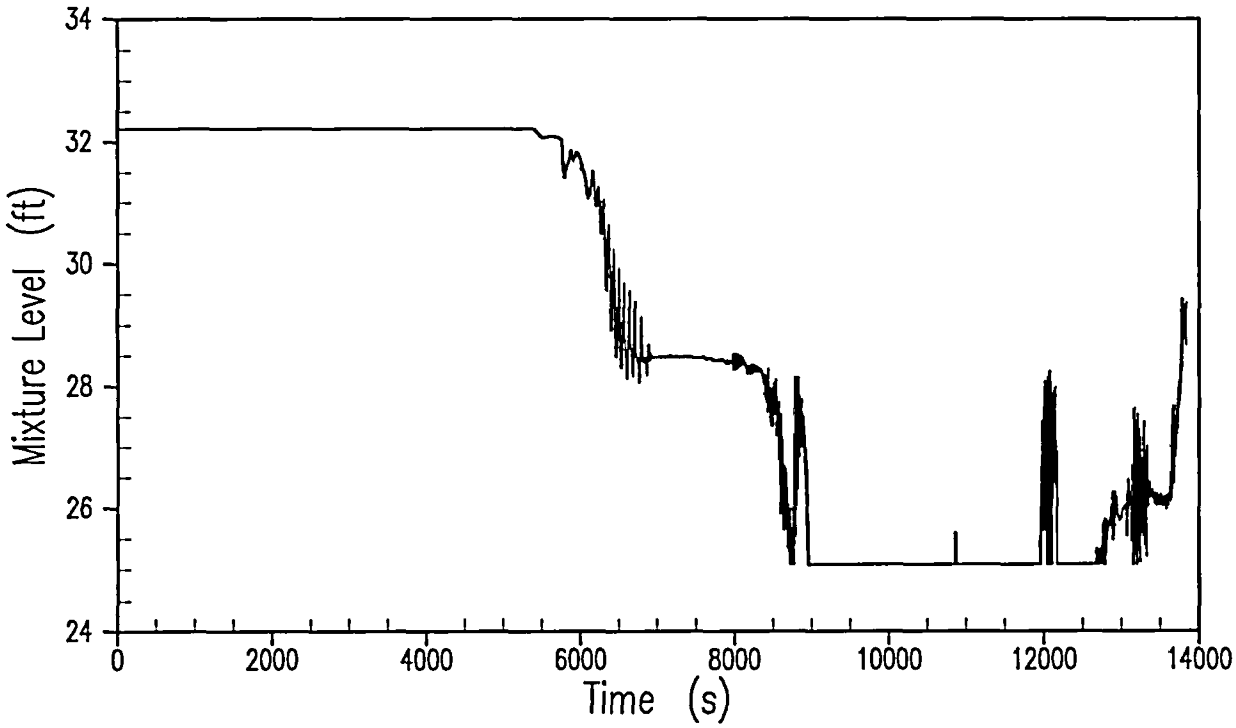
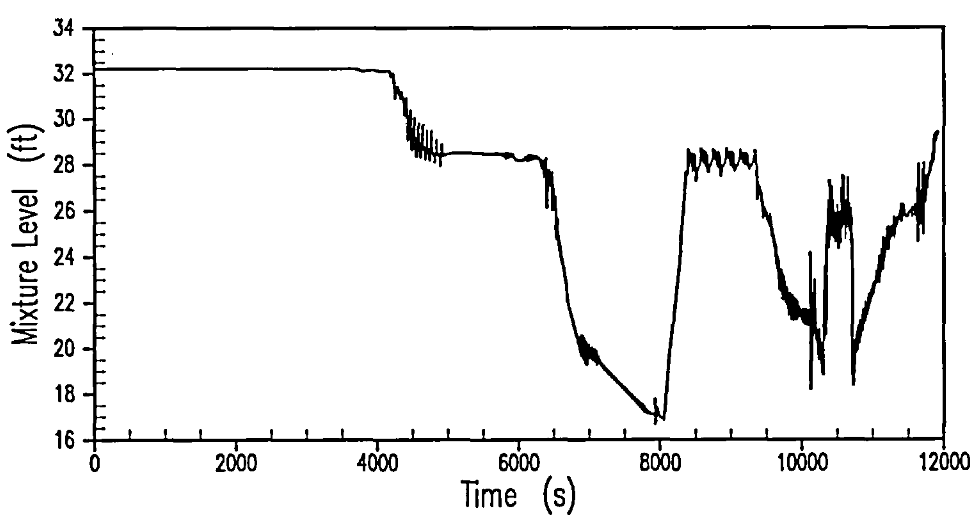


Figure 19E.4.8-12

Downcomer Mixture Level, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-12



From DCD Revision 7, page 19E-64: **Current Figure 19E.4.8-13**

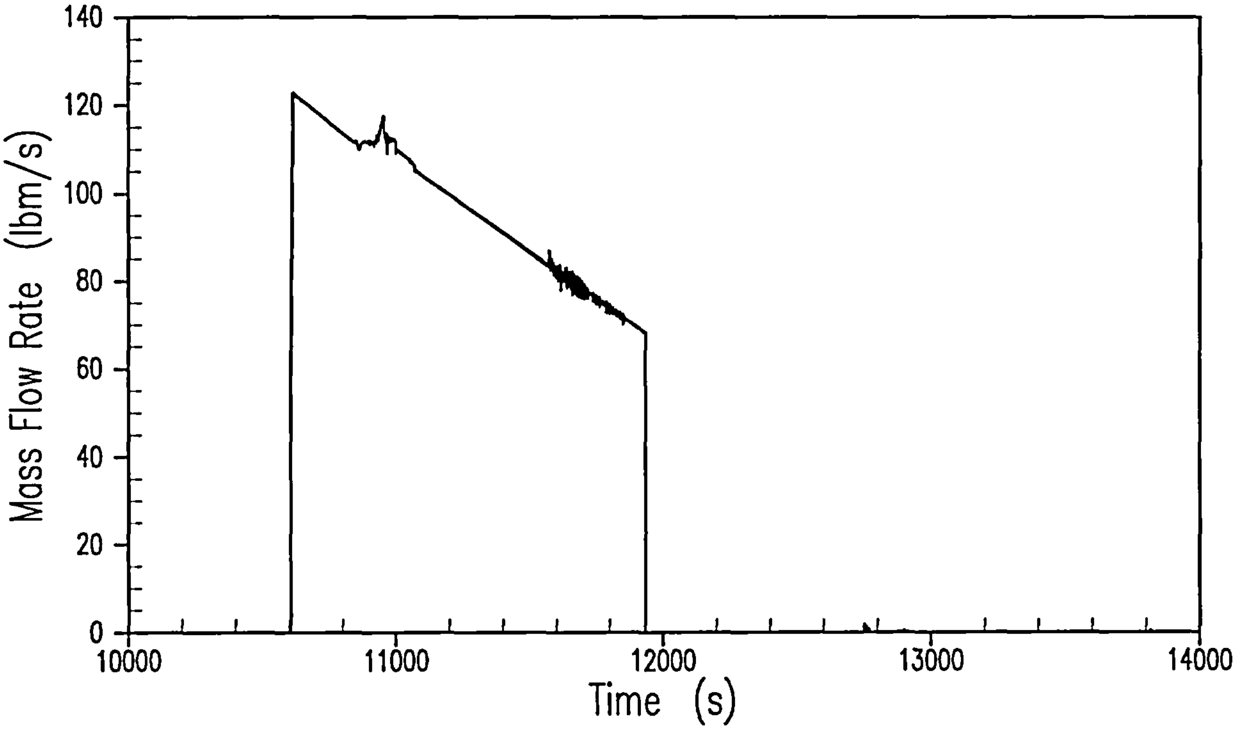
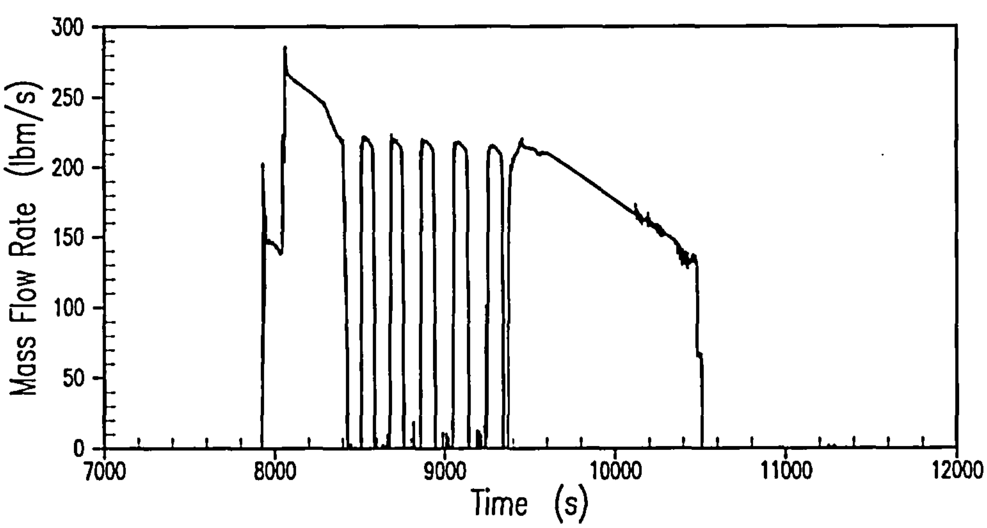


