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TECHNICAL REPORT

TECHNICAL REPORT TR-5319-2

MARK I CONTAINMENT PROGRAM

PLANT UNIQUE ANALYSIS REPORT
OF THE
TORUS ATTACHED PIPING
FOR
VERMONT YANKEE NUCLEAR POWER PLANT

OCTOBER 3, 1983

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MARK 1 CONTAINMENT PROGRAM

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OF THE
TORUS ATTACHED PIPING

FOR

VERMONT YANKEE
NUCLEAR POWER STATION

SEPTEMBER 30, 1983

TELEDYNE ENGINEERING SERVICES

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ABSTRACT

The work summarized in this report was undertaken as part of the Mark 1 Containment Long Term Program. It includes the evaluation of all piping systems that are attached to the suppression pool (torus).

These piping systems include both Main Steam Safety Relief lines and piping attached to the torus shell.

Mark 1 induced loads, as well as original design loads, are included in the evaluation. Necessary modifications are summarized.

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1.0 GENERAL

The purpose of the Mark 1 Containment Program is to evaluate the effects of hydrodynamic loads resulting from a loss of coolant accident and/or an SRV discharge on the torus structure.

Teledyne report TR-5319-1 (Reference 1) reported the effects of Mark 1 loads on the Vermont Yankee torus structure, support system and internals. This second report completes the work on the program by considering the effects of the Mark 1 loads on the piping systems attached to the torus. Both the main steam relief lines and the piping connected to the torus shell are considered. Also included is the evaluation of piping penetrations, supports and active components.

A summary of modifications made as a result of this analysis is included.

The report is separated into two major categories, one that deals with main steam relief lines (SRV piping) and one that deals with piping attached to the torus shell (TAP). Each of these sections is written to stand alone and includes a discussion of methods and results.

2.0 SRV PIPING ANALYSIS

There are four main steam relief (SRV) lines at Vermont Yankee. These lines connect to the main steam lines in the drywell, extend down the main vents and penetrate the main vent into the torus (Figures 2-1 and 2-2). These lines penetrate the main vent pipe near the outer torus shell and enter the pool vertically; they then enter the discharge quencher at a 30^{0} angle (Figures 2-3 and 2-4).

Analysis results for the discharge end of the SRV lines were previously reported in Reference 1. This includes SRV piping in the torus airspace, the submerged part of the SRV line, the tee-quencher and the quencher support beam. This report will cover the remaining portion of the line, which includes:

- The main vent penetration.
- The SRV piping between the penetration and the main steam line.
- SRV pipe supports between the penetration and main steam lines.

The analysis of SRV piping in this report accounts for the fact that some modifications have previously been made to these lines. These modifications are described in the Reference 1 report and consist of the addition of tee-quenchers and support beams (Figure 2-4), and the addition of two ten-inch vacuum breakers on each SRV line.

2.1 Applicable Codes and Criteria

The SRV piping and pipe support analysis was performed in accordance with Section III of the ASME Code, 1977 Edition, including Summer 1977 Addenda (Reference 2).

In cases where modifications to SRV line supports were required, they were designed in accordance with Section III of the ASME Code (Reference 2).

Load combinations and stress levels were evaluated in accordance with Table 5-5 of the Mark 1 Containment Program Structural Acceptance Criteria Plant Unique Analysis Application Guide (Reference 5). Table 5-5 is reproduced in this report as Table 1.

2.2 SRV Loads

The Mark 1 Program defined several new SRV line conditions. These conditions resulted from different drywell and torus conditions and produced several different reflood heights and discharge pressures. The load cases considered are listed in Table 2-1.

The analysis and evaluation in this report considers all these SRV cases as well as seismic, weight, thermal and pressure effects.

The specific loads considered in this analysis include:

- Gas clearing (blowdown) loads.
- Water clearing discharge loads.
- Submerged structure drag on the SRV line, quencher and support due to pool motion.
- Thermal expansion of SRV line.
- Thermal expansion of containment structure.
- Seismic.
- Weight.
- Internal Pressure.

Calculational methods developed as a part of the Mark 1 generic program were used to the extent that they apply.

2.2.1 SRV Gas Clearing Loads

Sudden pressurization of the SRV line, due to rapid opening of the safety relief valve, causes unbalanced dynamic forces on the SRV piping. These forces progress through the system as pressure waves, whose speed and amplitude depend upon the particular line conditions being considered; the various SRV cases are listed in Table 2-1.

TES has evaluated the stresses resulting in various SRV piping systems, due to the cases listed in Table 2-1, and has concluded that SRV Case A1.2 is the bounding case for gas clearing loads. Case A1.2 is a first actuation after an SBA/IBA break and is characterized by increased gas density in the line before valve actuation. This increased density is a consequence of increased drywell pressure which affects the internal line pressure and density through the vacuum breakers. This increased density produces higher thrust forces than the lower density cases. This load case was run for each of the four SRV lines.

The calculation of loads resulting from Case A1.2, as well as all other SRV cases, was based upon use of the "Computer Code RVFOR-04" (Reference 7), which is the property of General Electric Company.

Case A1.2 was run for each of the four SRV lines at Vermont Yankee. Gas clearing loads associated with this case were used for all SRV cases and, therfore, produced conservative results for normal actuation, as well as other cases. In cases where this conservative condition exceeded the lower allowables associated with normal SRV actuation, Case A1.1 was also calculated.

2.2.2 SRV Water Clearing Loads

Water clearing loads are produced as water in the SRV line accelerates under line pressure and is forced around the elbows at the quencher end of the line. These forces are very sensitive to reflood height which varies for several of the second actuation cases.

Maximum line reflood and water clearing are clearly associated with SRV Case C3.3. Case C3.3 is the second actuation after an IBA/SBA break with steam in the drywell. The high reflood is a consequence of additional steam entering the line through the vacuum breaker after the first actuation (rather than air).

The high water clearing loads that result from this condition affect the torus end of the SRV line, including the piping in the main vent. It has a negligible effect on piping loads in the drywell.

Water clearing for Vermont Yankee was calculated for SRV Case C3.3, using G.E. programs RVRIZ and RVFOR-04. These programs were run for all four SRV lines and it was determined that line A would experience the highest reflood and water clearing loads. These worst-case water clearing loads for line A were used for all four SRV lines; the lines are identical inside the torus. The second valve actuation was assumed to occur at the point of maximum reflood.

Water clearing loads associated with SRV Case C3.3 bound all other cases and were used for all SRV analysis conditions.

2.2.3 Pool Drag Loads

The torus end of the SRV line, including the tee-quencher and quencher support beam, are submerged in the torus pool. These components are subject to drag loads due to pool motion from the following loads:

Pool Swell - Jet Loads
- Bubble Loads

Condensation Oscillation -
- Source induced drag
- Fluid Structure Interaction (FSI) Drag

Chugging - Source Induced Drag
- FSI Drag

SRV Discharge - Drag from Adjacent Quenchers (as applicable)

The drag loads associated with these events were calculated in the earlier part of the program and the methods are reported in Reference 1. At that time, the data was used to determine stresses in the SRV piping in the torus, the quencher and the support beam; these were all reported in Reference 1. The same drag load information was used as a part of this analysis work to help determine stress in the penetration and the SRV line and supports in the main vent pipe.

2.2.4 Thermal Expansion

Two different load conditions were considered for thermal expansion stress.

The first assumed that the entire SRV line was at its maximum operating temperature (350^{o}F). It included maximum thermal motion of the connection at the main steam line and assumed the drywell and torus were at ambient temperature.

The second case was like the first except the main vent pipe was assumed to be at 340^{o}F. This has the effect of moving the penetration in the main vent pipe relative to the torus and quencher.

2.2.5 Weight, Pressure and Seismic

Weight, pressure and seismic loads were also considered in the analysis. The seismic analysis duplicated the original seismic analysis for the plant, which was a static analysis. Results for the three directions of load were combined by SRSS.

OBE was taken as half of SSE, in accordance with the FSAR.

Seismic end effects were considered for this analysis, but judged to be negligible.

2.3 SRV Analysis Method

2.3.1 Piping Analysis

2.3.1.1 Computer Model

Analysis of all SRV load cases was performed using computer models of the piping systems and the STARDYNE computer code. A typical computer model is illustrated in Figure 2-5.

Features of the model include:

- Modeling of the main steam line with each SRV line.
- Representation of the stiffness of the main vent penetration by a set of six attachment springs, developed by computer analysis of the penetration area.
- Full representation of the tee-quencher and quencher support beam in the piping model.
- Full representation of the brackets between the quencher and support beam which allow free torsional rotation of the quencher arms.
- Two percent damping used for time history analysis.

2.3.1.2 Piping Analysis Method

Analysis for SRV discharge cases was done by imposing individual time histories for water and gas clearing loads at each bend and elbow in the system and performing the dynamic analysis. Bounding analysis was performed for these cases by combining gas clearing loads from SRV Case A1.2 with water clearing loads from SRV Case C3.3 into a single load condition. This conservative combination was used to bound all discharge cases, including normal actuations. Different line-unique loads were applied to each of the four SRV lines for gas clearing; water clearing is the same for all lines and is equal to the maximum load for the longest line.

Damping for these time history analyses was taken at 2% of critical and calculational time increments for the solution were taken at .0025 seconds. All response frequencies to 50 Hz were considered in the solution.

Seismic analysis was done using the same model and static analysis. Static accelerations were applied in the vertical and two horizontal directions and the results were combined by SRSS. OBE was taken as half these SSE values.

Analysis for thermal and weight conditions was done using static analysis. Calculations for internal pressure were done by hand.

2.3.2 Pipe Supports Analysis

Analysis for SRV piping supports was done using both hand and computer analysis. The STAAD computer program was used for the analysis of complex supports.

The support analysis included the attachment weld to the supporting steel. In all cases, support loads on the supporting steel were considered and judged to be acceptable without further analysis.

In addition to the SRV line supports in the drywell, each line has one support in the wetwell (in addition to the quencher support. There are also a total of eight supports in the main vent pipes, two on each line. Analysis of these supports included a detailed evaluation of the stresses in the main vent wall, near the support. These stresses were calculated using a Bijlaard analysis (Reference 9) in combination with intensified free-shell stresses due to vent header loads. Free shell stresses were taken from work done in Reference 1 using the computer model illustrated in Figure 2-7 of this report (Figure 4-4 in Reference 1).

Support analysis was done to Section III, Subsection NF (Reference 2).

2.3.3 SRV Main Vent Penetration Analysis

The SRV line penetrations of the vent pipe are illustrated in Figure 2-3. Analysis of these penetrations was done using a Bijlaard analysis (Reference 9), to determine local penetration stresses due to SRV line loads. These local stresses were added to intensified free shell stresses which occur in the vent pipe due to vent header loads. These were calculated using the finite element model illustrated in Figure 2-6. Development of these free shell stresses and a description of the model are given in Reference 1, Section 4.

2.4 Evaluation and Results (SRV)

2.4.1 General

Combinations of the previous analysis cases were done to allow evaluation of the results in accordance with Table 1. This table lists a total of 27 different load combinations; of these, 13 include an SRV event.

This evaluation is concerned with piping and supports from the main steam line to the vent pipe penetration - evaluation of piping and supports inside the torus is reported in Reference 1. This separation is important to the selection of the controlling load combinations that follow.

The results of a conservative load case (described below) were evaluated against level B allowables, without use of increased allowables, as allowed in Table 1. Where this load combination produced unacceptable results, less conservative combinations were evaluated, as described below.

Thermal loads were considered differently for piping and supports as discussed below.

2.4.2 SRV Pipe Stresses

Initial evaluation of SRV pipe stress was done as described in Section 2.4.1 above; that is:

$$DW + \sqrt{(SSE)^2 + (Blowdown)^2} = 1.2\ S_h$$

In cases where this conservative condition could not be met, the following three cases were evaluated:

(1) $DW + \sqrt{(SSE)^2 + (Blowdown)^2} = 1.8\ S_h$

(2) $DW + OBE = 1.2\ S_h$

(3) $DW + Blowdown = 1.2\ S_h$

These three cases represent load combinations (15), (1) and (2) in Table 1, and are still conservative. No further reduction in conservatism was necessary to qualify the SRV piping.

Thermal expansion stresses were evaluated for piping as a separate load condition, using ASME Code Equation 10.

Results of SRV pipe stress evaluation are listed in Table 2-2.

2.4.3 SRV Pipe Supports

SRV pipe supports were evaluated in accordance with the ASME Code, Section III, Subsection NF (Reference 2).

A worst-case load condition was developed to include:

- The conservative A1.2/C3.3 blowdown case.
- SSE seismic.
- Worst case thermal load.
- Deadweight.

Seismic and blowdown were combined by SRSS and added to the other loads. Allowable stress for this condition was maintained below yield to assure that pipe stress would not be effected by support motion. This stress criteria is consistent with the Case 15 allowables from Table 1.

Results of pipe support analysis are listed in Table 2-3.

2.4.4 Support Steel for SRV Supports

Evaluation of drywell support steel for SRV supports was done in accordance with Subsection NF of the ASME Code, (Reference 2), as required.

Evaluation of local stress in the main vent pipe wall was done using the same method described for the SRV penetration except evaluation for the Nozzle Piping Transition, paragraph NE-3227.5 is not required. This evaluation was performed for all main vent supports.