Figure 19E.4.8-13

CMT to DVI Flow, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-13



From DCD Revision 7, page 19E-65: **Current Figure 19E.4.8-14**

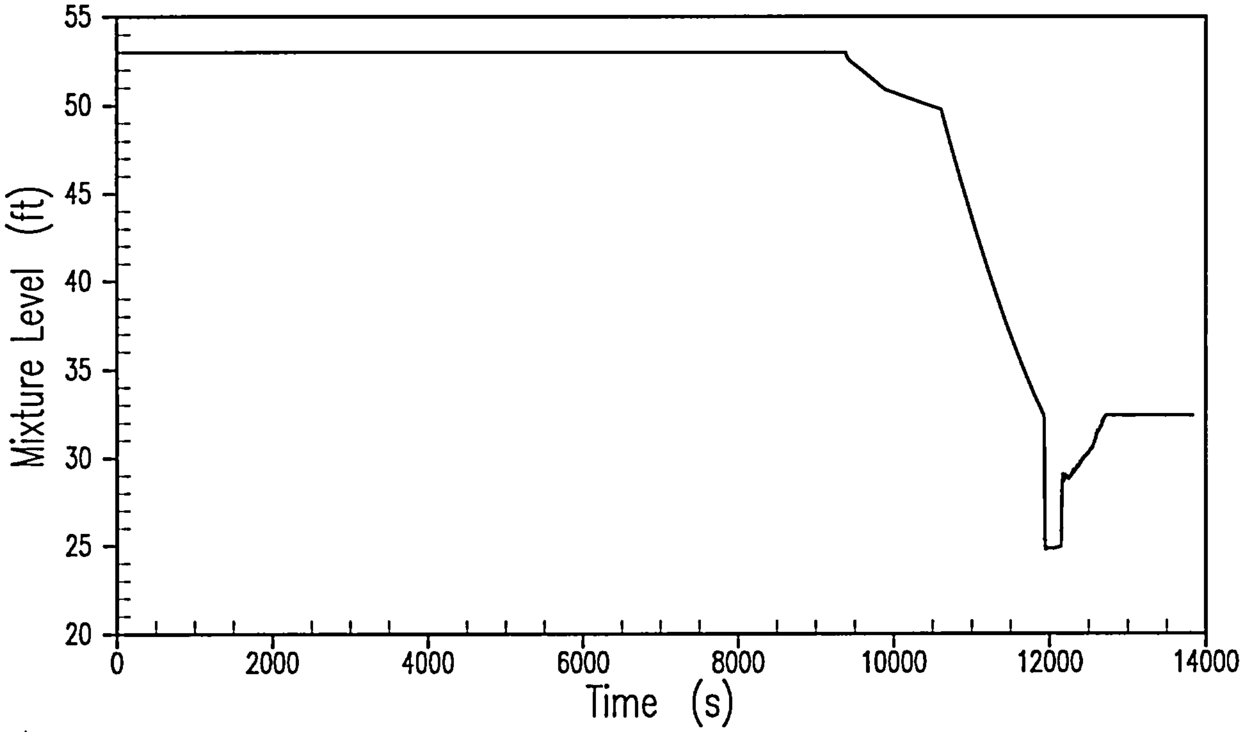
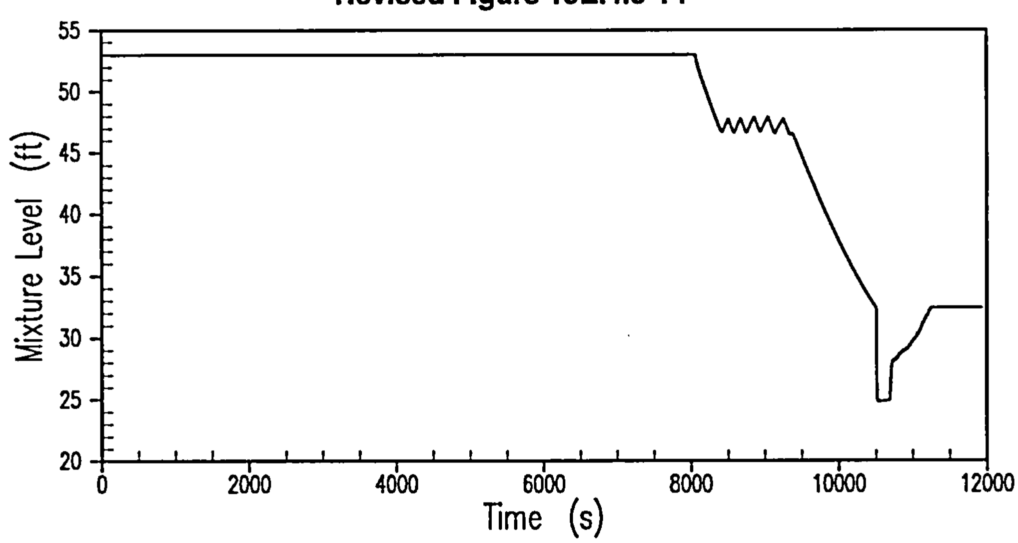


Figure 19E.4.8-14

CMT Mixture Level, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-14



From DCD Revision 7, page 19E-66: **Current Figure 19E.4.8-15**

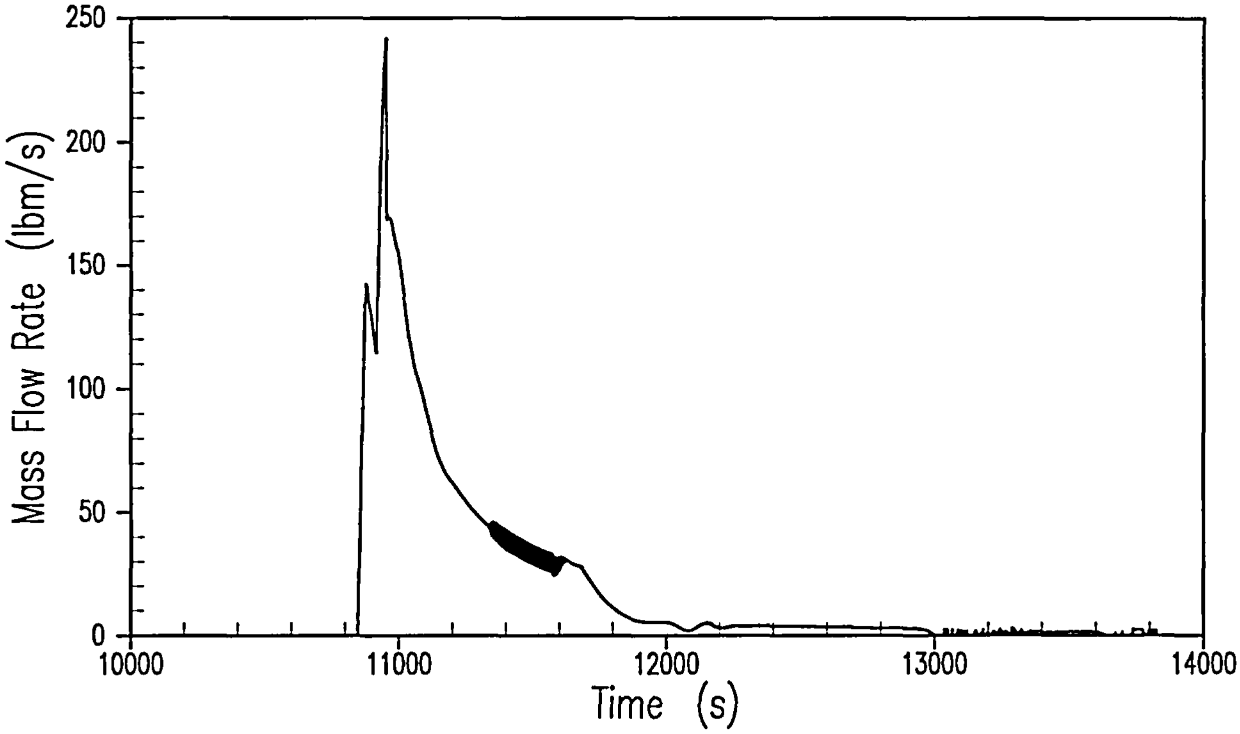
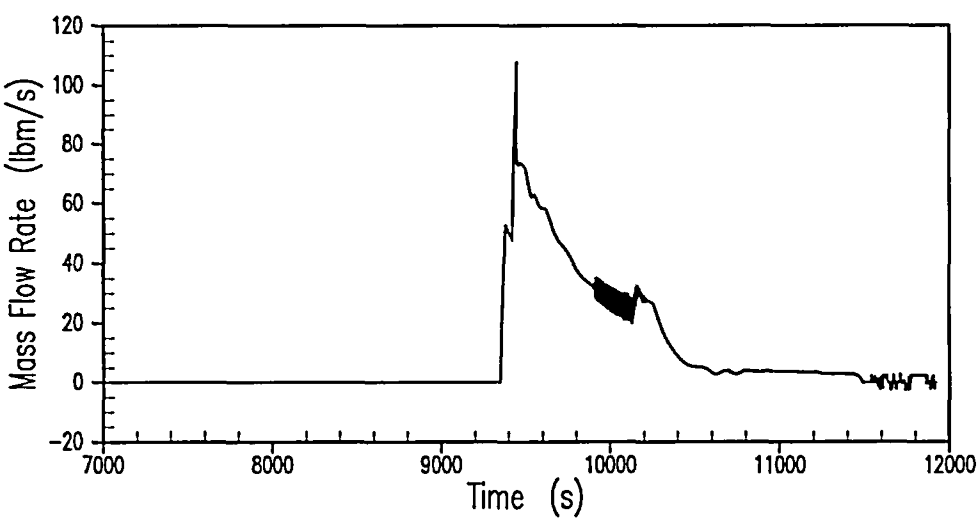