Controlling stresses for the main vent pipe wall are:

PRIMARY STRESS

(Local Membrane Shell Stress Intensity)

	Controlling Load Case	Calculated Stress	Allowable Stress
Upper Support	Case 15 (Table 1)	11,635	28,900 ($1.5\ S_{mc}$)
Lower Support	Case 15	27,886	28,900

SECONDARY STRESS

(Primary and Secondary Stress Intensity)

Upper Support	Case 15	49,169	69,900
Lower Support	Case 15	62,931	69,900

2.4.5 SRV Penetration

Stresses in the main vent pipe penetration area were evaluated in accordance with subsection NE of The ASME code, using the following paragraphs:

NE-3221.2	Local Membrane Stress Intensity
NE-3221.3	Primary General or Local Membrane plus Primary Bending Stress Intensity
NE-3221.4	Primary plus Secondary Stress Intensity
NE-3221.5	Analysis for Cyclic Operation
NE-3227.5	Nozzle Piping Transition (for vertical lines only)

Fatigue evaluation of the penetration (paragraph NE-3221.5) showed that the maximum load could be cycled on the penetrations for at least 7500 cycles without exceeding code allowables. The major load component in this case is SRV Case C3.3, which can only occur for a few cycles (less than 50). Normal SRV actuations produce substantially less load for up to 4500 effective stress cycles (Reference 10). Since the 7500 cycles of maximum load bounds both of these by such a large margin and since no other significant loads are imposed on the line, the penetration was assumed acceptable for fatigue without further evaluation.

Controlling stresses in the SRV penetration follow:

PRIMARY STRESS
(Local Membrane Shell Stress Intensity)

Controlling Load Case	Calculated Stress	Allowable Stress
Case 15 (Table 1)	27,922	28,900 (1.5 S_{mc})

SECONDARY STRESS
(Primary plus Secondary Stress Intensity)

Case 15	37,380	69,900 (3.0 S_{mi})

2.4.6 Valves

Evaluation of the SRV valves was done on the basis of stresses in the adjacent piping for the combined load cases. Pipe stresses meeting level B criteria were considered adequate to insure proper operation of the device. (Reference 5, Section 5.5).

Results of the valve evaluation are listed in Table 2-4.

2.4.7 Fatigue Evaluation

Fatigue evaluation of SRV lines was undertaken as a generic Mark 1 Program effort, using bounding assumptions. This effort is described and reported in Reference 10, and concludes that fatigue will not be a problem for Mark 1 SRV lines; this includes the SRV lines at Vermont Yankee. No further plant-unique analysis is necessary.

Fatigue evaluation of the SRV penetration is discussed in Paragraph 2.4.5.

2.5 Summary of SRV Line Modifications

Modifications to the SRV lines at Vermont Yankee included the following changes:

- Installation of tee-quencher discharge devices and quencher supports on all four lines (Figure 2-4).
- Installation of two ten-inch vacuum breakers on each SRV line.
- Modification to supports in the drywell as listed in Table 2-3.

TABLE 2-1

SRV LOAD CASE/INITIAL CONDITIONS

	Design Initial Condition	Any One Valve	ADS* Valves	Multiple Valves
	1 NOC*., First Act.	A1.1		A3.1
A	2 SBA/IBA,* First Act.	A1.2	A2.2	A3.2
	3 DBA,* First Act.[1]	A1.3		
	1 NOC, Subsequent Act.			C3.1
C	2 SBA/IBA, Sub. Act. Air in SRV/DL			C3.2
	3 SBA/IBA, Sub. Act. Steam in SRV/DL			C3.3

(1) This actuation is assumed to occur coincidently with the pool swell event. Although SRV actuations can occur later in the DBA accident, the resulting air loading on the torus shell is negligible since the air and water initially in the line will be cleared as the drywell to wetwell ΔP increases during the DBA transient.

* ADS = Automatic Depressurization System

NOC = Normal Operating Condition

SBA = Small Break Accident

IBA = Intermediate Break Accident

DBA = Design Basis Accident

TABLE 2-2

VERMONT YANKEE

SRV PIPE STRESS

SRV Line	Max. Stress Location	Line Size & Sch. @ Max. Stress Pt.	Maximum Stress	Allowable Stress
A	Elbow	10" Sch. 40	17,233	18,000
B	Wetwell 2-Way Support	10" Sch. 40	16,659	18,000
C	Sweepolet	6" Sch. 160	17,720	18,000
D	Elbow	10" Sch. 40	17,690	18,000

TABLE 2-3

VERMONT YANKEE

SRV SUPPORT MODIFICATIONS

SRV Line	Support #	Node #	Type	Modification
A	SRV-H15	58	Spring	Reset Spring
	SRV-H14	78	Spring	Reset Spring
	SRV-H13	128	Spring	Reset Spring
	"A"	151	U-Bolt	Tube Steel Frame to Replace U-Bolts
	"B"	153	U-Bolt	Tube Steel Frame to Replace U-Bolts
B	SRV-H18	46	Spring	Remove
	SRV-H19	94	Spring	Reset Spring
	"A"	140	U-Bolt	Tube Steel Frame to Replace U-Bolts
	"B"	150	U-Bolt	Tube Steel Frame to Replace U-Bolts
C	SRV-H20	19	Spring	Remove
	SRV-H21	56	Spring	Reset Spring
	"A"	120	U-Bolt	Tube Steel Frame to Replace U-Bolts
	"B"	130	U-Bolt	Tube Steel Frame to Replace U-Bolts
D	SRV-H16	60	Y Rigid	Modify to Double-Acting
	SRV-H17	110	Y Spring	Reset Spring
	"A"	146	U-Bolt	Tube Steel Frame to Replace U-Bolts
	"B"	150	U-Bolt	Tube Steel Frame to Replace U-Bolts
A through D			Torus U-Bolt	Add Tube Steel for Lateral Load

TABLE 2-4

VERMONT YANKEE

SRV VALVE EVALUATION

Component Designation	Component Type	SRV System	Pipe Stress	Allowable Pipe Stress
RV2-71A	Relief Valve	10" SRV-15A	17,813	18,000
10" Vac. Brk.	Check Valve		4,273	
10" Vac. Brk.	Check Valve		4,187	
3" Vac. Brk.	Check Valve		567	
RV2-71B	Relief Valve	10" SRV-15B	12,916	
10" Vac. Brk.	Check Valve		5,643	
10" Vac. Brk	Check Valve		5,960	
3" Vac. Brk.	Check Valve		3,780	
RV2-71C	Relief Valve	10" SRV-15C	17,844	
10" Vac. Brk.	Check Valve		4,314	
10" Vac. Brk.	Check Valve		4,449	
3" Vac. Brk.	Check Valve		4,083	
RV2-71D	Relief Valve	10" SRV-15D	10,620	
10" Vac. Brk.	Check Valve		4,738	
10" Vac. Brk.	Check Valve		4,721	
3" Vac. Brk.	Check Valve		4,068	

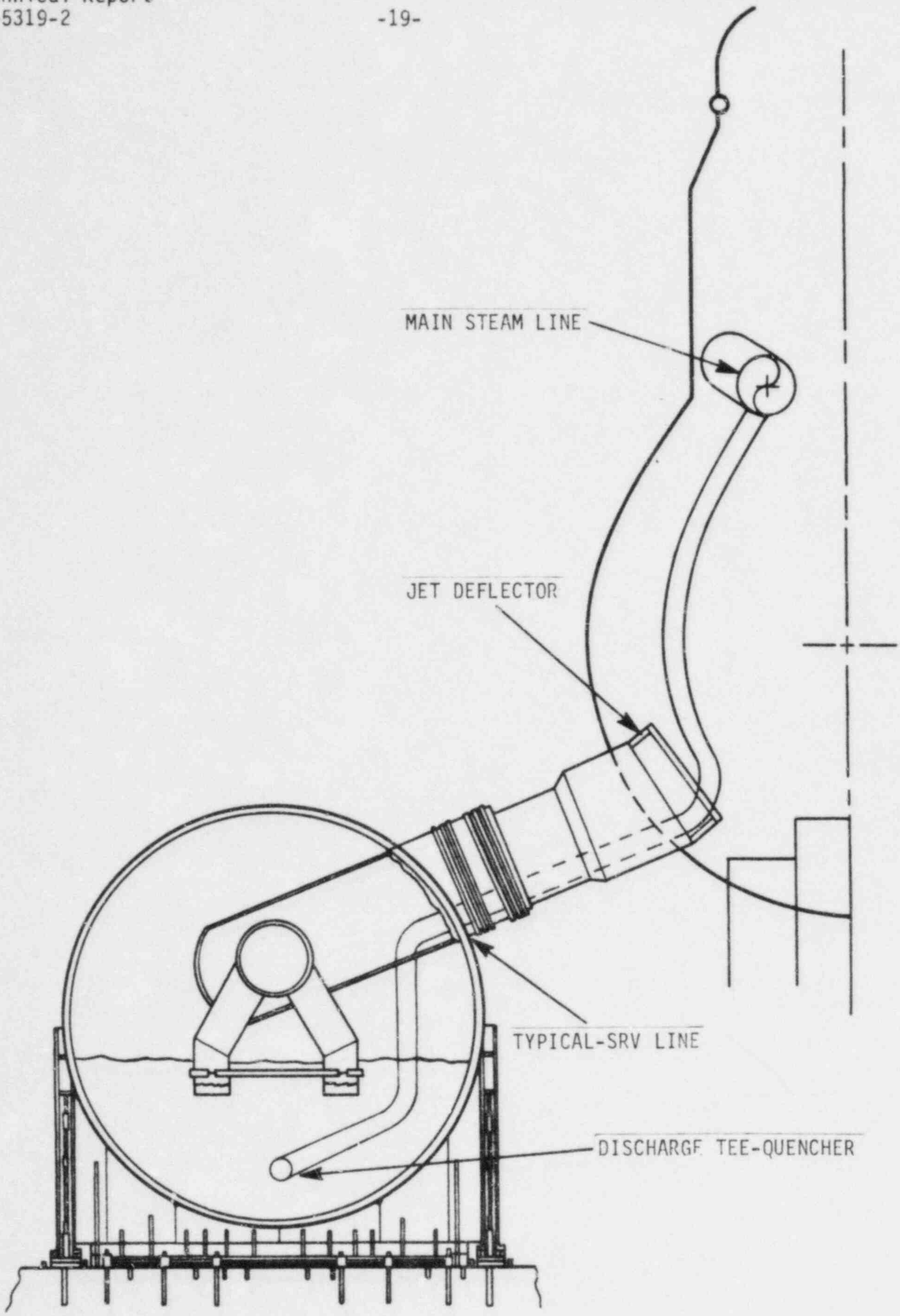


FIGURE 2-1 SRV LINE ROUTING-TYPICAL

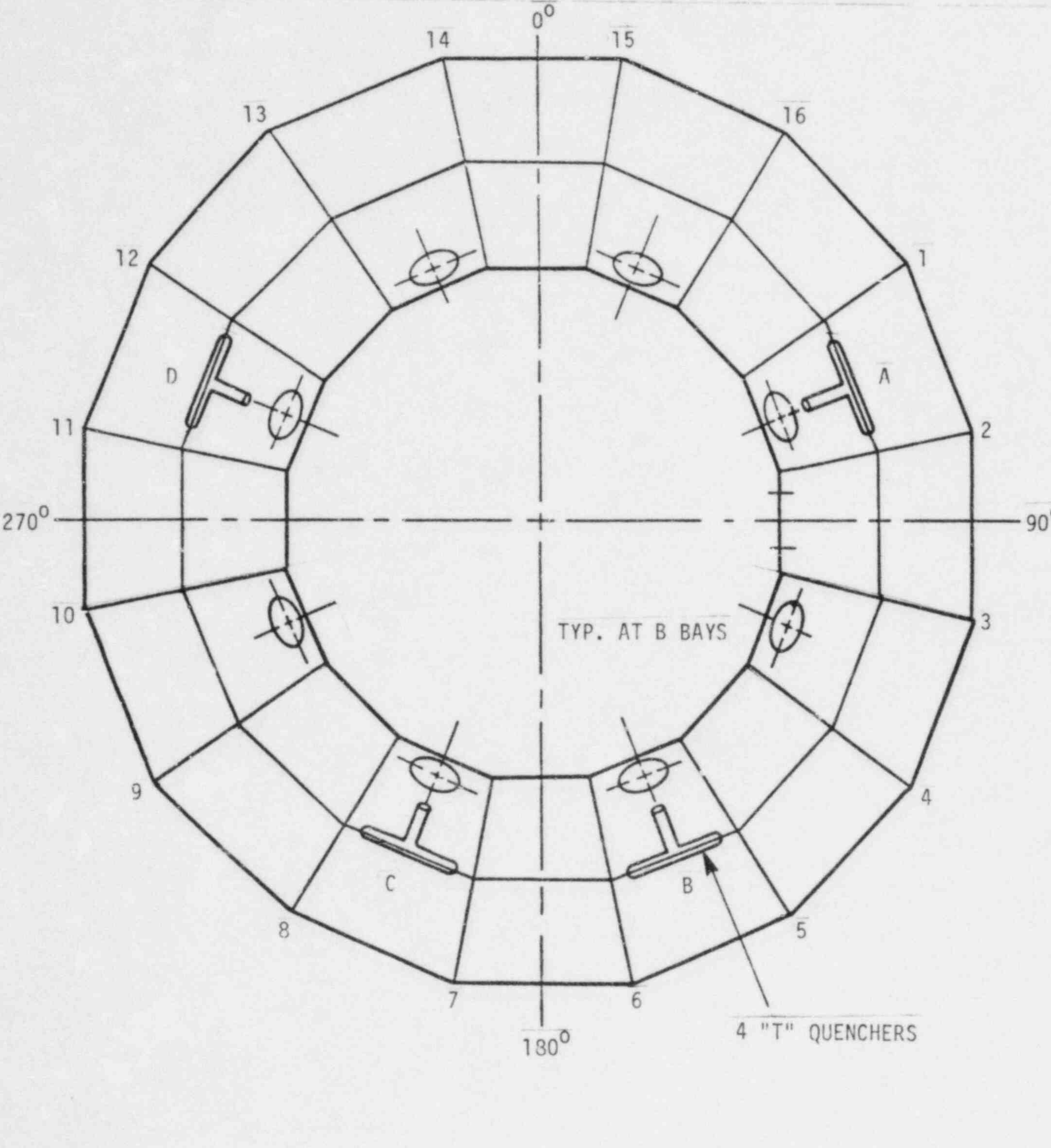
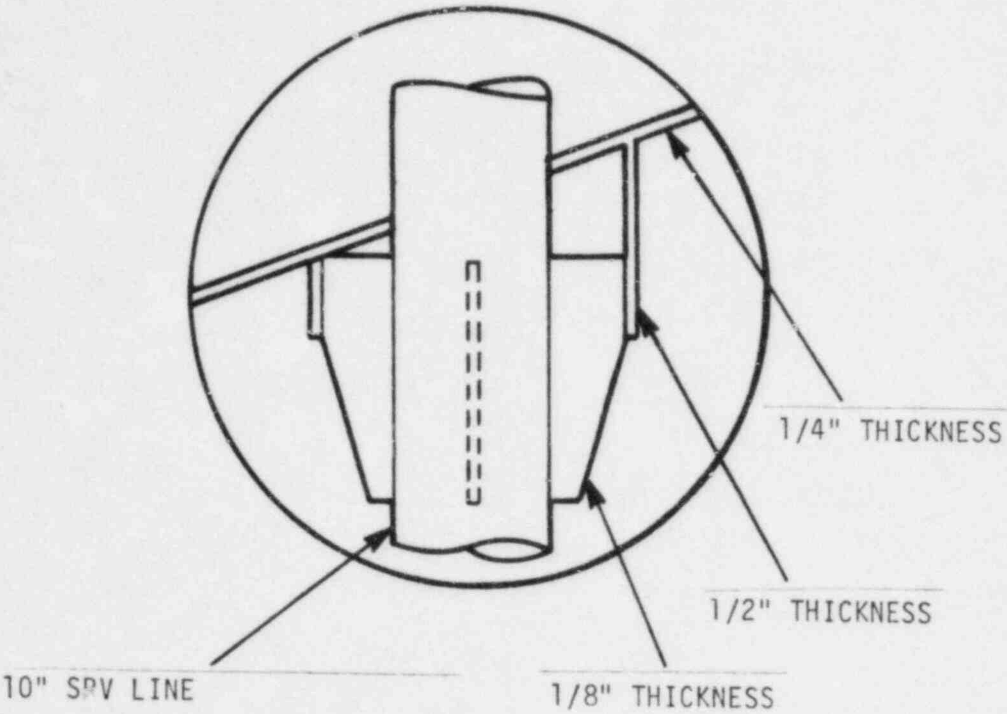