Figure 19E.4.8-15

ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-15



From DCD Revision 7, page 19E-67: **Current Figure 19E.4.8-16**

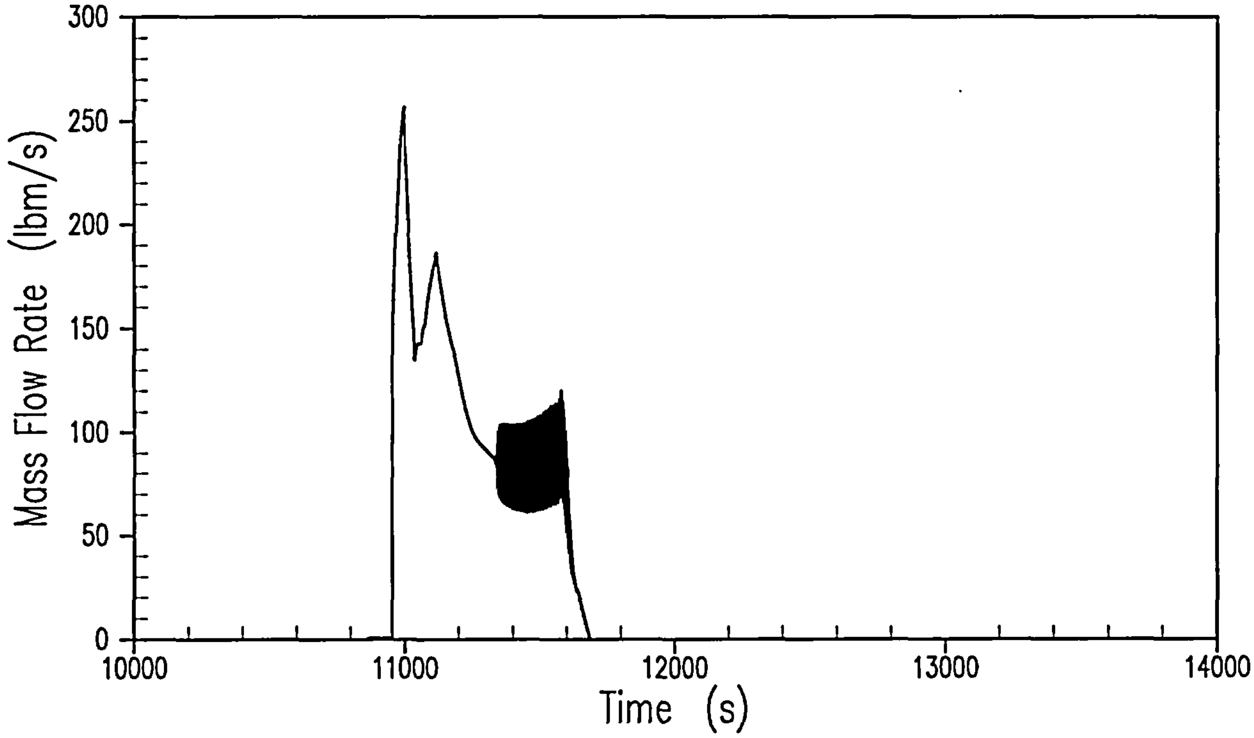
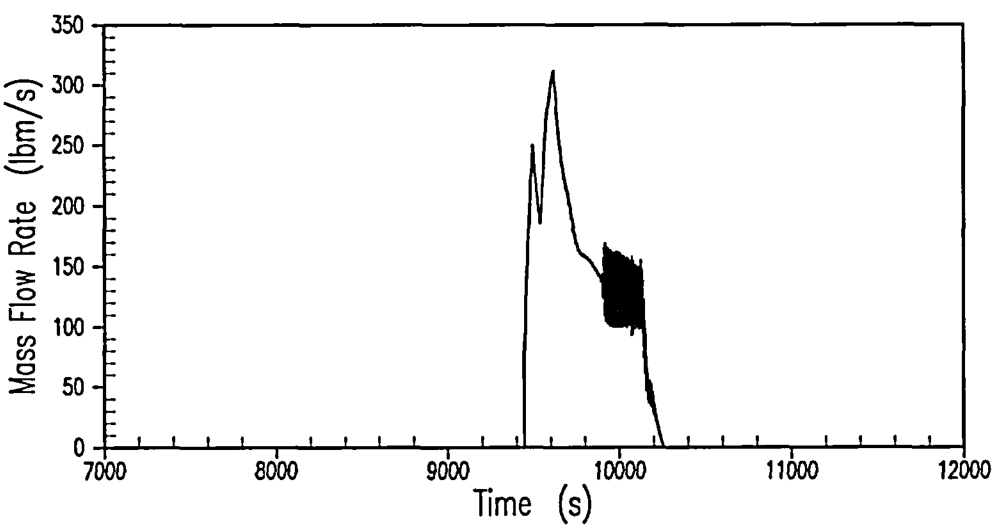


Figure 19E.4.8-16

ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-16



From DCD Revision 7, page 19E-68: **Current Figure 19E.4.8-17**

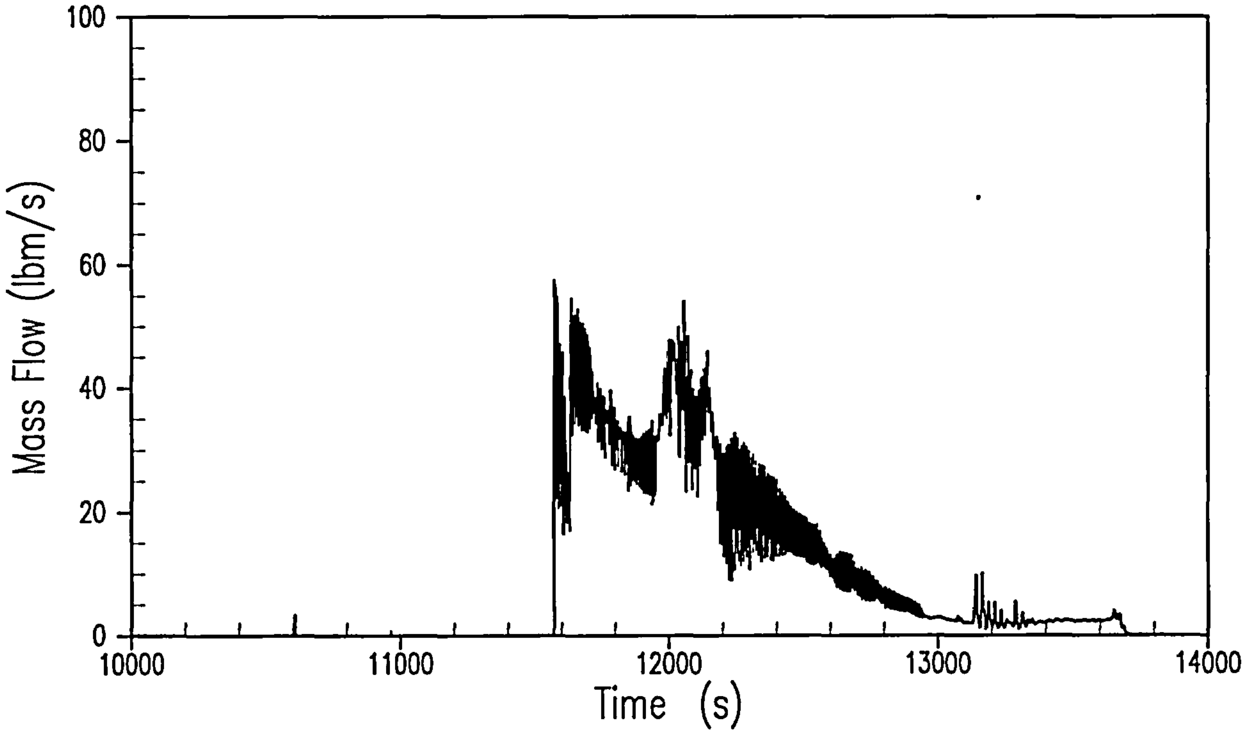
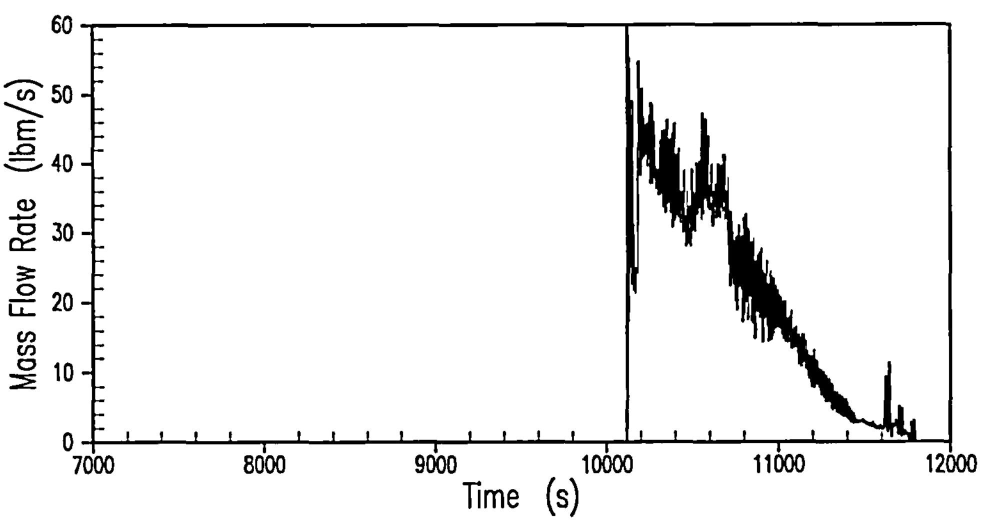


Figure 19E.4.8-17

ADS Stage 4 Vapor Flow, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-17



From DCD Revision 7, page 19E-69: **Current Figure 19E.4.8-18**

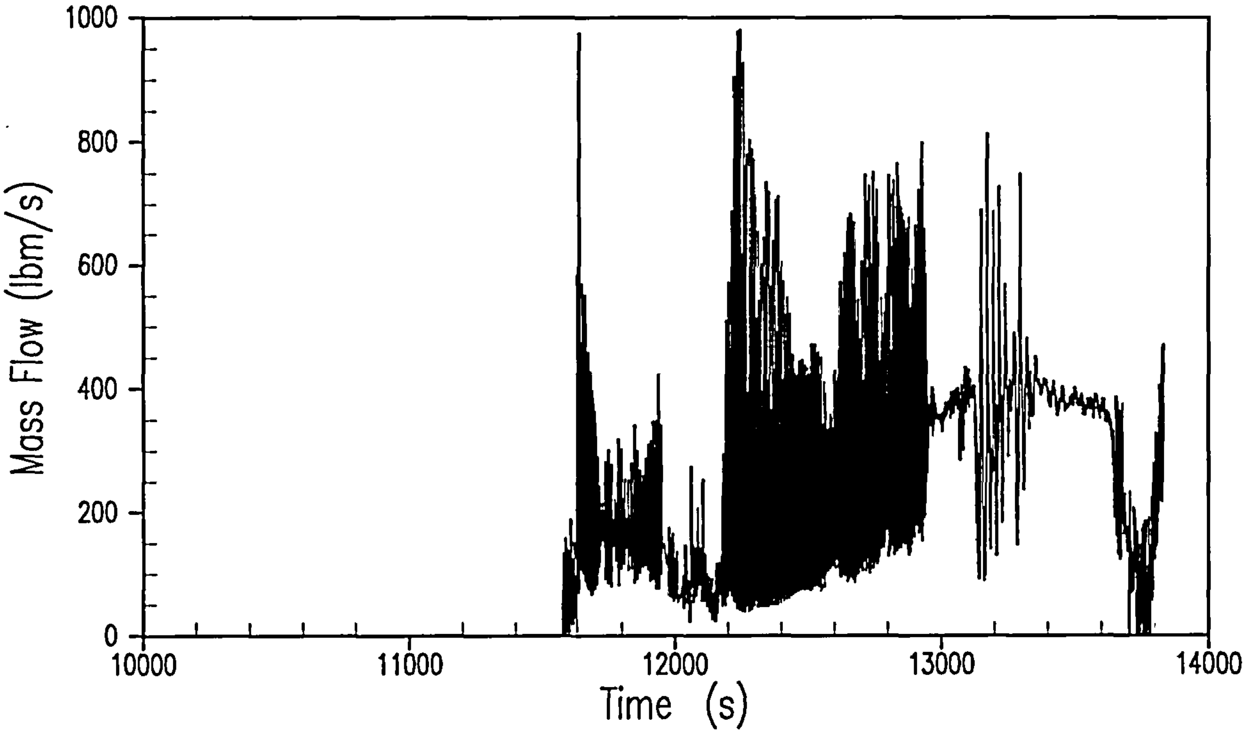
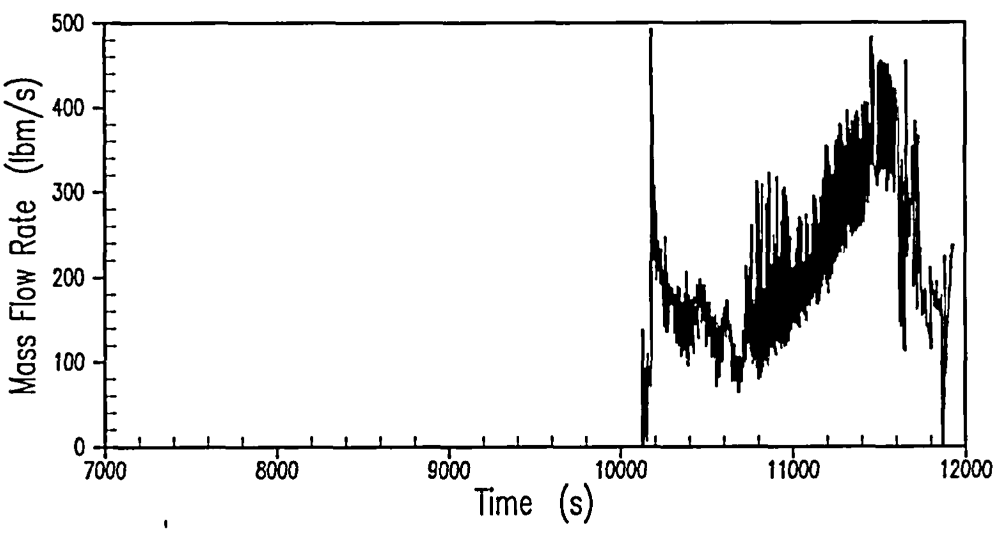