FIGURE 2-2 SRV LINE ARRANGEMENT-TORUS



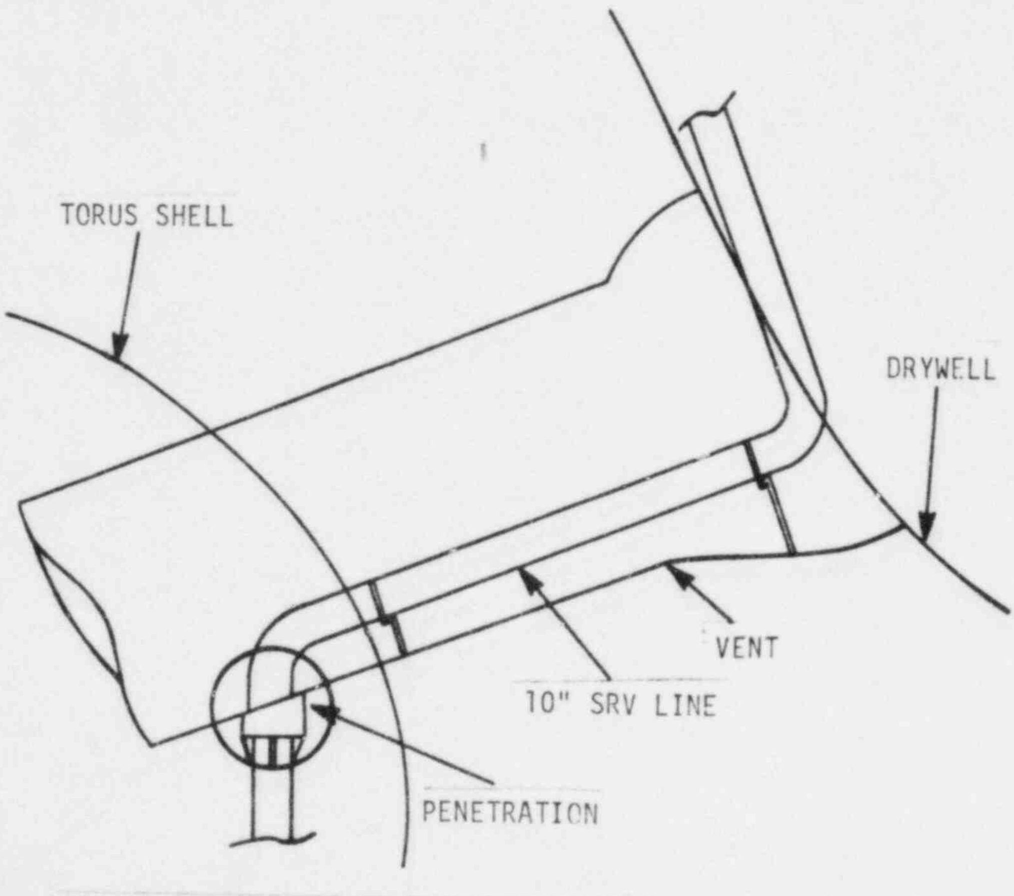


FIGURE 2-3 SRV LINE ROUTING, TYPICAL

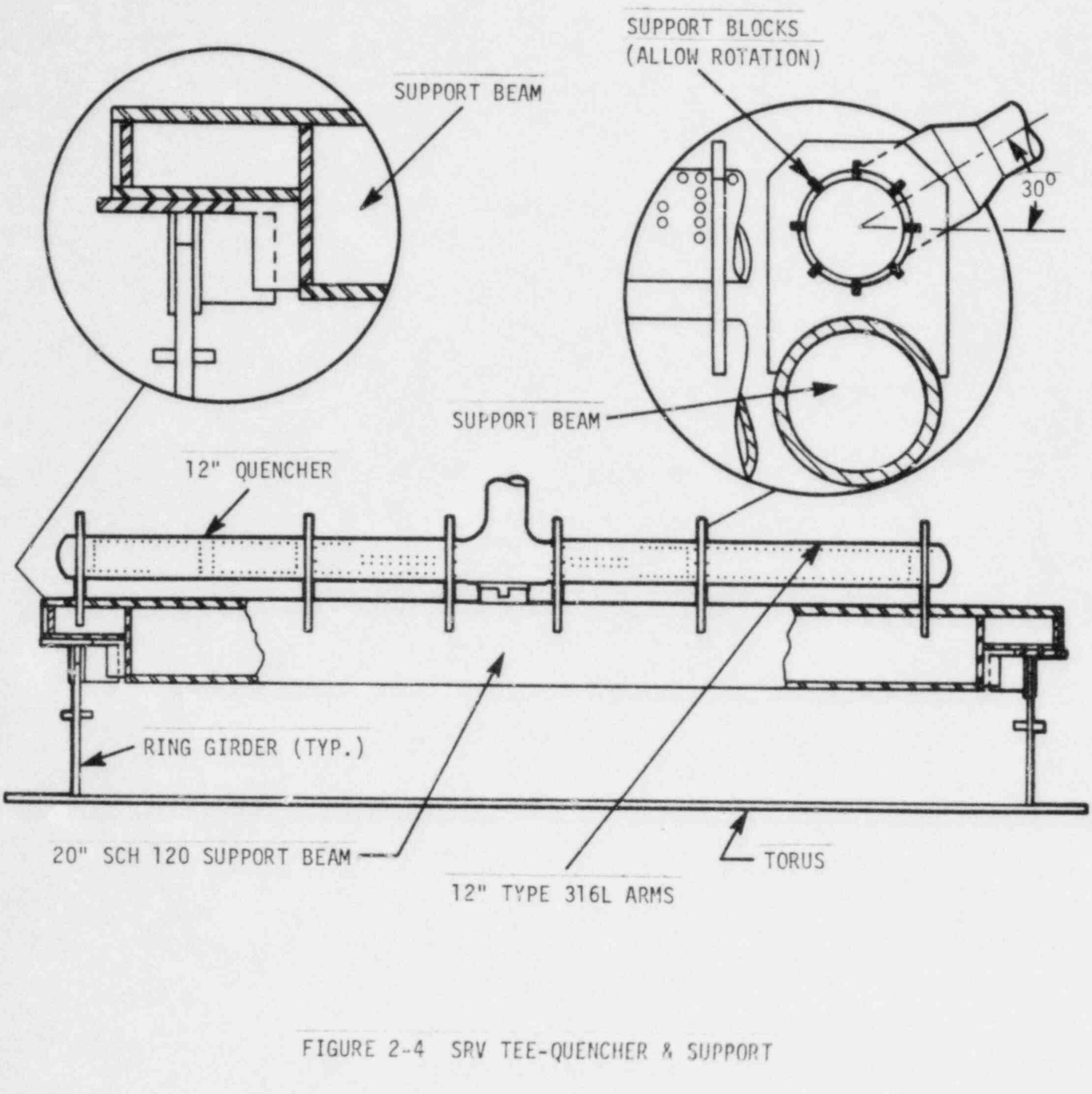


FIGURE 2-4 SRV TEE-QUENCHER & SUPPORT

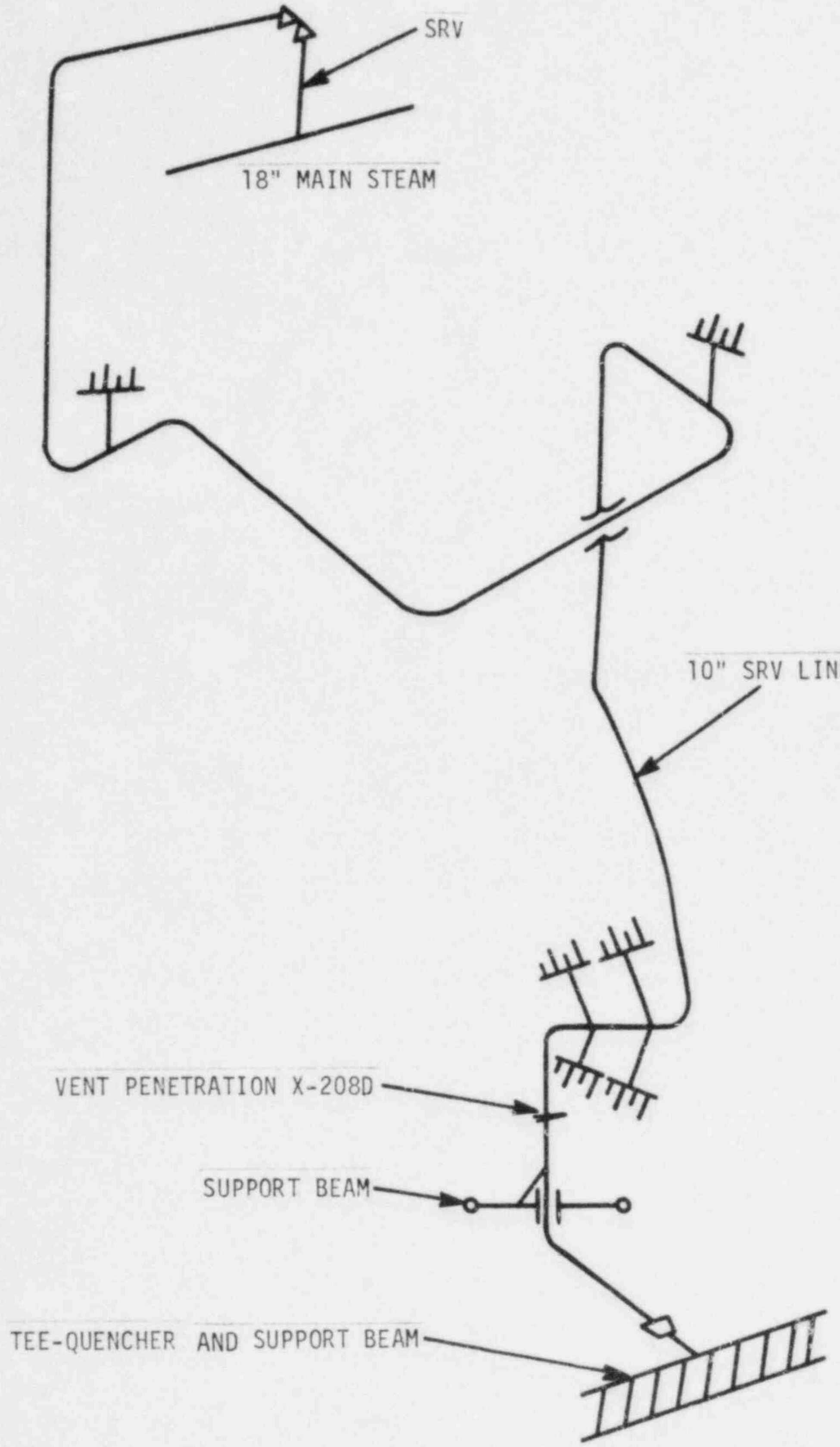


FIGURE 2-5 SRV PIPE MODEL,TYPICAL

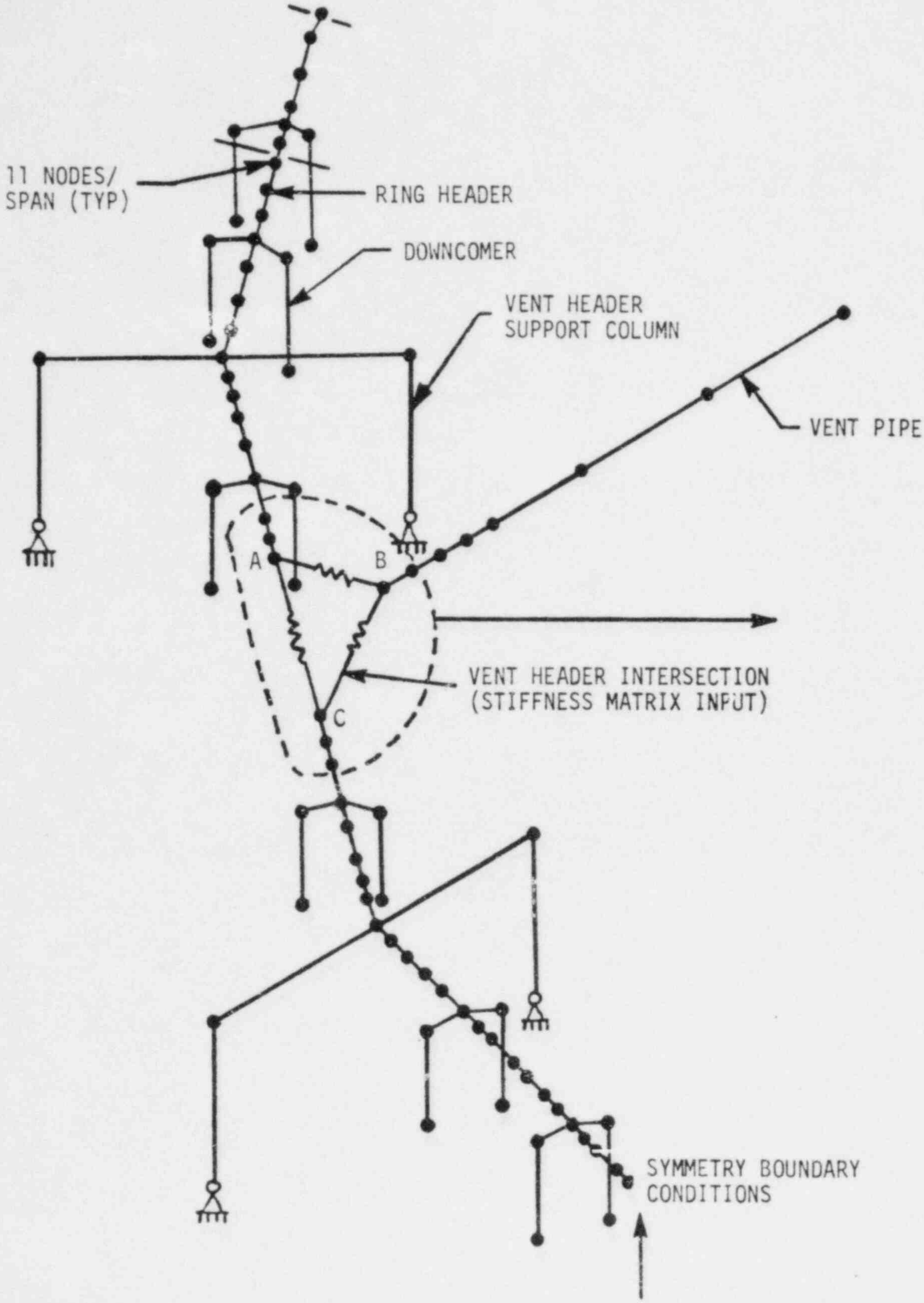


FIGURE 2-6 VENT SYSTEM MODEL

3.0 TORUS ATTACHED PIPING (TAP)

The torus at Vermont Yankee has 17 piping systems attached to its outer shell. These systems connect to 39 penetrations and are listed in Tables 3-1 and 3-2. Analysis of the large diameter attached piping systems included all piping from the torus to the first anchor. Small diameter piping was analyzed to the first anchor or a distance where the torus loads could be considered negligible.

Also considered in this analysis are:

- Branch piping connected to TAP systems.
- Torus penetration stresses.
- Piping inside the torus attached to TAP systems.
- Pump and valve loads.
- All pipe support and anchor loads.

The analysis method is different for large bore TAP systems (above four-inch diameter) and small bore systems (four-inch and below), as discussed in the following text.

Different organizations were involved in these analyses. TES performed the piping analysis of all piping systems connected directly to the torus, including branch lines with diameters greater than approximately 1/6 of the run lines. CYGNA* performed support analysis for all TAP and branch lines.

This report includes descriptions and results for all analysis.

3.1 Applicable Codes and Criteria

Analysis and modifications to TAP piping and supports were in accordance with the following codes:

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*CYGNA Energy Corp., Boston, Mass.

Piping Analysis

All TAP systems, including all branch lines with diameters greater than approximately 1/6 of run lines - ASME, Section III, 1977 (Reference 2).

Support Analysis

All TAP and branch supports - AISC-1978 Edition, and including NRC Bulletin 79-02 requirements (Reference 3). Allowable loads for SSE conditions were increased 33 percent, but did not exceed 0.9 Fy.

Load combinations and stress levels were evaluated in accordance with Table 5-5 of the Mark 1 Containment Program Structural Acceptance Criteria Plant Unique Analysis Application Guide (Reference 5). Table 5-5 is reproduced in this report as Table 1.

Damping of all time history piping analysis was taken at 2% of critical for all lines 12-inch diameter or less; larger lines used 3% damping. Seismic analysis used .5% damped spectra in accordance with the FSAR.

3.2 TAP Loads

Loads applied to TAP systems include:

Mark 1 Loads

- Shell motion due to pool swell.
- Shell motion due to SRV line discharge.
- Shell motion due to condensation oscillation.
- Shell motion due to chugging.
- Pool drag and impact loads on internal piping.

and

Original Design Loads

Deadweight.
Thermal expansion.
Seismic.

The Mark 1 loads, due to shell motion, were calculated based on plant unique shell response data developed during an earlier phase of this program and reported in the PUA report, Reference 1. Drag loads on internal piping were developed using generic methods from the Mark 1 Program as a part of this piping analysis work. These loads are described more fully in the Mark 1 Load Definition Report (Reference 11).

Analysis for seismic response was based on FSAR spectra.

3.2.1 Shell Motion Due to Pool Swell

TAP input loads, due to shell motion during pool swell, were based on data developed during the Plant Unique Analysis for the shell (Reference 1). The PUA shell analysis provided time history response information in five degrees of freedom for every point on the shell where large bore TAP was connected. This data consisted of three translations and two out of plane rotations (no torsion). Data for small bore piping was based on conservative bounding of the large bore data. Attachment points for large bore piping are illustrated in Figures 3-8a and 3-8b.

Data available from the plant unique shell analysis consists of time history displacements and rotations. These were converted to equivalent time history forces as described in paragraph 3.3.1.

A typical pool swell force time history is illustrated in Figure 3-1.

3.2.2 Shell Motion Due to DBA Condensation Oscillation

The DBA condensation oscillation load definition is given in Reference 11 as a set of spectral pressures, from 1-50 Hz. Shell response due to this loading was calculated by applying each frequency in this band to the torus shell model shown in Figure 3-7 and calculating response for each sinusoidal excitation. (This work was done earlier to allow calculation of shell stress for Reference 1). Shell response was calculated for frequencies up to 32 Hz; frequencies above 32 Hz were considered negligible as discussed in Appendix 2.

Shell responses for each of these frequency components were combined into an equivalent time history using random phasing of the individual components. Amplitudes of this equivalent time history were then increased by a factor of 1.15 to allow for the in-phase response of the four peak frequency components. See Reference 14 for a further discussion of the factor and component phasing.

This method of combining frequency components and generating an equivalent shell response time history was repeated for each TAP penetration for large bore piping. Responses for small bore piping were based on conservative bounding of the large bore data.

A typical DBA CO shell response is illustrated in Figure 3-2.

3.2.3 Shell Motion Due to Chugging

Shell response during chugging was defined separately for pre-chug and post chug loads.

Pre-chug is a sinusoidal pressure load equal to $\pm$ 2 psi on the torus shell; this load can occur at any frequency between 6.9 and 9.5 Hz

(Reference 11). Shell response for pre-chug was calculated by applying a continuous ± 2 psi sine pressure to the large torus model (Figure 3-7) in the specified frequency range. Maximum shell response in this range occurred at 9.5 Hz. This was considered as one of the inputs to TAP.

Post chug is specified as a spectrum of pressures from 1-50 Hz. Shell response was calculated for each 1 Hz component in this spectrum, then all 50 components were combined into an equivalent time history using random phasing of all components. Amplitudes of this time history loading were multiplied by 1.15 to account for the fact that some elements of the spectrum are not randomly phased. Further discussion of this factor can be found in Reference 6. The resulting pressure time history was applied to the model in Figure 3-7 to calculate shell response.