Figure 19E.4.8-18

ADS Stage 4 Liquid Flow, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-18



From DCD Revision 7, page 19E-70: **Current Figure 19E.4.8-19**

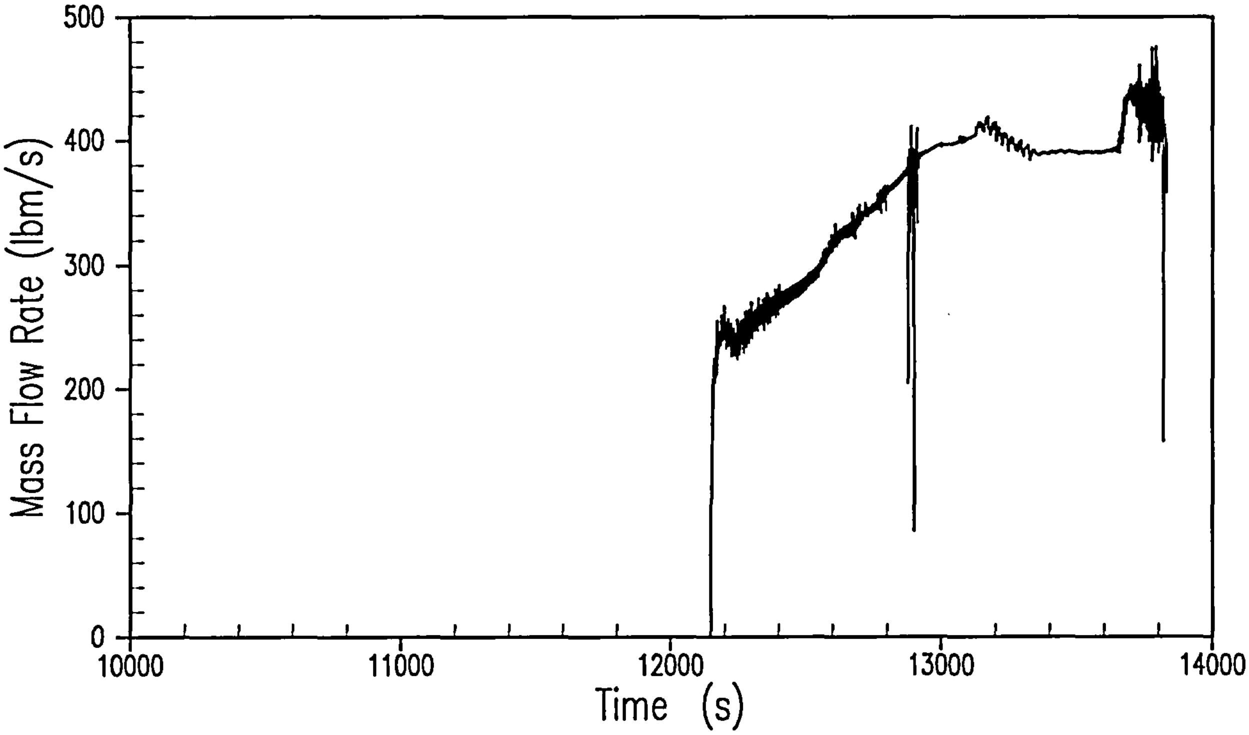
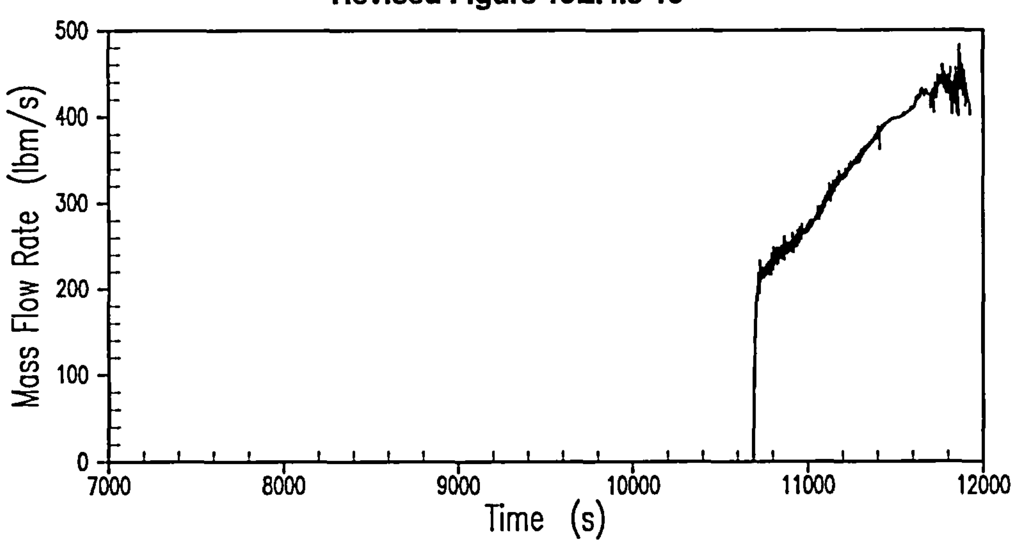


Figure 19E.4.8-19

Loop 1 IRWST Injection Flow, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-19



From DCD Revision 7, page 19E-71: **Current Figure 19E.4.8-20**

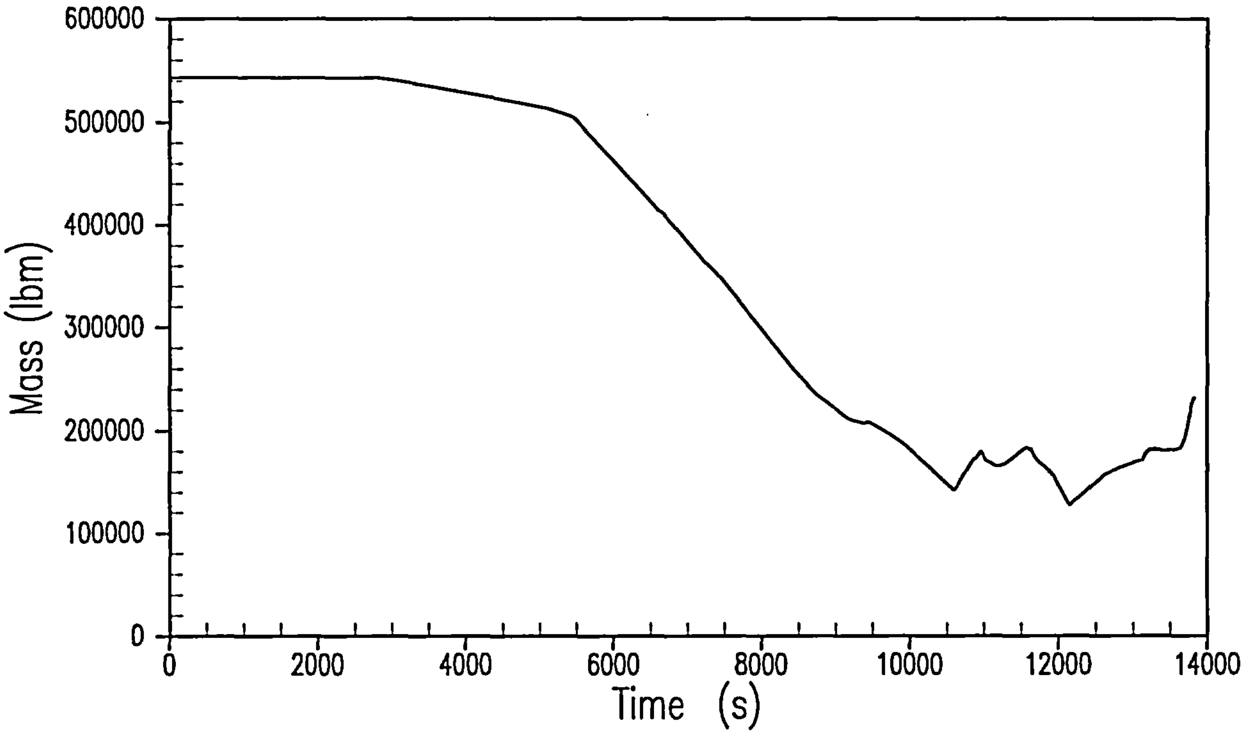
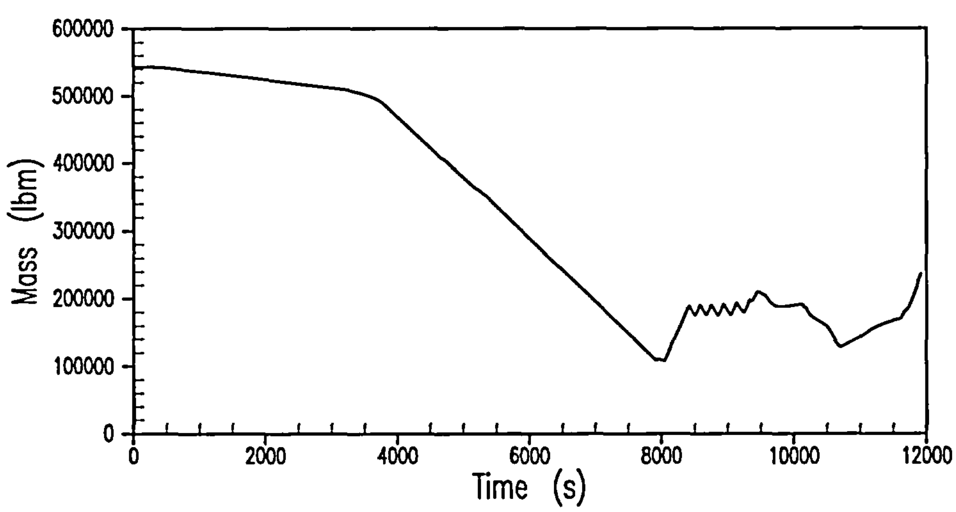