3.2.4 Shell Motion Due to SRV Line Discharge

TAP input loads, due to shell motion during SRV line discharge, were based on data developed for the PUA shell analysis (Reference 1). This shell analysis was the result of a finite element analysis that was calibrated with in-plant SRV test data, as described in Reference 1. The data resulting from the shell analysis were time histories and were used to provide time history input functions for the TAP.

Section 5.2 in the LDR (Reference 11) requires that we allow for a ± 25 percent shift in the SRV frequency for discharge through a cold line, and a ± 40 percent shift for discharge through a hot line. This was considered by examining the response modes and frequencies of the TAP piping systems and then making adjustments within the specified ranges to force worst case input-response frequency pairing.

The strongest torus shell response during SRV actuation is the result of simultaneous actuation of several SRV lines. These cases were considered by adding the shell pressures due to the individual actuations by absolute summation.

A typical shell response due to SRV actuation is illustrated in Figure 3-3.

3.2.5 Loads on Internal Piping

Most of the large TAP systems extend into the torus. In the case of suction lines, the internal portions usually consist of a pipe fitting and strainer. For return lines, longer sections of pipe, up to approximately 20 feet, extend into the torus.

The internal portions of these systems are subjected to submerged structure drag if they are in the pool; or pool impact, if they are above the water level. In either case, the appropriate Mark 1 loads were calculated and considered during the piping evaluation.

Loads for piping in the pool and above the pool were calculated in accordance with the methods of the Load Definition Report (Reference 11), NUREG 0661 (Reference 12) and Appendix 1 of Reference 1. All loads were considered, including:

For Submerged Piping:

- CO Source and FSI Drag.
- Post Chug Source and FSI Drag.
- Pre-chug Drag.
- SRV Bubble and Jet Loads.
- Pool Swell Bubble Drag.
- Pool Swell Fallback.

For Structures Above the Pool:

- Pool Swell Water Impact and Drag.
- Froth.
- Fallback.

A typical submerged structure load spectrum is shown in Figure 3-4. This spectrum includes CO and CH source and FSI drag.

3.2.6 Deadweight, Thermal and Seismic Analysis

Analysis for all TAP systems was also done for deadweight, thermal and seismic conditions.

Thermal analysis was performed at the original design thermal conditions. Thermal displacement of the penetration was determined from the maximum operating temperature of the torus and applied for all cases.

Seismic analysis was done using the OBE spectra from the FSAR. A typical horizontal spectra is shown in Figure 3-5. Analysis for SSE was taken as twice the OBE results. Total seismic stress was taken as the SRSS combination of the two horizontal and the vertical response, in accordance with the FSAR. The effect of the seismic response of the torus, at the penetration, was studied to determine if it would exceed the enveloped building spectra being used for the rest of the line. It was determined that the building spectra would control at all frequencies, so this same spectra was applied at the torus penetration.

3.3 TAP Analysis Methods

The method for TAP pipe stress analysis varied for each of the following cases:

- Large bore piping (over 4" diameter).
- Small bore piping systems (4" and less), which could be reduced to single degree-of-freedom approximations.
- Small bore piping which could not be reduced to single dof systems.
- Branch piping off of TAP systems.

Analysis of supports, anchors and torus penetrations did not vary and was the same for all types of piping systems.

3.3.1 Representation of Torus Shell for Piping Analysis

Because the larger TAP systems are stiff and heavy when compared to the torus shell, it is important that the piping computer model allows for dynamic interaction between the piping and the torus. This was done for all TAP piping systems by including a set of ground springs in the piping model to represent the torus connection, as illustrated in Figure 3-6. Five ground springs were used to represent the torus shell; these represented stiffnesses associated with the three translations of the shell and the two out of plane moments on the shell. Torsional pipe loads were considered negligible.

The stiffness values of the ground springs were calculated by applying unit loads and moments to the large shell finite element model of the torus illustrated in Figure 3-7.. Different attachment stiffnesses were calculated for each pipe penetration location, and then applied to the appropriate piping system model.

3.3.2 Piping Analysis Method - Large Bore Systems

Analysis of all large bore piping systems was done using finite element models of each system. These models included ground springs to represent the torus and also included piping inside the torus.

All analysis on these models was done using the STARDYNE computer code. Time history dynamic analysis used damping values of 2% of critical for all lines 12-inches and less, and 3% for larger lines. Seismic analysis utilized a ½% damped spectra. Analysis on these models included:

- Zero and Full ΔP Pool Swell Motion and Drag Loads.
- Post Chug Shell Motion and Drag Loads.

- DBA CO Shell Motion and Drag Loads.
- SRV Shell Motion and Drag Loads.
- Deadweight.
- Seismic.
- Thermal.

Pre-chug was considered as a separate load condition, but it was determined that it would always be bounded by DBA CO. On that basis, pre-chug loads were not run for each TAP system.

All TAP response due to shell motion was done using time history analysis. Response due to drag loads on internal piping was calculated by harmonic analysis for the spectral loads and hand analysis for transients. The effects of both shell motion and internal loadings were considered for all points in the piping system.

Pipe stress due to welded support attachments was considered by separate analysis and included in the pipe stress evaluation.