Figure 19E.4.8-20

Primary Mass Inventory, Loss of RNS in Mode 4 with RCS Intact

Revised Figure 19E.4.8-20



From DCD Revision 7, page 19E-72: **Current Figure 19E.4.8-21**

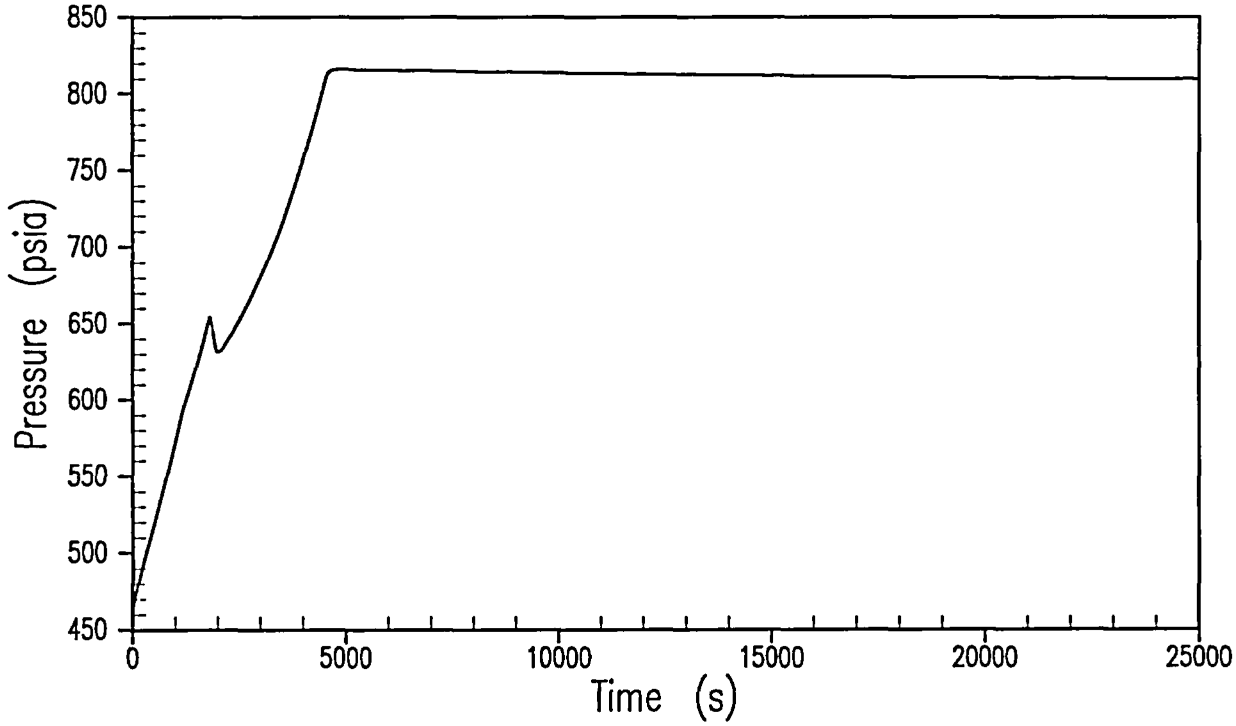
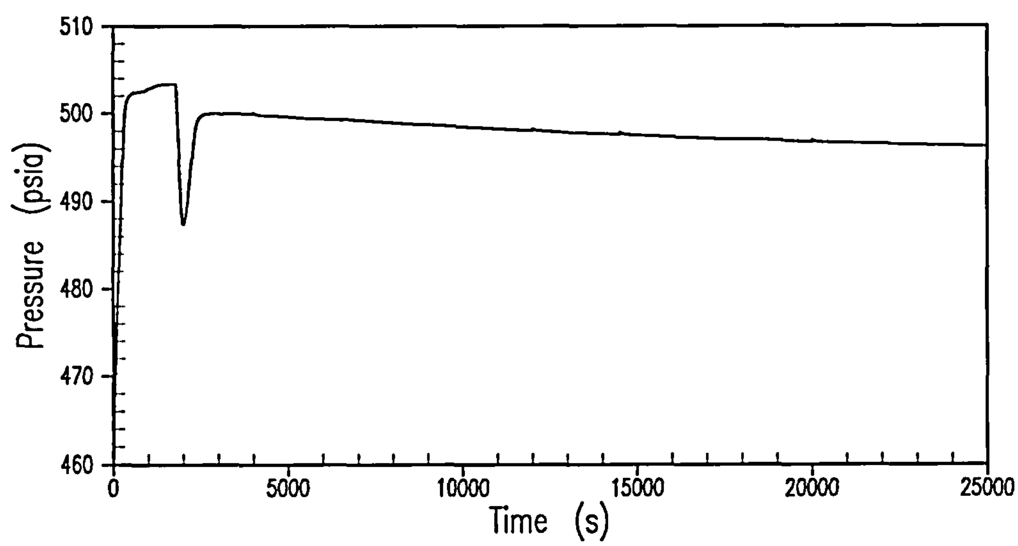


Figure 19E.4.8-21

Pressurizer Pressure, Loss of RNS in Mode 4 with RCS Intact, Manual Safety System Actuation at 1800 Seconds

Revised Figure 19E.4.8-21



From DCD Revision 7, page 19E-73: **Current Figure 19E.4.8-22**

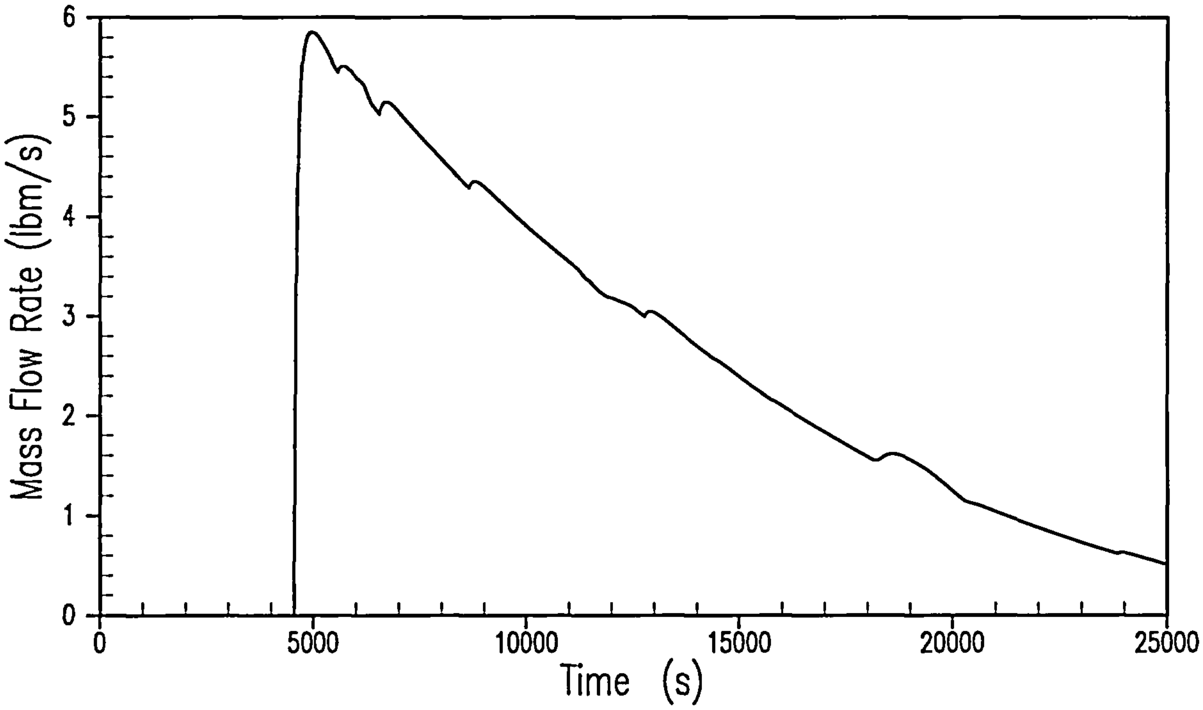
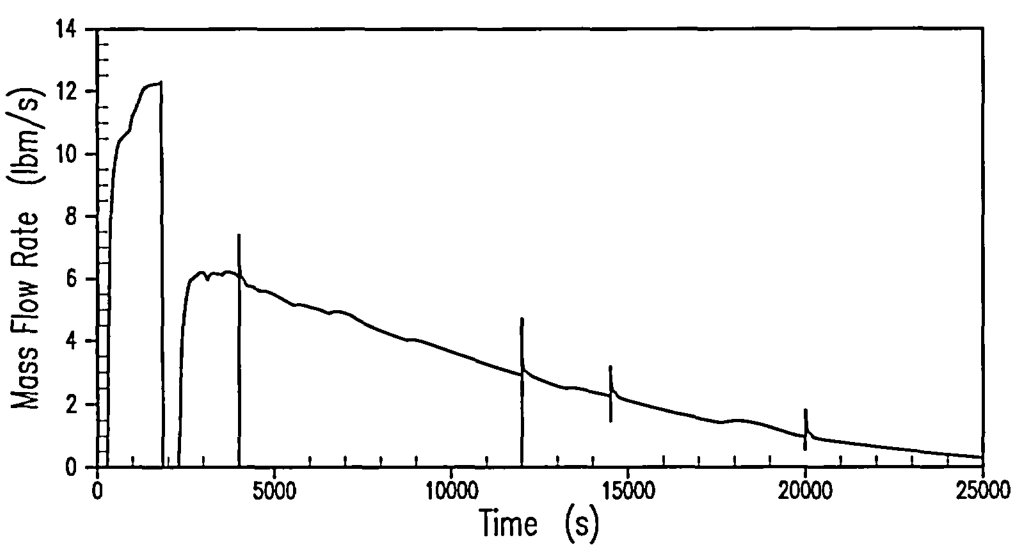


Figure 19E.4.8-22

RNS Safety Valve Flow, Loss of RNS in Mode 4 RCS Intact,
Manual Safety System Actuation at 1800 Seconds