3.3.3 Piping Analysis Method - Complex Small Bore Systems

Analysis of small bore piping systems that could not be reduced to single degree of freedom systems were treated identically to large bore systems, except for the loads considered. For these systems, the loads considered included:

- DBA CO.
- Deadweight.
- Seismic.
- Thermal.

Consideration of Mark 1 dynamic loads was limited to DBA CO, based on experience with large bore piping analysis for five Mark 1 plants.

This experience showed that all high stressed lines were controlled by DBA CO, except in a few special cases. Appendix 1 discusses this furt'ər.

3.3.4 Piping Analysis Method - Simple Small Bore Systems

Small bore piping systems that could be reduced to single mass approximations were analyzed using hand analysis. Torus shell stiffness was included in these models to the extent that it affected first mode response, as a minimum. Higher modes were considered if they fell within the range of the input load. Typically, these systems consisted of a short length of pipe, terminating in a valve or tubing.

Shell input to these systems (for Mark 1 loads) was formatted in the frequency domain to provide an input spectrum. This spectral data was used in combination with the hand analysis to calculate response levels.

Loads considered for simple small bore systems were the same as for the more complex small bore systems, including seismic, weight and thermal, if applicable.

3.3.5 Piping Analysis Method - Branch Piping

Branch piping connected to TAP systems was modeled with the TAP systems if the ratio of their bending stiffness was greater than approximately 1:40.

Branch piping too flexible to meet this ratio was considered by separate evaluation per the PUAAG. These systems were analyzed statically, where required, by placing a displacement at the connection point, equal to the total TAP motion at the connection point. (except deadweight deflections, which were considered negligible).

3.3.6 Piping Analysis - Load Input for Computer Models

3.3.6.1 Mark 1 Loads Due to Shell Motion

Shell motion, due to internal Mark 1 loads, is due to pressures across broad areas of the shell, as opposed to concentrated forces at the penetration. Because of this, the interactive effects of piping and shell should include allowance for local shell compliance in the force input to the piping system. The method of load input for TAP accounts for this. The method is illustrated in Figure 3-6.

The steps involved are:

- Extract displacement time history from large computer model for a shell without an attached TAP system. (Reference 1 and Figure 3-7).
- Determine local shell stiffness from large computer model (Reference 1 and Figure 3-7).
- Determine an equivalent force time history at the penetration by multiplying displacement by stiffness.
- Apply the force time history to the TAP as shown in Figure 3-6.

The use of forces, rather than displacements to drive the model, is necessary to accurately account for the inertial interaction of the piping, since the available shell response data is for an unloaded shell (no piping). Use of forces as input will allow displacements at the penetration to increase or decrease in reaction to the inertial forces from the piping.

3.3.6.2 Submerged Drag Loads on Internal TAP

Drag loads on internal piping during CO, CH, SRV and pool swell were evaluated using the same TAP piping models that were used for shell induced, seismic and other loads. Internal drag loadings were run as separate cases, with worst-case orientations, and then combined with other loadings to determine pipe stress, support loads and penetration stress. The effects of drag load on both internal and external parts of the TAP system were calculated and included in all evaluations.

Loads were applied to the piping and evaluated by the following methods:

- Pool Swell Drag - Static Analysis x 2.
- Pool Swell Fallback - Static Analysis x 1.
- Pool Swell Impact - Static Analysis x 2.
- Pool Swell Froth - Static Analysis x 2.
- CO Drag - Dynamic Analysis (Spectrum).
- Post Chug Drag - Dynamic Analysis (Spectrum).
- SRV Drag - Static Analysis x 1.
- Pre-chug - Bounded by DBA CO.

Piping response to CO and post chug drag were evaluated using dynamic analysis. These spectra, including their FSI components, were then enveloped to form a single spectrum that was used in this analysis. Each frequency component in this spectrum was then applied to the CG of the submerged internal piping as a harmonic forcing function. The load in the pipe was calculated at a point just inside the penetration, in each of six degrees-of-freedom. These single-frequency piping loads were then combined into a single load at that point by absolute sum of the four largest components added to the SRSS of the balance. This was done for each degree of freedom. (The basis for this method of combining individual frequency components is discussed in Reference 14). The loads calculated in the pipe were then applied to the system as static loads; and pipe stress, penetration stress, and support loads were determined. A typical combined spectrum is illustrated in Figure 3-4.

TAP analysis for other loads noted above, was done by applying the appropriate load to the CG of the affected area and performing static analysis.

3.3.7 TAP Penetration Analysis

Analysis of torus penetrations included the following loads:

- Loads from piping response due to shell motion (Mark 1 loads).
- Loads due to submerged drag and/or pool impact, on internal sections of TAP, as applicable.
- Loads from weight, seismic and thermal conditions on the attached piping.
- Shell loads which exist due to the Mark 1 and other loads, independent of piping (from Reference 1).

The calculation of stress from the loads was done using a Bijlaard analysis (Reference 9) to account for local penetration stress due to piping loads. These were combined with free shell stresses in that area, intensified to account for the discontinuity. Free shell stress was taken from earlier containment analysis, as reported in Reference 1. Penetration stresses were calculated for each load in each degree of freedom. Stresses resulting from this analysis were combined to form the load cases defined in the PUAAG (Reference 9 and Table 1).

Stress in the piping within the limits of reinforcement was calculated by combining the stress in the pipe with the local shell stresses by absolute summation. This was also evaluated for each degree of freedom and each of the PUAAG load cases (Table 1).

3.3.8 Analysis Method for Piping Supports

Analysis was done for all piping supports for all TAP and branch systems. Calculations were made using both hand and computer analysis, depending on the complexity of the individual support. Evaluation of baseplates and anchor bolts was included, using the current procedures developed in response to NRC Bulletin 79-02 (Reference 3). The GTSTRUDL computer program was used in most cases where computer analysis of supports was done.

In cases where TAP supports were connected to the torus shell, local shell stresses were reevaluated to assure that shell allowables were not exceeded. This evaluation considered the free shell stress which was already calculated in the area of the support in Reference 1. These free shell stresses were intensified before being combined with the local stresses due to support loads.

3.3.9 Vacuum Breaker Analysis

The torus TAP systems include the atmospheric control lines which connect the main vent pipe to the the torus airspace, and which include the wetwell-to-drywell vacuum breakers. Analysis of these vacuum breakers was not a part of the Mark 1 Containment Program, but is reported in Reference 13. This reference concludes that the Vermont Yankee vacuum breakers will not cycle, due to Mark 1 dynamic loads. Based on this, no analysis of these valves was done.

3.3.10 Active Components

Active components on TAP systems include 11 pumps and 46 valves. Acceptability of these components was assured by limiting stresses at these locations, as described in the evaluation section. No analysis was necessary on these components.

3.4 Evaluation and Results (TAP)

3.4.1 General

Combinations of the previous analysis cases were done to allow evaluation of results in accordance with Table 5-5 of Reference 5. (Table 1 in this report.) This table lists a total of 27 load cases for both essential and non-essential piping systems. For purposes of this evaluation, all TAP systems are classified as essential.

The 27 load cases shown in Table 1 were reduced, by conservative bounding, to the cases listed below:

	Case No. (Table 1)	Major Load(s)	Allowable (Eq. 9)
1	3	SRV (C3.1) + SSE	1.2 S_h
2	16	Zero ΔP	2.4 S_h
3	21	DBA CO/CH + SSE	2.4 S_h
4	25	Pool Swell + SRV (A1.3)	2.4 S_h
5	15	Post Chug + SRV (A1.2)	2.4 S_h

In these cases, the seismic stresses were combined with the absolute sum of the Mark 1 dynamic loads by the the SRSS method, as applicable.

3.4.2 Piping Stress - Large Bore Systems

Stress in all large bore TAP systems was combined and evaluated in accordance with Section III of the ASME code for the five cases listed in Paragraph 3.4.1. These evaluations included the effects of local pipe stresses due to welded attachments at supports. Fatigue was considered as explained in Paragraph 3.4.6.

The large bore TAP systems are listed in Table 3-1 along with the maximum stress for the controlling load combination.

3.4.3 Pipe Stress - Small Bore TAP Systems

Evaluation of small bore TAP systems was the same as for large bore systems, except that the only Mark 1 dynamic load considered was DBA CO. This approach was based on experience gained in large bore analysis and is discussed further in Appendix 1.

Small bore systems are listed in Table 3-2.

3.4.4 Pumps and Valves

Evaluation of pumps and valves was done based on stresses in the adjacent piping. Pipe stresses meeting Level B criteria were considered adequate to assure proper operation of the pumps or valve. (Reference 5, Section 5.5).

Results of the pump and valve evaluation are listed in Table 3-3.

3.4.5 Piping Fatigue Evaluation

Consideration of the fatigue effects of cyclic loading is reported in Reference 10 for bounding Mark 1 plants. This reference defines bounding conditions and concludes that the stress levels and cycles involved in these systems will not produce a fatigue problem. The conclusions are applicable to the Vermont Yankee Plant. No further plant unique evaluation was done to address fatigue considerations for piping. Fatigue for the penetration is considered below.

3.4.6 Torus Shell Penetration Evaluation

Evaluation of torus penetration stresses considered loads from the external and internal piping, as well as the loads that exist in the shell, due to the same event(s). Shell stress away from penetrations is reported in Reference 1.

Stresses in the penetration area were evaluated in accordance with subsection NE of The ASME code, using the following paragraphs:

NE-3221.2	Local Membrane Stress Intensity
NE-3221.3	Primary General or Local Membrane plus Primary Bending Stress Intensity
NE-3221.4	Primary plus Secondary Stress Intensity
NE-3221.5	Analysis for Cyclic Operation
NE-3227.5	Nozzle Piping Transition

Fatigue evaluation of the penetration (paragraph NE-3221.5) showed that the maximum load could be cycled on each penetration for at least 10,000 cycles without exceeding code allowables. The major loads that form these load combinations are pool swell (1 cycle), DBA.CO (900 cycles), and SRV Case C3.3 (50 cycles). Other loads; normal SRV actuation, IBA CO, and chugging, can produce up to 10,000 cycles, but only at greatly reduced stress levels. Based on this, the 10,000 cycles at maximum stress represents a conservative level of evaluation and the TAP shell penetrations are considered acceptable for fatigue.

Controlling stresses in the TAP penetrations are listed in Table 3-5. Additional information of number of cycles for each condition can be found in Reference 10.

This same evaluation was applied to TAP supports connected to the torus shell, except that NE-3227.5 does not apply.

3.4.7 Piping Supports

All piping supports on the TAP systems were evaluated for the same load combinations as the piping (Table 1).

Evaluation was done in accordance with AISC, 1978 Edition and included the following criteria:

- Expansion type anchor bolts and baseplates were evaluated in accordance with Bulletin 79-02 criteria (Reference 3).
- No stresses in pipe supports were allowed to exceed yield, regardless of pipe stress allowables.

A listing of pipe supports and modifications is given in Table 3-4.

3.5 Summary of TAP Modifications

Modifications to torus attached piping systems consisted of support changes, as well as modifications to internal piping.

Modifications to internal piping included shortening some lines to reduce submergence and drag loads; rerouting one line and supporting it from the ring girder and resupporting one other. The following modifications were made; these are illustrated in Reference 1:

- Reroute RHR line and support from ring girder.
- Reinforce spray header supports on the ring girders.
- Shorten RCIC exhaust line.

Modifications to external piping consisted of support and support steel modifications as summarized in Table 3-4 of this report.

TABLE 3-1

VERMONT YANKEE

LARGE BORE TAP RESULTS

System Name	Penetration Number	Line Size & Schedule	Controlling Load Case	Maximum Stress	Allowable Stress	Max. Stress Location
CS-3	X-226B	12" Std.	DBA CO	21663	36000	16 x 12 Reducing Elbow
HPCI-8	X-225	16" Std.	Full "△P" Pool Swell	27973	36000	Elbow
HPCI-6	X-221	24" Sch. 30	Chug	32781	36000	SR Elbow
AC-1	X-218	8" Std.	Seismic (with SRV)	21190	27000	18 x 8 Tee
RHR-6	X-224A	24" Std.	DBA CO	35956	36000	SR Elbow
AC-2	X-205	20" Std.	Seismic (with SRV)	26218	27000	20 x 20 Tee
RCIC-1	X-227	6" Std.	Full "△P" Pool Swell	23633	36000	6 x 6 Tee
CS-2/RHR-7 (Model A)	X-210A/X-211A	4" Std.	Full "△P" Pool Swell	26459	36000	12 x 4 Tee
CS-6	X-210B/X-211B	10" Std.	Seismic (with SRV)	22962	27000	Two-Way Restraint
MISC. 4/4A RHR-5/5B (Model 3)	X-224B	20" Std.	Seismic (with SRV)	25947	27000	SR Elbow

TABLE 3-1 (CONTINUED)

VERMONT YANKEE

LARGE BORE TAP RESULTS

System Name	Penetration Number	Line Size & Schedule	Controlling Load Case	Maximum Stress	Allowable Stress	Max. Stress Location
CS-4	X-226A	12" Std.	Seismic (with SRV)	16901	27000	12 x 12 Tee
RCIC-5	X-212	8" Sch. 80	0 "△P" Pool Swell	29773	32880	LR Elbow Inside Torus
Vacuum Breaker	X-202A-F	18" Std.	Seismic (with SRV)	7447	18000	Elbow
Vacuum Breaker	X-202 H&K, G&J	18" Std.	DBA CO	27746	36000	Elbow