Revised Figure 19E.4.8-22



From DCD Revision 7, page 19E-74: **Current Figure 19E.4.8-23**

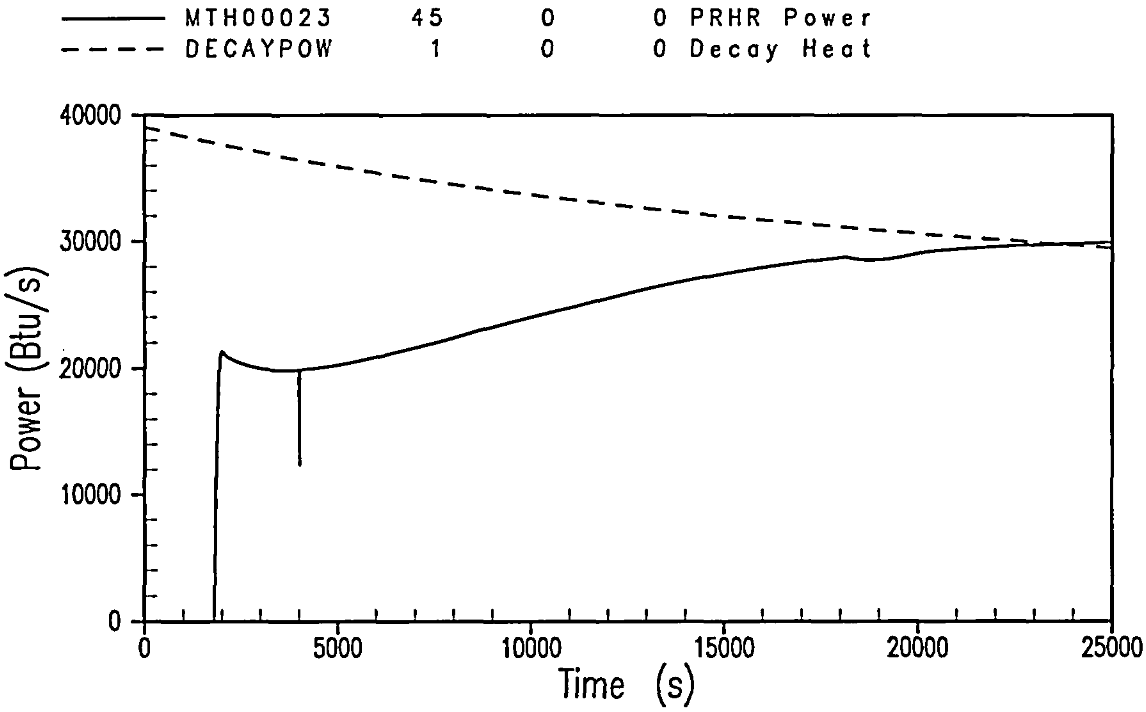
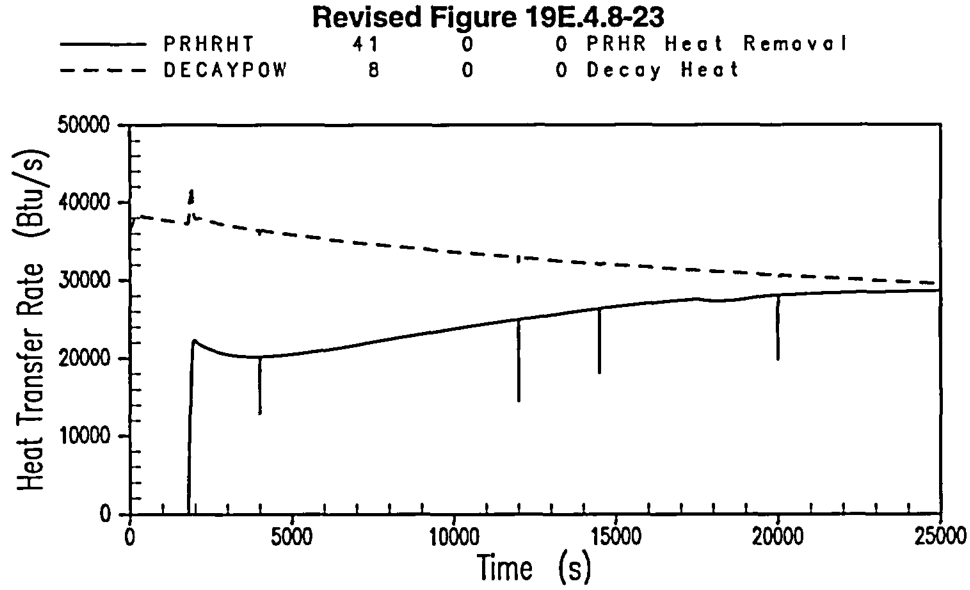


Figure 19E.4.8-23

Decay Heat and PRHR Heat Removal, Loss of RNS in Mode 4 with RCS Intact, Manual Safety System Actuation at 1800 Seconds

Revised Figure 19E.4.8-23



PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Draft Safety Evaluation Report Open Item Response

DSER Open Item Number: 15.3-1 Response Revision 1

Original RAI Number(s): 470.009, 470.011

Summary of Issue:

The staff has not completed its evaluation of the applicability of the AP600 aerosol removal coefficients to the AP1000 design. The staff will evaluate the impact of the differences in the AP1000 design as compared to the AP600 on the modeling of aerosol removal and will perform independent analyses of the estimated aerosol removal rates. Upon resolution of issues with the determination of aerosol removal rates in containment, as discussed in RAIs 470.009 and 470.011, the staff will complete its evaluation of the bounding accident sequence and the aerosol behavior and removal rates corresponding to the selected bounding accident sequence in the containment following a DBA. This is Open Item 15.3-1.

Westinghouse Response:

The Westinghouse responses to RAI 470.009 transmitted by Westinghouse letter DCP/NRC1535, November 26, 2002 and RAI 470.011 Rev. 1 transmitted by Westinghouse letter DCP/NRC1571, April 11, 2003 address previous NRC comments related to this issue.

NRC Additional Comments (Nov 6, 2003 telecon):

a) Clarify the use of shape factor described in section 15B.2.1.1 of the DCD.

b) Discuss the sensitivity of aerosol removal to aerosol void fraction identified in section 15B.4.2.3.

Westinghouse Response to NRC Additional Comments (Nov 6, 2003 telecon):

a) Section 15B.2.1.1 and 15B.3 of the DCD will be revised as shown below.

b) Section 15B.2.4.3 of the DCD will be revised as shown below.

Design Control Document (DCD) Revision:

15B.2.1.1 Sedimentation

Gravitational sedimentation is a major mechanism of aerosol removal in a containment. A standard model (Stokes equation with the Cunningham slip correction factor) for this process is used. The Stokes equation (Reference 2) is:

$$v_s = \frac{2\rho_p g r^2 \mathrm{Cn}}{9\mu}$$

where:

v_s	=	settling velocity of an aerosol particle
ρ_p	=	material density of the particle
g	=	gravitational acceleration
r	=	particle radius
μ	=	gas viscosity
Cn	=	Cunningham slip correction factor, a function of the Knudsen number (Kn) which is the gas molecular mean free path divided by the particle radius

However, the Stokes equation makes the simplifying assumption that the particles are spherical. The particles are expected to be non-spherical and it is conventional to address this by introducing a "dynamic shape factor" (Reference 2) in the denominator of the Stokes equation, such that the settling velocity for the non-spherical particle is the same as for a spherical particle of equal volume. The value of the dynamic shape factor (ϕ) thus depends on the shape of the particle and, in general, must be experimentally determined.

The concept of dynamic shape factor can also be applied to a spherical particle consisting of two components, one of which has the density of the particle material while the other component has a different density (Reference 9). In this manner, the impact of the void fraction in the particle can be modeled. Thus, the revised Stokes equation is:

$$v_s = \frac{2\rho_p g r^2 \mathrm{Cn}}{9\mu\phi}$$

The derivation of ϕ follows:

The two-component particle is considered to have a density ρ_{av} and an effective radius of r_e. Assuming that the second component of the particle is the void volume and letting the void fraction be ε, then the average density of the particle is:

ρ_{av} = the average density of the particle = $\rho_p(1-\varepsilon) + \rho_v\varepsilon$

where:

ρ_v = density of the void material (0.0 for gas filled, 1.0 for water filled)
ε = void fraction
ρ_p = material density (solid particle with no voids)

The definition of ϕ is obtained from the Stokes equation and the equation for mass of a sphere:

$$\frac{2\rho_p g r^2 Cn}{9\mu\phi} = \frac{2\rho_{av} g r_e^2 Cn}{9\mu} \quad \text{which reduces to:} \quad \rho_p r^2 = \phi\rho_{av} r_e^2$$

and: $$\frac{4\rho_p \pi r_0^3}{3} = \frac{4\rho_{av}\pi r_e^3}{3} \quad \text{which reduces to:} \quad \rho_p r_0^3 = \rho_{av} r_e^3$$

Then:

$$\phi = \frac{\rho_p r^2}{\rho_{av} r_e^2} \quad \text{and:} \quad r_e = r\left(\frac{\rho_{av}}{\rho_p}\right)^{-1/3}$$

From these two relationships, the dynamic shape factor is given by:

$$\phi = \left(\frac{\rho_{av}}{\rho_p}\right)^{-\frac{1}{3}}$$

15B.2.4.3 Aerosol Void Fraction

Review of scanning electron microscope photographs of deposited aerosol particles from actual core melt and fission product vaporization and aerosolization experiments (the Argonne STEP-4 test and the INEL Power Burst Facility SFD 1-4 test) indicates that the deposited particles are relatively dense, supporting a void fraction of 0.2.

The above-mentioned test results indicate that a void fraction of 0.2 is appropriate for modeling the aerosols resulting from a core melt. As part of the sensitivity study that was performed for the AP600 project, a case was run with a void fraction of 0.9. That analysis showed that the high void fraction resulted in an integrated release of aerosols over a 24-hour period that was less than 14% greater than that calculated when using the void fraction of 0.2. Thus, it is clear that the removal of aerosols from the containment atmosphere is not highly sensitive to the value selected for the void fraction. This is largely due to the fact that, while the selected value for void fraction has a significant impact on the calculated sedimentation removal, the impact on thermophoresis and diffusiophoresis removal is slight or none. The impact for AP1000 of using the higher value for void fraction would be less than was determined for the AP600 since sedimentation removal comprises a smaller fraction of the total removal calculated for the AP1000.

15B.3 References

1. NUREG-0800, Section 6.5.2, Revision 2, "Containment Spray as a Fission Product Cleanup System."

2. Fuchs, N. A., The Mechanics of Aerosols, Pergamon Press, Oxford, 1964.

3. Waldmann, L., and Schmitt, K. H., "Thermophoresis and Diffusiophoresis of Aerosols," Aerosol Science, C. N. Davies, ed., Academic Press, 1966.