TABLE 3-2

VERMONT YANKEE

SMALL BORE TAP RESULTS

System Name	Penetration Number	Line Size & Schedule	Type of Analysis	Maximum Stress	Allowable Stress	Max. Stress Location
Radiation Monitor Return	X-216	Sch. 80	Computer	31,697	37,152	Valve
Oxygen Analyzer	X-220	1" Sch. 80	Computer	18,600	36,000	Valve
HPCI Turbine Cond. Drain	X-222	2" Sch. 80	Computer	28,755	36,000	Elbow Near Penet.
RCIC Turbine Cond. Drain	X-223	2" Sch. 80	Computer	24,623	36,000	1" Drain Line
	X-206A	1" Sch. 80	Hand	9,628	36,000	Penetration
	X-206B, C, D	1" Sch. 80	Hand	10,247	36,000	Penetration
	X-206E, F	1" Sch. 80	Hand	3,541 (CO < 10%)	36,000	Penetration
	X-209A,B,C,D X-215	1" Sch. 80 to ½"	Hand	15,313	36,000	Penetration
	X-214	4" Sch. 80	Hand	1,627 (CO < 10%)	36,000	Penetration
	X-217	2" Sch. 80	Hand	5,004	36,000	Penetration

TABLE 3-3

VERMONT YANKEE

PUMP AND VALVE EVALUATION

Component Designation	Component Type	TAP System	TAP Penetration	Pipe Stress at Component	Allowable Pipe Stress
P-46-1A	Pump	CS-3	X-226B	6257	18000
Booster Pump	Pump	HPCI-8	X-225	5613	18000
TU-1-1A	HPCI Turbine	HPCI-6	X-221	3624	18000
P-47-1A	Pump	RCIC-1	X-227	4524	18000
P-46-1B	Pump	CS-2/RHR-7	X-210A/X-211A	10308	18000
P46-1A	Pump	CS-6	X-210B/X-211B	7444	18000
P-10-1C	Pump	Misc. 4/4A, RHR-5/5B	X-224B	17517	18000
P-10-1A	Pump	"	X-224B	17501	18000
P-46-1B	Pump	CS-4	X-226A	9510	18000
P-10-1B	Pump	RHR-6	X-224A	15584	18000
P-10-1D	Pump	RHR-6	X-224A	13615	18000
MOV10-138	Mtr. Oper. Valve	RHR-6	X-224A	5263	18000
CS-26A	Mtr. Oper. Valve	CS-6	X-210B/X-211B	16425	18000
CS-7A	Mtr. Oper. Valve	CS-3	X-226B	8428	18000
CS-8A	Man. Oper. Valve	CS-3	X-226B	9812	18000

TABLE 3-3 (CONTINUED)

VERMONT YANKEE

PUMP AND VALVE EVALUATION

Component Designation	Component Type	TAP System	TAP Penetration	Pipe Stress at Component	Allowable Pipe Stress
HPCI-17	Mtr. Oper. Valve	HPCI-8	X-225	3941	18000
HPCI-57	Mtr. Oper. Valve	HPCI-8	X-225	6417	18000
HPCI-58	Mtr. Oper. Valve	HPCI-8	X-225	7286	18000
V23-32	Check Valve	HPCI-8	X-225	8685	18000
V23-61	Check Valve	HPCI-8	X-225	6666	18000
HPCI-12	Man. Oper. Valve	HPCI-6	X-221	10930	18000
HPCI-65	Check Valve	HPCI-6	X-221	6438	18000
V-SBGT-1A	Butterfly Valve	AC-1	X-218	1354	18000
V-SBGT-2A	Butterfly Valve	AC-1	X-218	1606	18000
V-SBGT-1B	Butterfly Valve	AC-1	X-218	1372	18000
V-SBGT-2B	Butterfly Valve	AC-1	X-218	1580	18000
V-SBGT-4A	Butterfly Valve	AC-1	X-218	1221	18000
V-SBGT-4B	Butterfly Valve	AC-1	X-218	1220	18000
MOV-SB-6	Butterfly Valve	AC-1	X-218	3712	18000
SB16-19-6A	Butterfly Valve	AC-1	X-218	4494	18000

TABLE 3-3 (CONTINUED)

VERMONT YANKEE

PUMP AND VALVE EVALUATION

Component Designation	Component Type	TAP System	TAP Penetration	Pipe Stress at Component	Allowable Pipe Stress
SB16-19-7A	Butterfly Valve	AC-1	X-218	7523	18000
SB16-19-6B	Butterfly Valve	AC-1	X-218	4183	18000
SB16-19-7B	Butterfly Valve	AC-1	X-218	5738	18000
SB16-19-10	Butterfly Valve	AC-2	X-205	4789	18000
SB16-19-11B	Butterfly Valve	AC-2	X-205	4889	18000
V16-19-12B	Check Valve	AC-2	X-205	1844	18000
V16-19-12A	Check Valve	AC-2	X-205	2021	18000
SB16-19-11A	Butterfly Valve	AC-2	X-205	6693	18000
RCIC-18	Mtr. Oper. Valve	RCIC-1	X-227	5089	18000
V13-19	Check Valve	RCIC-1	X-227	6741	18000
RCIC-39	Mtr. Oper. Valve	RCIC-1	X-227	9925	18000
RCIC-40	Check Valve	RCIC-1	X-227	6349	18000
RCIC-41	Mtr. Oper. Valve	RCIC-1	X-227	5355	18000
V14-10A	Check Valve	CS-6	X-210B/X-211B	8112	18000

TABLE 3-3 (CONTINUED)

VERMONT YANKEE

PUMP AND VALVE EVALUATION

Component Designation	Component Type	TAP System	TAP Penetration	Pipe Stress at Component	Allowable Pipe Stress
RHR-V-15C	Mtr. Oper. Valve	Misc. 4, 4A RHR-5, 5B	X-224B	6724	18000
V10-15A	Mtr. Oper. Valve	"	X-224B	7116	18000
V10-13C	Mtr. Oper. Valve	"	X-224B	16271	18000
V10-13A	Mtr. Oper. Valve	"	X-224B	5367	18000
CS-7B	Mtr. Oper. Valve	CS-4	X-226A	7492	18000
CS-8B	Man. Oper. Valve	CS-4	X-226A	4575	18000
RCIC-28	Man. Oper. Valve	RCIC-5	X-212	2100	18000
V13-50	Check Valve	RCIC-5	X-212	14050	18000
RCIC-9	Mtr. Oper. Valve	RCIC-5	X-212	16705	18000
RCIC-37	Man. Oper. Valve	RCIC-5	X-212	5830	18000
N/A	Check Valve	AC	X-202F	5318	18000
N/A	Check Valve	AC	X-202H	13672	18000
N/A	Check Valve	AC	X-202K	17156	18000

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1001, Sh. 1	ACSP-HD228	E-W Lateral	Yes
	ACSP-HD22A (2030)	Spring Can	Yes
	ACSP-H22	Axial	Yes
	ACSP-H23	N-S Lateral	Yes
	ACSP-HD25B	Gravity Hanger	Removed
	ACSP-HD25A	Gravity Hanger	Note 1
	ACSP-H204	E-W Lateral/ Gravity Hanger	Gravity Hanger Removed
	ACSP-HD26A (2031)	Spring Can	Yes
	ACSP-HD26B (1464)	Gravity Hanger	Note 1
	ACSP-H26	N-S/E-W Lateral	Yes
	ACSP-H27	N-S/E-W Lateral Rigid Vertical	Yes
	ACSP-H27B	N-S/E-W Lateral	Yes
	ACSP-H27A	Gravity Hanger	Removed
	ASCP-HD31B	Gravity Hanger	Removed
	ACSP-H31	N-S Lateral/ Rigid Vertical	Removed
	ACSP-HD31A	Gravity Hanger	Removed
	ACSP-H34	E-W Lateral	No
	ACSP-HD34 (1465)	Gravity Hanger	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1001, Sh. 1	ACSP-H199	Anchor	Yes
	ACSP-H110 (1446)	Gravity Hanger	Note 1
PI-1001, Sh. 2	ACSP-HD205C (1447)	Gravity Hanger	Note 1
	ACSP-HD205B	Gravity Hanger	No
	ACSP-HD205A	Rigid Vertical	No
	ACSP-H205	Axial	No
	ACSP-H119	Rigid Vertical	No
	ACSP-HD-202B (1449)	Gravity Hanger	Note 1
	ACSP-HD202A (1448)	Gravity Hanger	Note 1
	ACSP-H202	E-W Lateral	No
	ACSP-HD203F (2033)	Gravity Hanger	Yes
	ACSP-H203	E-W Lateral/Axial	No
	ACSP-HD203E (1450)	Gravity Hanger	Note 1
	ACSP-HD203D (1453)	Gravity Hanger	Note 1
	ACSP-HD203B	Gravity Hanger	No
	ACSP-HD203C (1452)	Gravity Hanger	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1001, Sh. 2	ACSP-HD203A (1451)	Gravity Hanger	Note 1
	ACSP-HD30A (2035)	Spring Can	Yes
PI-1002, Sh. 1	ACSP-HD30B (2036)	Spring Can	Yes
	ACSP-H30 (1102)	N-W/E-W Lateral/ Rigid Vertical	Yes
	ACSP-HD30C (2037)	Spring Can	Yes
	ACSP-H32 (1125)	Anchor	Yes
	ACSP-HD32A (1454)	Gravity Hanger	Note 1
	ACSP-H32A	E-W Lateral/ Rigid Vertical	New Design
	ACSP-HD32B (2038)	Spring Can	Yes
	ACSP-H29	Gravity Hanger	Note 1
	ACSP-HD32C (2039)	Spring Can	Yes
	ACSP-H28	Gravity Hanger	Note 1
	ACSP-HD213 (1455)	Gravity Hanger	Note 1
	ACSP-HD214 (1456)	Gravity Hanger	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1002, Sh. 1	ACSP-HD215 (1457)	Gravity Hanger	Note 1
	ACSP-HD216	N-S/E-W Lateral	No
	ACSP-HD221 (2040)	Spring Can	Yes
	ACSP-HD220 (2041)	Gravity Hanger	Yes
PI-1004, Sh. 2	ACSP-HD217 (1103)	N-S Lateral/ Rigid Vertical	Yes
	RSW-H98 (1459)	Gravity Hanger	Note 1
	ACSP-HD218 (1458)	Gravity Hanger	Note 1
	ACSP-HD227	N-S Lateral	New Design
	RSW-HD224 (1460)	Gravity Hanger	Note 1
	ACSP-H219 (2042)	Spring Can	Yes
	ACSP-HD225	N-S Lateral/ Rigid Vertical	New Design
	ACSP-HD226	Anchor	New Design
PI-1010, Sh. 1	CS-HD42	Gravity Hanger	Note 1
	CS-H42	E-W Lateral	Yes
	CS-H43	Gravity Hanger	Note 1
	CS-H84	E-W Lateral	Yes

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1010, Sh. 1	CS-HD84	Spring Can	Removed
	CS-H45	N-S/E-W Lateral	Yes
	CS-HD46	N-S/E-W Lateral	Yes
	CS-H46	N-W/E-W Lateral	No
	CS-HD55B	N-S Lateral/ Rigid Vertical	Yes
	CS-H55	N-S Lateral/Axial	Yes
	CS-HD55A	Gravity Hanger	Removed
	CS-HD85D	Rigid Vertical	No
	CS-HD85C	N-S Lateral/Axial	Yes
	CS-HD85B	Spring Can	Removed
	CS-H56	N-S Lateral	No
	CS-H85	E-W Snubber	Removed
	CS-HD85A	Gravity Hanger	Removed
PI-1010, Sh. 2	CS-HD86B	Spring Can	Removed
	CS-HD86A	Spring Can	Note 1
	CS-HD86C (2097)	Spring Can	Changed to spring/ vertical snubber
	CS-H86A	Lateral Snubber	Changed to rigid lateral
	CS-H86B	Axial Snubber	Changed to rigid axial
	RHR-HD134 (1033)	Spring/Vertical Snubber	New Design

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1010, Sh. 2	RHR-H134	Lateral	Removed
	RHR-HD134A	Spring Can	Removed
PI-1010, Sh. 3	RHR-HD101	N-S/E-W Lateral	Removed
	RHR-H101 (1107)	E-W Lateral/Axial	Yes
	CS-HD87D	Spring Can	Removed
	CS-HD87C	Spring Can	Removed
	RHR-H98	N-W/E-W Lateral	Changed to 5-way restraint
	CS-HD87A	N-S/E-W Lateral	No
	CS-H87	Lateral	No
PI-1133, Sh. 1	RHR-HD241	Anchor	No
	RHR-H103 (1111)	Gravity Hanger	Note 1
	RHR-HD16G (1113)	E-W Lateral	New Design
	RHR-HD16F	Spring Can	Removed
	RHR-HD16D	Gravity Hanger	Removed
	RHR-HD16H (1114)	E-W Lateral	New Design
	RHR-HD16E	Gravity Hanger	Removed
	RHR-H16	Anchor	Yes
	RHR-HD16C (1112)	Gravity Hanger	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1133, Sh. 1	RHR-HD16B	Spring Can	Removed
	RHR-HD16J (1115)	Lateral	New Design
	RHR-HD16A	Gravity Hanger	Removed
PI-1133, Sh. 2	RHR-H186 (1110)	N-S Lateral	Yes
	RHR-HD186A (1119)	Rigid Vertical	New Design
	RHR-HD188D	Spring Can	Removed
	RHR-HD186	Spring Can	Removed
	RHR-H154	Anchor	Removed
	RHR-HD154	Gravity	Removed
	RHR-HD129E (1120)	E-W Lateral	New Design
	RHR-HD129A	Gravity Hanger	Removed
	RHR-H129B	Spring Can	Removed
	RHR-H129 (1108)	N-S Lateral	Yes
	RHR-HD129C (1118)	Gravity Hanger	Yes
	RHR-HD129D	Gravity Hanger	Removed
	RHR-HD188A (1116)	Gravity Hanger	Yes
	RHR-HD188B	Gravity Hanger	Removed
	RHR-H188 (1109)	Lateral Snubber	Changed to 2-way rigid lateral