4. Talbot, L., Chang, R. K., Schefer, R. W., and Willis, D. R., "Thermophoresis of Particles in a Heated Boundary Layer," J. Fluid Mech. 101, 737-758 (1980).

5. Rahn, F. J., "The LWR Aerosol Containment Experiments (LACE) Project," Summary Report, EPRI-NP-6094D, Electric Power Research Institute, Palo Alto, Nov. 1988.

6. Petti, D. A., Hobbins, R. R., and Hagrman, D. L., "The Composition of Aerosols Generated during a Severe Reactor Accident: Experimental Results from the Power Burst Facility Severe Fuel Damage Test 1-4," Nucl. Tech. 105, p.334 (1994).

7. MAAP4 - Modular Accident Analysis Program for LWR Power Plants, Computer Code Manual, May 1994.

8. Powers D. A., and Burson, S. B., "A Simplified Model of Aerosol Removal by Containment Sprays," NUREG/CR-5966, June 1993.

9. Powers, D.A., "Monte Carlo Uncertainty Analysis of Aerosol Behavior in the AP600 Reactor Containment under Conditions of a Specific Design-Basis Accident, Part 1," Technical Evaluation Report, Sandia National Laboratories, June 1995.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Draft Safety Evaluation Report Open Item Response

DSER Open Item Number: 17.3.2-2 Revision 1

Original RAI Number(s): None

Summary of Issue:

Implementation of QA Program for AP1000 Design

Westinghouse stated that a project-specific quality control plan was used to implement the requirements of the Westinghouse QMS program. The staff plans to conduct an inspection of the implementation of the project-specific quality plan to verify that design activities conducted for the AP1000 project complied with the Westinghouse QMS and the requirements of 10 CFR Part 50, Appendix B. As discussed in this report Chapter 20, "Generic Issues," the NRC staff will also address the implementation of QA requirements 10 CFR 50.34(f)(3) and NUREG-0933, Item I.F.2, during this inspection. This is DSER Open Item 17.3.2-2.

NRC Inspection Report:

NRC issued their inspection report 99900404/03-01 on November 4, 2003.

NRC Comments related to Section 3.3 of the inspection report:

1. Internal Westinghouse Quality Assurance (QA) audit Westinghouse-01-50, dated November 16, 2001, identified that the AP1000 project utilized outside design analysis from sources not on the Westinghouse qualified suppliers list. This issue was also identified in Westinghouse corrective action Issue Report (IR) 01-003480. The corrective action for IR 01-003480 included: (1) issuance of AP1000 project procedures to establish methods and processes for AP1000 supplier qualification, and (2) an update to the approved AP1000 suppliers list in accordance with these project procedures. A subsequent internal audit, dated November 22, 2002 (Westinghouse-02-20), reviewed the effectiveness of the IR 01-003480 corrective actions and determined that the implementation of these actions was effective. However, during the QA implementation inspection, the inspectors determined that Westinghouse lacked objective evidence demonstrating that AP1000 suppliers had been approved in accordance with AP1000 project procedures. Consequently, the inspectors concluded that the corrective actions of IR 01-003480 had not been effectively implemented. Further, the team concluded that internal audit Westinghouse-02-20 should have reasonably identified the lack of objective evidence supporting the qualification of AP1000 project suppliers. To assist the staff in determining if the internal audit and corrective action processes are capable of reliably identifying and correcting performance issues, please provide the following information:

    a. Explain why the corrective actions of IR 01-003480 failed to ensure that AP1000 project suppliers were qualified in accordance with applicable project procedures. Additionally, provide an explanation for the failure of internal audit Westinghouse

02-20 to identify the lack of objective evidence supporting AP1000 project suppliers.

b. Describe corrective actions taken to address any identified performance issues associated with the implementation of corrective actions for IR 01-003480 and conduct of internal audit Westinghouse-02-20.

2. In reviewing internal audits and self-assessments associated with the AP1000 project, the NRC inspection team determined that the scope of these oversight reviews focused primarily on procedural adherence rather than the technical validity of design analyses and calculations. Although this issue was noted in internal audit Westinghouse-02-20 and IR 02-326-M004, the inspectors determined that actions intended to assess the technical validity of calculations were not fully implemented. For example, although audit Westinghouse-02-20 and IR 02-326-M004 recommended a technical review of approximately 20 calculation notes, the inspectors determined that the technical validity of only one calculation appeared to have been independently evaluated.

   a. In light of the limited scope of internal audit and self-assessment calculation technical validity reviews, please describe any methods and oversight activities utilized by Westinghouse to assess the effectiveness of the AP1000 design control measures, particularly those related to the technical validity of design products.

   b. In your response to Item a. above, describe any additional assessments or reviews that have been performed, including the scope of the these reviews.

Westinghouse Response (Revision 1):

Westinghouse will respond to the nonconformance notice of the inspection report separately. The following are responses to the NRC comments related to Section 3.3 of the inspection report.

1. The Westinghouse internal Quality Assurance audit 01-50 was an assessment of the AP1000 team's compliance with the AP1000 Project Operating Procedures. The AP1000 response indicated that it took actions necessary to be in compliance with the AP1000 procedures. The AP1000 procedures are consistent with 10CFR50, Appendix B. The scope of the internal Quality Assurance audit 01-50 did not include an assessment that the AP1000 procedures were in strict compliance with the then evolving Nuclear Plant Programs Level 2 Quality Assurance procedures.

   a. When the issue of supplier qualification was identified, some contributors to the AP1000 program were not on any qualified suppliers list. The closure of this finding was based on: (i) adding all contributors and potential contributors to the AP1000 approved suppliers list with the process outlined for AP1000 in its Level

3 procedures and (ii) verifying the quality of active contributors already supporting AP1000. Recognize that most active contributors started to support AP1000 before it was decided to prepare an AP1000 Design Certification application. The requirement to make 10CFR 50, Appendix B applicable to their efforts came after they had already started work. The AP1000 contributors were qualified in accordance with the AP1000 Level 3 supplier qualification procedure including the quarterly reports that provide the only required objective evidence of their qualification. The Level 2 procedure describes how Westinghouse keeps their Qualified Suppliers List, not how AP1000 maintains their list of suppliers (AP1000 chose to use a graded quality approach). Using standard audit techniques, the subsequent Internal Audit chose to limit the scope of the audit by evaluating in detail the supplier(s) that performed Reactor Coolant Pump (RCP) work. The supplier selected was Curtiss-Wright Electro-Mechanical Division (EMD), which happened to be on the Westinghouse QSL. The corrective actions of IR 01-003480 did not assess whether all project contributors were qualified in accordance with Westinghouse Level 2 procedures because the supplier chosen for review was qualified in accordance with both the Westinghouse Level 2 requirements and the AP1000 Level 3 procedures. In addition, the AP1000 Level 3 procedures only require objective evidence of supplier evaluations by quarterly reports. The audit verified that the quarterly reports were issued as required. In retrospect, it is now seen that the AP1000 Level 3 procedures do not wholly conform to the Westinghouse Level 2 requirements. The AP1000 program is revising its Level 3 procedures to require listing of safety related contributors in accordance with the Westinghouse Level 2 procedures.

b. The AP1000 team is now evaluating all current suppliers working on safety related work on the AP1000 Project in accordance with the Level 2 procedures. Since the previous supplier audits were conducted appropriately to Level 3 procedures, no specific actions have been taken to correct the conduct of audits. The Project Quality Plan (PQP) addresses that the AP1000 approved suppliers list was controlled by the Level 3 Procedures. Going forward, all AP1000 safety related suppliers will be qualified to the Westinghouse Level 2 procedures. The AP1000 Level 3 supplier qualification procedure will be revised to reflect this change. A verification of the corrective actions in the AP1000 response to this NRC audit will be included in the current year Internal Audit scheduled for December 16-19, 2003. In addition, an "issue" has been opened in the Westinghouse Corrective Action Program (CAPs) that addresses examining the scope of audits to ensure they have the appropriate breadth and focus.

2. The issue noted in internal audit 02-20 and IR-02-326-M004 was properly classified as a "Watch / Trend" recommendation. For "Watch / Trend" recommendations, follow-up is administered by the audited department and discussed with QA during the next audit (which is scheduled for December 16-19, 2003). It was not considered a finding and did not cite a violation of any procedure; it was rather a suggestion from the auditor to the audited department of an item that has been found to be beneficial to other departments. The recommended action was developed by the auditor without explicit concurrence from the

project and was not based upon a documented sampling scheme or other set of requirements.

By procedure, all formal calculations are signed by their author, a verifier, and the responsible manager. The responsible manager's signature indicates that the author and verifier were competent for the subject matter of the calculation and that verification was independent. The auditor did not find any noncompliances with this procedure.

The AP1000 department chose to limit the scope of this self-assessment to calculation notes assigned by a manager in the AP1000 department and either authored or verified by an engineer in the AP1000 department. This limitation is appropriate, since other departments are audited independently of AP1000.

The AP1000 department further chose to limit this review to a single technical reviewer, and after reviewing the list of more than 20 available calculation notes he selected six which were within his area of technical expertise for more detailed consideration.

The technical reviewer examined these six calculation notes with the results as documented in letter WMS/APP0001 of July 18, 2003. For five of the documents, evidence of the scope of the verification (beyond the verifier's signature) was available either within the calculation note itself or in other files. For one calculation note such evidence was not found; in that instance the technical reviewer re-examined the calculation and satisfied himself that it was checked.

As a result of this self-assessment, the AP1000 department has revised our standard calculation note format in order to better capture the history of the verification process. This should address the auditor's concern for future AP1000 calculations.

Therefore:
a. and b. Westinghouse believes that the scope of the self-assessment was adequate and that no further action is required.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Draft Safety Evaluation Report Open Item Response

DSER Open Item Number: 19.1.10.1-2 Response Revision 2

Original RAI Number(s): 720.038

Summary of Issue:

PRA Input to Design Certification Process:

An important objective of the AP1000 design certification PRA is to identify important PRA insights and assumptions and make sure that they are addressed in the design certification through "design certification requirements," such as requirements for ITAAC, the requirement for a D-RAP and COL action items. These requirements will be incorporated in the DCD to ensure that any future plant which references the design will be built and operated in a manner that is consistent with important assumptions made in the design certification PRA.