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1133, Sh. 2	RHR-HD188C (1117)	Spring Can	Note 1
PI-1011, Sh. 1	CS-HD57C (2043)	Spring Can	Yes
	CS-H57	N-S Lateral	Yes
	CS-HD57A	Gravity Hanger	Note 1
	CS-HD57B	Gravity Hanger	Note 1
	CS-HD57D	N-S Lateral	New Design
	CS-HD88A (2044)	Spring Can	Yes
	CS-H88	Lateral	No
	CS-HD88B (1466)	Gravity Hanger	Note 1
	CS-HD88C (2045)	Spring Can	Yes
	CS-HD88D (1461)	Gravity Hanger	Note 1
	CST-H15	Anchor	Yes
PI-1012, Sh. 1	CS-HD60C	Spring Can	No
	CS-H60	N-S Lateral	Changed to vertical/lateral
	CS-HD60B (2050)	Spring Can	Note 1
	CS-HD60A	Gravity Hanger	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1012, Sh. 1	CS-HD60A	Gravity Hanger	Note 1
	CS-HD58E	Spring Can	No
	CS-HD58F	E-W Lateral	New Design
	CS-H59	Anchor	No
	CS-HD58A	Gravity Hanger	No
	CS-H58	Lateral	No
	CS-HD58B	Spring Can	No
	CS-HD58C (2049)	Spring Can	Yes
	CS-HD58D (1462)	Gravity Hanger	Note 1
PI-1013, Sh. 1	CS-H47 (1463)	Gravity Hanger	Note 1
	CS-H48	Gravity Hanger	No
	CS-H49 (1101)	E-W Lateral	Yes
	CS-HD52B (2053)	Spring Can	Yes
	CS-HD52A (2054)	Spring Can	Yes
	CS-H52	N-S/E-W Lateral Rigid Vertical	Yes
	CS-H89	Lateral	Yes
	CS-HD89 (2055)	Spring Can	Yes

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1013, Sh. 1	CS-HD89 (2055)	Spring Can	Yes
	CS-H54	N-W/E-W Lateral	Yes
	CS-HD90C	N-S Snubber	New Design
	CS-HD90B	Gravity Hanger	Note 1
	CS-HD90	N-S Lateral	Changed to N-S lateral/axial
	CS-HD90A (1467)	Gravity Hanger	Note 1
	CS-HD61C	Gravity Hanger	No
	CS-H61	N-S Lateral/Axial	Yes
	CS-HD61B (2056)	Spring Can	Yes
	CS-HD61A	Gravity Hanger	No
PI-1013, Sh. 2	CS-HD54G	Gravity Hanger	Note 1
	CS-HD54A (2096)	Spring Can	Changed to spring/ lateral snubber
	CS-HD54B (2060)	Spring Can	Yes
	CS-HD54H	Axial Snubber	New Design
	CS-HD54C	Gravity Hanger	Note 1
	CS-HD54F (2059)	Spring Can	Yes
	CS-HD54D (2058)	Spring Can	Yes

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1013, Sh. 2	CS-HD54E	Gravity Hanger	Note 1
	RHR-H83	Anchor	Yes
PI-1064, Sh. 1	HPCI-HD103 (2061)	Spring Can	Yes
	HPCI-H108	E-W Lateral	Yes
	HPCI-HD108B (2062)	Spring Can	Yes
	HPCI-HD39 (2063)	Spring Can	Yes
	HPCI-H39	N-S Lateral	Yes
	HPCI-H107	Gravity Hanger	Note 1
	HPCI-HD107A (2064)	Spring Can	Yes
	HPCI-HD109A	Spring Can	No
	HPCI-H109	Lateral	Yes
	HPCI-HD109B	Gravity Hanger	Note 1
	HPCI-HD109C	Gravity Hanger	Note 1
	HPCI-H44	N-S/E-W Lateral	Yes
	HPCI-HD107B	Spring Can	No
	HPCI-HD107C (2067)	Spring Can	Yes
PI-1066, Sh. 1	HPCI-HD84 (2068)	Spring Can	Yes

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1066, Sh. 1	HPCI-H84	Rigid Vertical	Yes
	HPCI-H85	E-W Lateral	Yes
	HPCI-H85A (2069)	Spring Can	Yes
	HPCI-HD85	Spring Can	Removed
	HPCI-H110	N-S Lateral	Yes
	HPCI-HD110	Spring Can	No
	HPCI-HD111A (2072)	Spring Can	Yes
	HPCI-HD111B (2073)	Spring Can	Yes
	HPCI-H111	E-W Lateral	No
	HPCI-HD113	Gravity Hanger	Note 1
	HPCI-H113	Anchor	Yes
PI-1100, Sh. 1	RCIC-H84A,B,C	Anchor	Yes
	RCIC-H65	Rigid Vertical/ Lateral	Yes
	RCIC-HD64C	Spring Can	No
	RCIC-HD64B	Spring Can	No
	RCIC-HD64A (2075)	Spring Can	Yes
	RCIC-H64	Lateral	Yes
	RCIC-HD63A	Anchor	Yes

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1100, Sh. 1	RCIC-H63	Lateral	Yes
	RCIC-HD63B	Spring Can	No
	RCIC-HD63C	Lateral	Yes
	RCIC-H62	Gravity Hanger	Note 1
PI-1104, Sh. 1	RCIC-HD32	Gravity Hanger	Note 1
	RCIC-H32	N-S/E-W Lateral/ Rigid Vertical	Changed to rigid vertical
	RCIC-H86	Lateral	Changed to 2-way lateral
	RCIC-HD87 (2078)	Spring Can	Yes
	RCIC-H87	Lateral	Yes
PI-1104, Sh. 2	RCIC-H79	2-Way Lateral	No
	RCIC-H88	2-Way Lateral	No
	RCIC-HD88 (2079)	Spring Can	Yes
PI-1131, Sh. 1	RHR-H128 (1079)	N-S/E-W Lateral	Changed to anchor
	RHR-HD128	Gravity Hanger	Removed
	RHR-H181	E-W Lateral	Yes
	RHR-HD181 (1084)	Gravity Hanger	Note 1
	RHR-H22	Anchor	Yes

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1131, Sh. 1	RHR-H182	N-S Lateral/ Gravity Hanger	No
	RHR-HD240	Anchor	No
PI-1131, Sh 2	RHR-HD184	Gravity Hanger	Removed
	RHR-HD184A	Lateral	New Design
	RHR-HD184B	E-W Lateral N-S Snubber	New Design
	RHR-H184	Spring Can	Note 1
	RHR-H183	Lateral Snubber	Yes
	RHR-H183C	Spring Can	Removed
	RHR-HD183B (2084)	Gravity Hanger	Changed to spring
	RHR-HD183A	Gravity Hanger	Removed
	RHR-H185	Lateral Snubber	No
	RHR-HD185A	Gravity Hanger	Removed
	RHR-HD185B	Gravity Hanger	Removed
	RHR-H185C	Gravity Hanger	Removed
	RHR-HD185E	Gravity Hanger	Removed
	RHR-HD185F	Lateral	New Design
	RHR-HD-185D (2080)	Gravity Hanger	Changed to spring
PI-1140, Sh. 1	RHR-HD1	N-S/E-W Lateral	No
	RHR-HD2 (1091)	Gravity Hanger	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1140, Sh. 1	RHR-HD18R (1099)	N-S Lateral	New Design
	RHR-HD3	Gravity Hanger	Removed
	RHR-HD4 (1092)	Gravity Hanger	Yes
	RHR-HD18P (1098)	E-W Lateral	New Design
	RHR-HD5	Gravity Hanger	Removed
	RHR-HD6 (1090)	Gravity Hanger	Yes
	RHR-HD7	Gravity Hanger	Removed
	RHR-HD8 (1180)	N-S/E-W Lateral	Changed to anchor
	RHR-HD8A	Gravity Hanger	Removed
	RHR-HD8B (1089)	Gravity Hanger	Note 1
	RHR-HD18G	Gravity Hanger	Removed
	RHR-HD18N (1097)	E-W Lateral	New Design
	RHR-HD18F	Gravity Hanger	No
	RHR-HD18E (1078)	Gravity Hanger	Added E-W lateral support
	RHR-HD18D	Gravity Hanger	Removed
	RHR-HD18C (1087)	Gravity Hanger	Yes
	RHR-HD18M (1096)	E-W Lateral	New Design

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1140, Sh. 1	RHR-HD18L (1095)	Axial	New Design
	RHR-HD18B	Gravity Hanger	Removed
	RHR-HD18A (2090)	Gravity Hanger	Yes
	RHR-HD18	N-S/E-W Lateral	No
	RHR-HD18K (1094)	N-S Lateral	New Design
	RHR-HD18H	Gravity Hanger	Removed
	RHR-HD18J (1093)	E-W Lateral	New Design
	CUN-HD50 (1085)	Gravity Hanger	Yes
PI-1080, Sh. 1	CUN-H49 (1077)	N-S/E-W Lateral	Yes
PI-1081, Sh. 1	CUN-HD49A (1075)	Anchor	Yes
	CUN-HD49N (1470)	Vertical Strut	New Design
	CUN-HD49B	Gravity Hanger	Removed
	CUN-HD49C	Gravity Hanger	Removed
	CUN-HD49E (1082)	Gravity Hanger	Note 1
	CUN-HD-49F	Gravity Hanger	Removed
	CUN-HD49G	Gravity Hanger	Removed

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
PI-1081, Sh. 1	CUN-HD49M (1083)	Axial	New Design
	CUN-HD49H (1081)	Gravity Hanger	Changed to N-S lateral
	CUN-HD49K	Gravity Hanger	Removed
	CUN-HD49L	Gravity Hanger	Removed
PI-1132, Sh. 1	RHR-H127	N-S/E-W Lateral	Yes
	RHR-HD127A (1468)	Gravity Hanger	Note 1
	RHR-HD127B	Gravity Hanger	Removed
	RHR-HD127M	N-S Snubber	New Design
	RHR-HD127C	Gravity Hanger	Yes
	RHR-HD127D	Gravity Hanger	Note 1
	RHR-HD127E (2082)	Spring Can	Yes
	RHR-HD127F	Gravity Hanger	Note 1
	RHR-HD127G	Gravity Hanger	Note 1
	RHR-HD127H (1469)	Gravity Hanger	Note 1
	RHR-HD127I	Spring Can	No
	RHR-HD127L	Lateral Snubber	New Design
	RHR-HD127J	Gravity Hanger	Note 1
PI-1132, Sh. 2	RHR-HD127K (1407)	Gravity Hanger	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-4

VERMONT YANKEE

TAP PIPE SUPPORTS

Dwg. No.	Support I.D.	Support Type	Modified
2" RCIC-13	RCIC-HD-200 (A-8540)	Gravity	Note 1
	RCIC-HD-201 (A-8539)	Vertical/Lateral	Yes
2" HPCI-16	HCIC-HD-200 (A-8538)	Gravity	Note 1

Note 1: Single-acting hanger changed to double-acting vertical support.

TABLE 3-5

TAP PENETRATION STRESS RESULTS - VERMONT YANKEE

Penetration Number	Primary Stress: Calculated Max. Stress	Primary Stress: Allowable	Secondary Stress: Calculated Max. Stress	Secondary Stress: Allowable
X-202F	12273	19300	65524	69,900 (3.0 S_{mi})
X-203F	17110	19300	44042	
X-202H&K	12461	19300	47097	
X-203H&K	12226	19300	35918	
X-205	14030	19300	68087	
X-210A	28651	28900	59449	
X-210B	17554	19300	37040	
X-211A	14108	15100	33775	
X-211B	14108	15100	33775	
X-212	10751	15100	56136	
X-218	12350	19300	52491	
X-221	27385	28900	66549	
X-224A	14172	19300	64689	
X-224B	25058	28900	60722	
X-225	23974	28900	67591	
X-226A	13861	19300	51342	
X-226B	14135	19300	65385	
X-227	14009	15100	47971	