In its response to RAI 720.038, the applicant provided a preliminary and, recently, a revised list of "design certification requirements." The staff expects the final list of "design certification requirements" to be in agreement with the resolution of all open items identified in the AP1000 DSER The staff is still reviewing the list of "design certification requirements" proposed by the applicant, especially in light of assumptions and insights related to differences in PRA models between the AP600 and API000 designs (e.g., differences in assumptions made in the fire risk analysis), The staff expects the applicant to continue providing requested information to ensure that all important assumptions made in the design certification PRA are appropriately included in the final list of design certification requirements. This is Open Item 19.1.10.1-2

Westinghouse Response:

The PRA insights and assumptions are addressed in the Section 19.59.10 PRA Input to Design Certification Process of the DCD Chapter 19 revision 3 and in the Section 59.10 PRA Input to Design Certification Process of the PRA Chapter 59 revision 1.

Westinghouse believes that the important assumptions made in the design certification PRA are included in the final list of design certification requirements.

NRC Follow Comment (Response Revision 1):

Westinghouse should address the following items in PRA Table 59-18:
- Response to OI 19.1.10.1-1
- Response to OI 19.1.10.1-6
- ADS-4 design features to address spurious actuation
- Fire risk insights
- NRHR insight regarding shutdown fire spurious opening of valve V024.

Westinghouse Response (Response Revision 1):

Items 79 and 80 will be added to PRA Table 59-18 as shown below to capture the OI 19.1.10.1-1 and 19.1.10.1-6 responses, respectively. Westinghouse believes existing Item 66 of Table 59-18 addresses ADS-4 design features regarding spurious actuation. Westinghouse believes existing Items 13,14,15,16,17,18,19,20,21,22,48,52,66,67,75 and new item 80 of Table 59-18 address fire risk insights. Westinghouse believes existing Item 67 of Table 59-18 addresses spurious opening of valve V024.

NRC Follow Comment (Response Revision 2):

Westinghouse should review the PRA insights and assumptions to ensure that any differences between the 'Eagle' and the 'Common Q' implementations for the Protection and Safety Monitoring System are properly addressed.

Westinghouse Response (Response Revision 2):

Westinghouse performed an additional review of the PRA insights and assumptions with a focus on the Protection and Safety Monitoring System and the differences between Eagle and Common Q. The PRA insights and assumptions were previously reviewed and modified from AP600 to address the differences between Eagle and Common Q. No changes to the insights and assumptions were identified by this additional review.

Design Control Document (DCD) Revision:

None

PRA Revision:

Sheet 24 of PRA Table 59-18 will be revised to add items 79 and 80 as shown below.

Table 59-18 (Sheet 24 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
79. Combined License applicants referencing the AP1000 certified design will provide resolution for generic open items and plant-specific action items resulting from NRC review of the I&C platform.	7.1.6

Table 59-18 (Sheet 24 of 24)

AP1000 PRA-BASED INSIGHTS

Insight	Disposition
80. The Combined License applicant will provide an analysis that demonstrates that operator actions which minimize the probability of the potential for spurious ADS actuation as a result of a fire can be accomplished within 30 minutes following detection of the fire and the procedure for the manual actuation of the valve to allow fire water to reach the automatic fire system in the containment maintenance floor.	9.5.1.8

AP1000 DESIGN CERTIFICATION REVIEW

Draft Safety Evaluation Report Open Item Response

DSER Open Item Number: 21.5-1 Item Code Comparison

Original RAI Number(s): 440.164

Summary of Issue:

In the October 2, 2003, NRC / Westinghouse meeting on AP1000 thermal/hydraulic open items Westinghouse committed to provide a discussion of the comparison between NOTRUMP and RELAP results for the AP1000 DEDVI break.

Westinghouse Response:

RELAP Modelling

The AP1000 RELAP input deck provided by NRC is a very detailed and complex input deck, consisting of more than 28,000 lines. The input deck used for the Small LOCA analyses is simplified with respect to a "Full Large LOCA" input deck that has been used as its basis. For example, the core active region has been simulated with a simple hydraulic pipe (11 nodes) and two different heat structures (simulating the average core and the hot rod) while the Full Large LOCA Model presents two half core regions connected in cross flow. The same simplification is made to the upper plenum region, while the quasi-two-dimensional arrangement is used for the Full Large LOCA Model.

The AP1000 RELAP core has been simulated as a vertical rod bundle with cross flow. The EPRI rod bundle interface friction model has been used in the core region.

The AP1000 RELAP model features a detailed quasi-two-dimensional downcomer model (8 pipes connected in cross flow through multiple junctions) while the NOTRUMP model is modelled as a three axial node lumped pipe.

RELAP vs NOTRUMP Comparison

Discussions with NRC indicated that RELAP is known to overpredict the drag forces between steam and liquid phases. Therefore, it was decided to investigate the impact of the rod bundle interphase slip correlation used in RELAP. To assess the effect of rod bundle interphase slip a RELAP case was run using the same input deck used by NRC and enabling the Bestion correlation via card 1 option 19. The results of this case are compared to the original NRC and NOTRUMP results.

Figure 1 provides the core collapsed liquid level comparison. This shows the effect of the interphase slip model in RELAP. Comparisons of the correlations to experimental tests are reported in Reference 1. In Reference 2 it is shown that the Bestion correlation predicts a lower interfacial drag than the EPRI correlation used in the base RELAP case, and hence more water is predicted in the rod bundle when the Bestion correlation is used. RELAP with the Bestion rod bundle correlation provides results that compare better to the NOTRUMP calculation.

NOTRUMP uses the Cunningham-Yeh void fraction model to represent interphase slip in the rod bundle and has been shown in Reference 3 to agree well with test data.

The deviation in predictions between 300 and 600 seconds results not only from the different rod bundle interphase slip models, but also from differences in downcomer modelling, break flow models, and initial accumulator pressure. During this time period there is blowdown through the broken DVI nozzle on one side of the downcomer with high rates of injection of subcooled accumulator water from the intact DVI nozzle on the other side of the downcomer. The AP1000 RELAP model has a detailed quasi-two-dimensional downcomer model (8 pipes connected in cross flow through multiple junctions) while in NOTRUMP the downcomer is modelled as a three axial node lumped pipe. The RELAP model uses a Henry-Fauske break flow model while NOTRUMP uses the Zaloudek/Moody break flow model. The RELAP model initial accumulator pressure is 651 psia while the NOTRUMP initial accumulator pressure is 715 psia. The net effect of these differences during this time period is that RELAP depressurizes more slowly, has a later ADS 1-3 actuation, has later and lower accumulator injection, and has less subcooling of the downcomer water feeding the core, as compared to NOTRUMP during this period. The lower injection and lower subcooling in RELAP result in lower core collapsed level during this period, as compared to NOTRUMP.

After 600 seconds the downcomer behavior is more one dimensional as the ADS4 flow paths become the dominant vent path rather than the DVI break and the injection rate is at the lower rate from the intact CMT and IRWST. After 600 seconds the NOTRUMP and RELAP Bestion core collapsed level predictions re-converge, while the RELAP EPRI prediction remains at a lower level. This difference in the long term is a result of the higher interfacial drag with the EPRI model, as noted above.

On the basis of the above comparison it is concluded that the differences between the NOTRUMP and RELAP calculation are explained by considerations related to different code modelling technique (downcomer model),computer code constitutive models (two phase drag forces and slip correlations, break flow models), and input differences (initial accumulator pressure). Both the NOTRUMP and RELAP analyses predict no core heatup.

Overall the NOTRUMP and RELAP analyses predict the AP1000 core is well protected. Initially the intact CMT provides injection, then phased ADS actuation provides depressurization and hot leg venting with injection from the intact CMT, accumulator and IRWST. NOTRUMP provides an acceptable method for AP1000 SBLOCA analysis as discussed in Reference 3.

REFERENCES

1. B. Schmitt (PNNL Battelle), "RBMK SB-2 Validation Results (KS-PH Rupture Simulation)"
2. P. Coddington, R. Macian, "A Study of the Performance of Void Fraction Correlations Used in the Context of Drift-Flux Two Phase Flow Models", Nuclear Engineering and Design, 215 (2002) [199-216],
3. WCAP-15644-P Rev 1, AP1000 Code Applicability Report, September 2003.

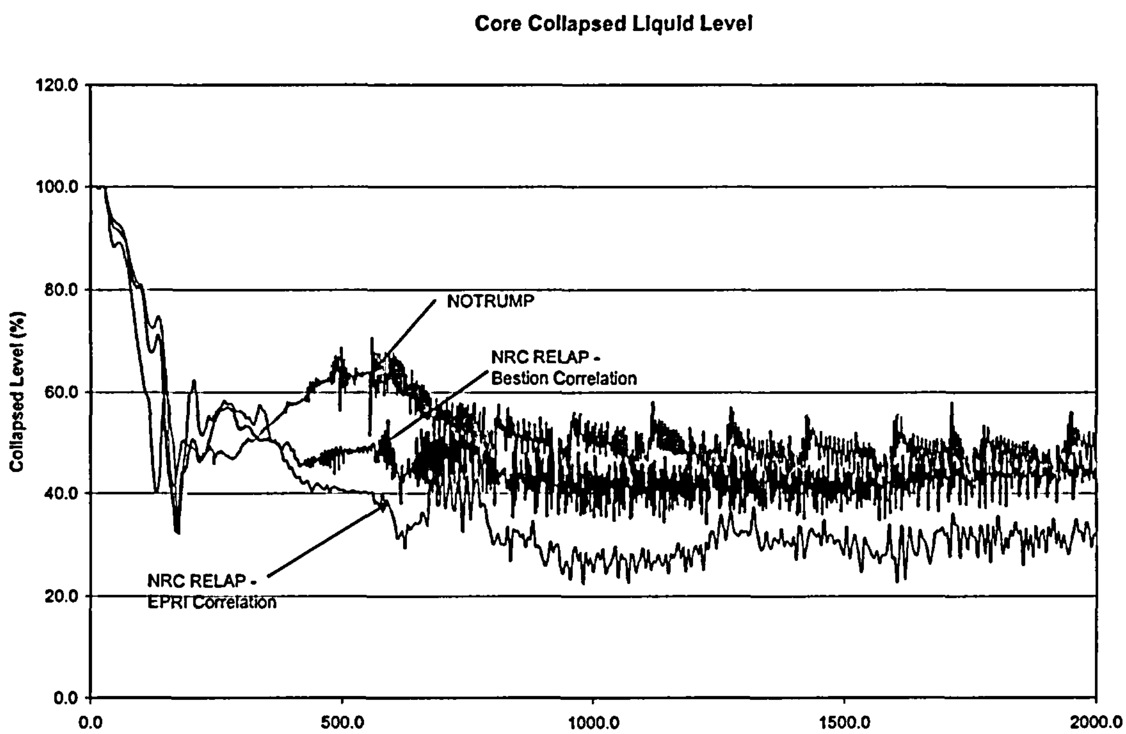


Figure 1 – Core Collapsed Liquid Level (%)

Design Control Document (DCD) Revision:

None

PRA Revision:

None