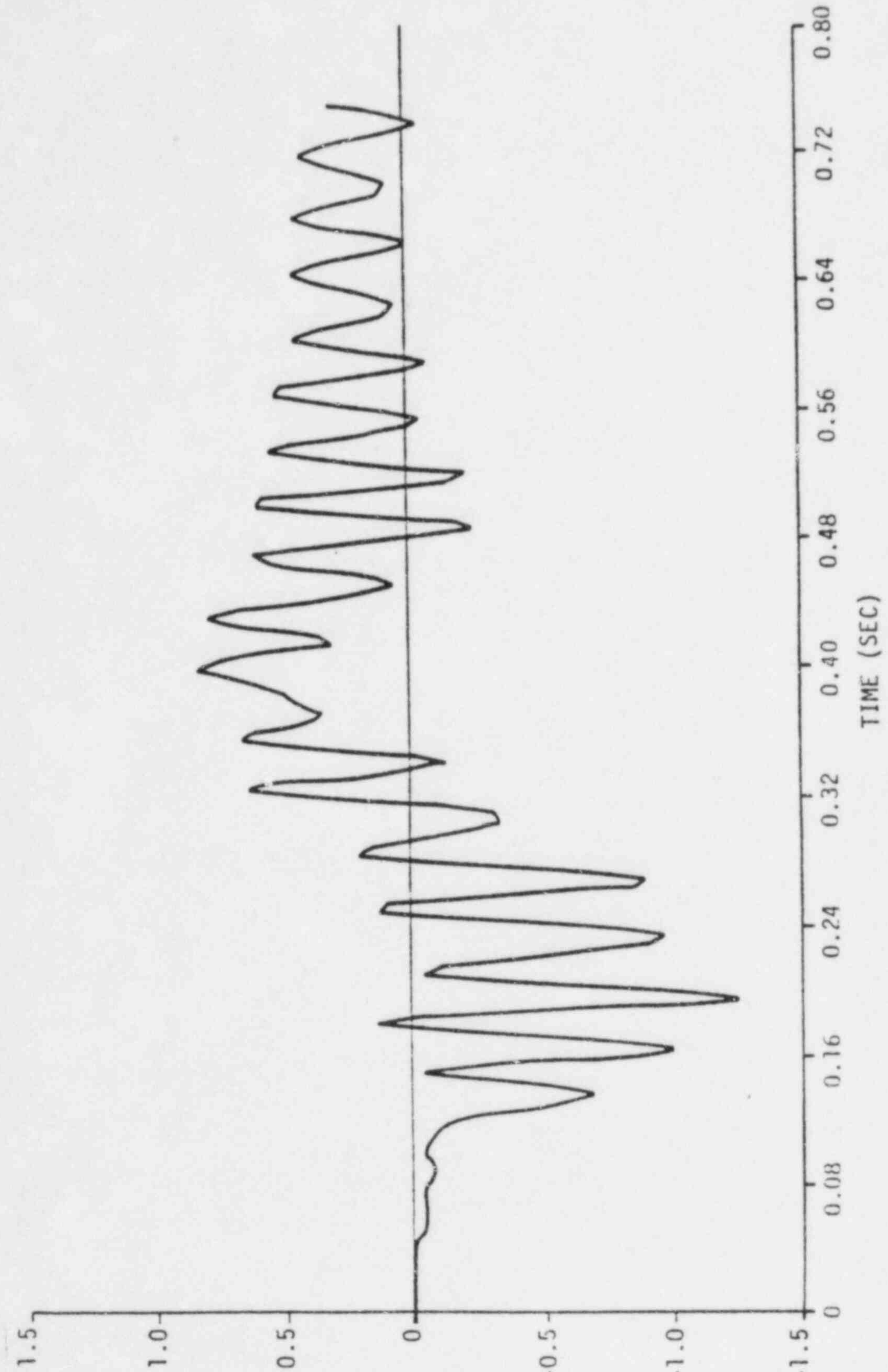


FIGURE 3-1 SHELL RESPONSE FROM POOL SWELL, TYPICAL

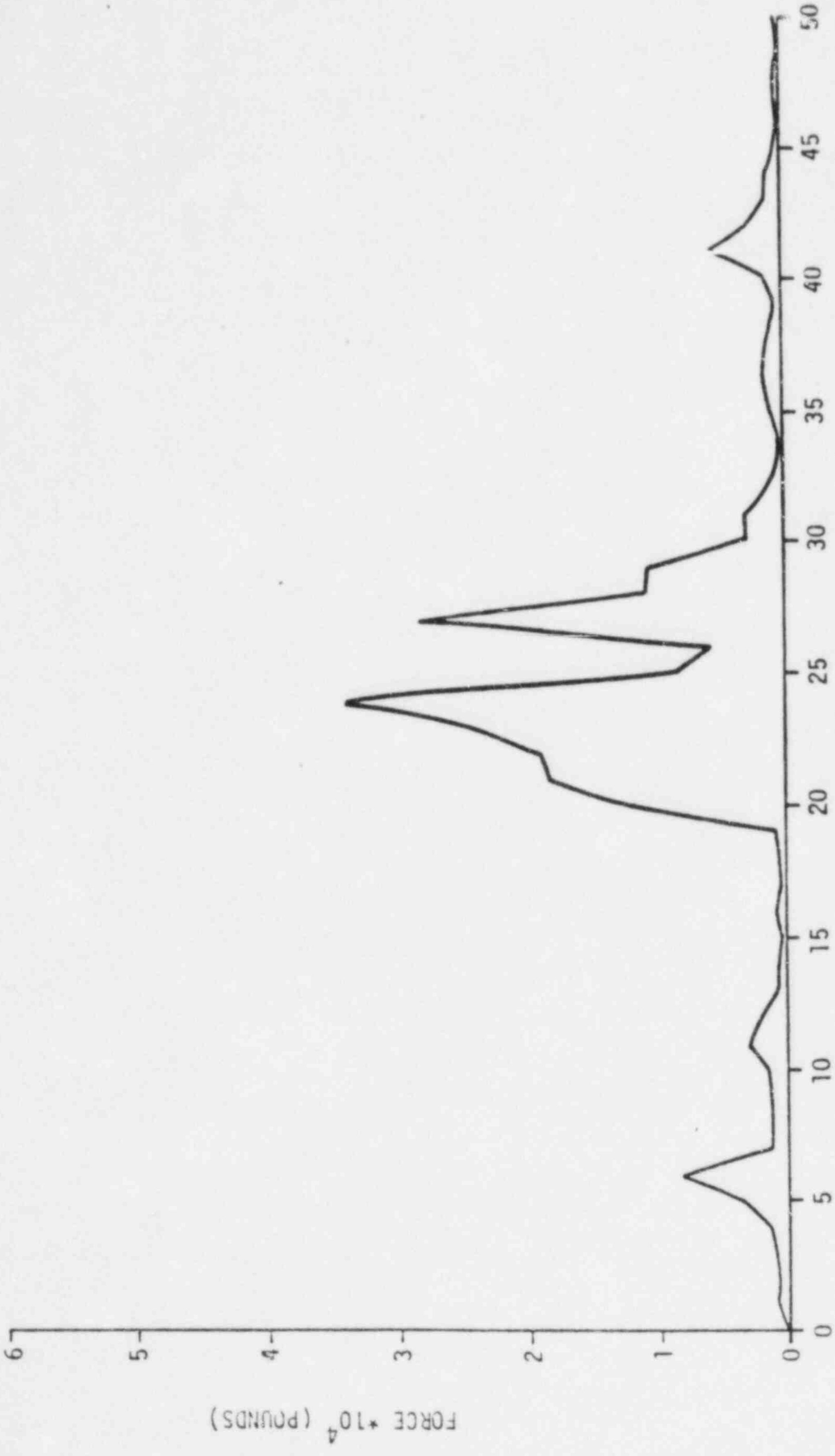


FIGURE 3-2 SHELL RESPONSE FROM CONDENSATION OSCILLATION-TYPICAL

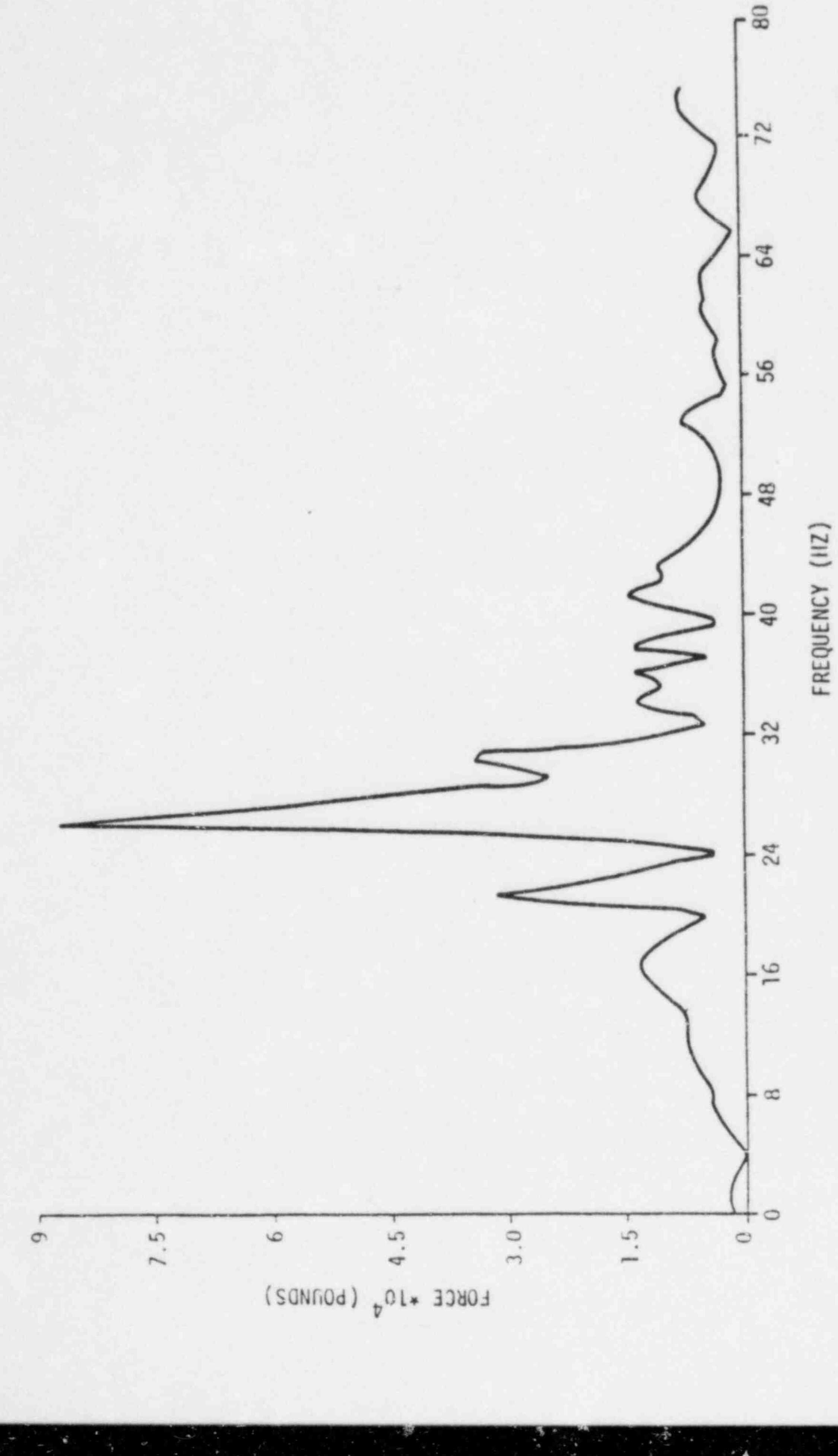


FIGURE 3-3 SHELL RESPONSE FROM SRV-TYPICAL

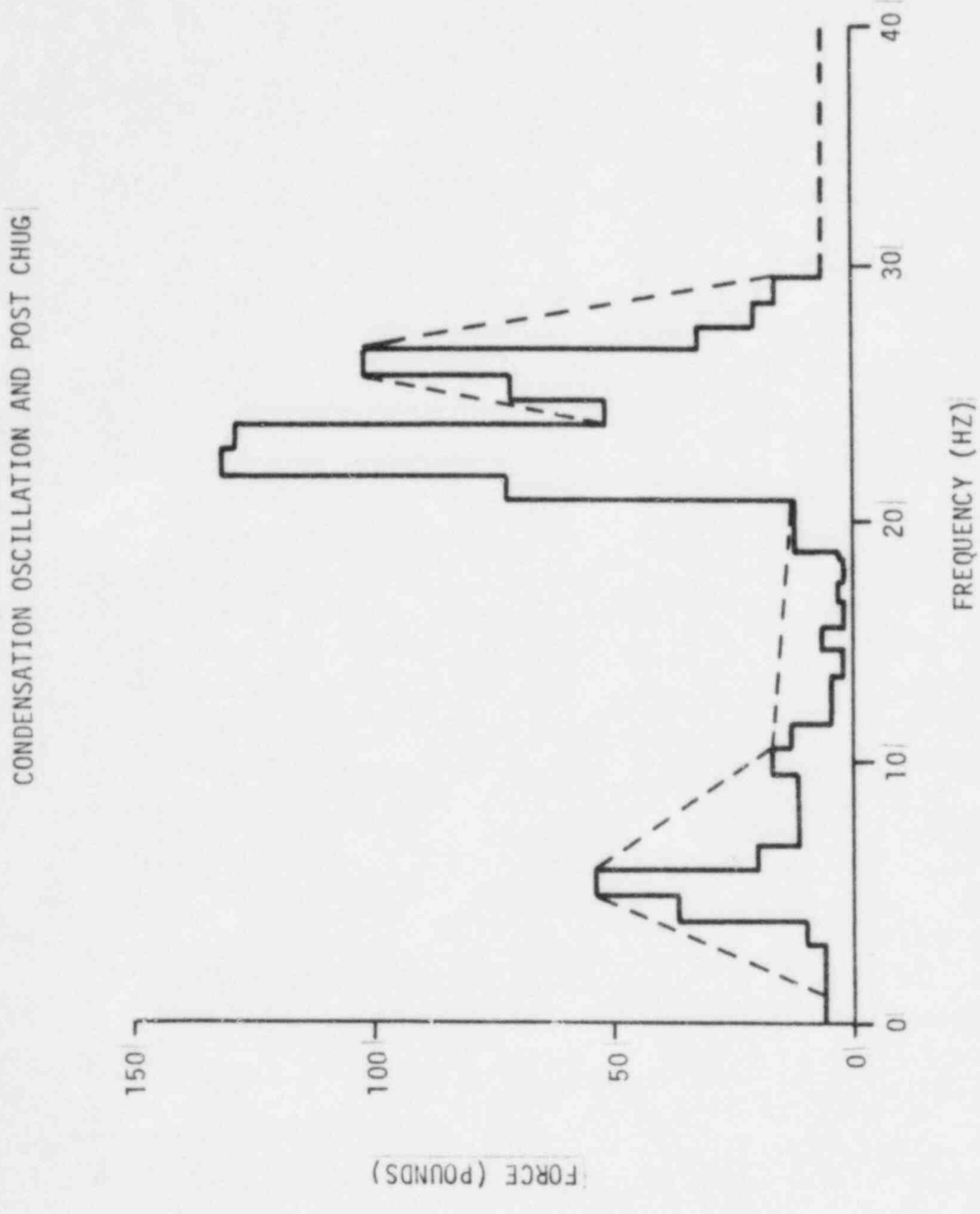


FIGURE 3-4 LOAD ON INTERNAL PIPING

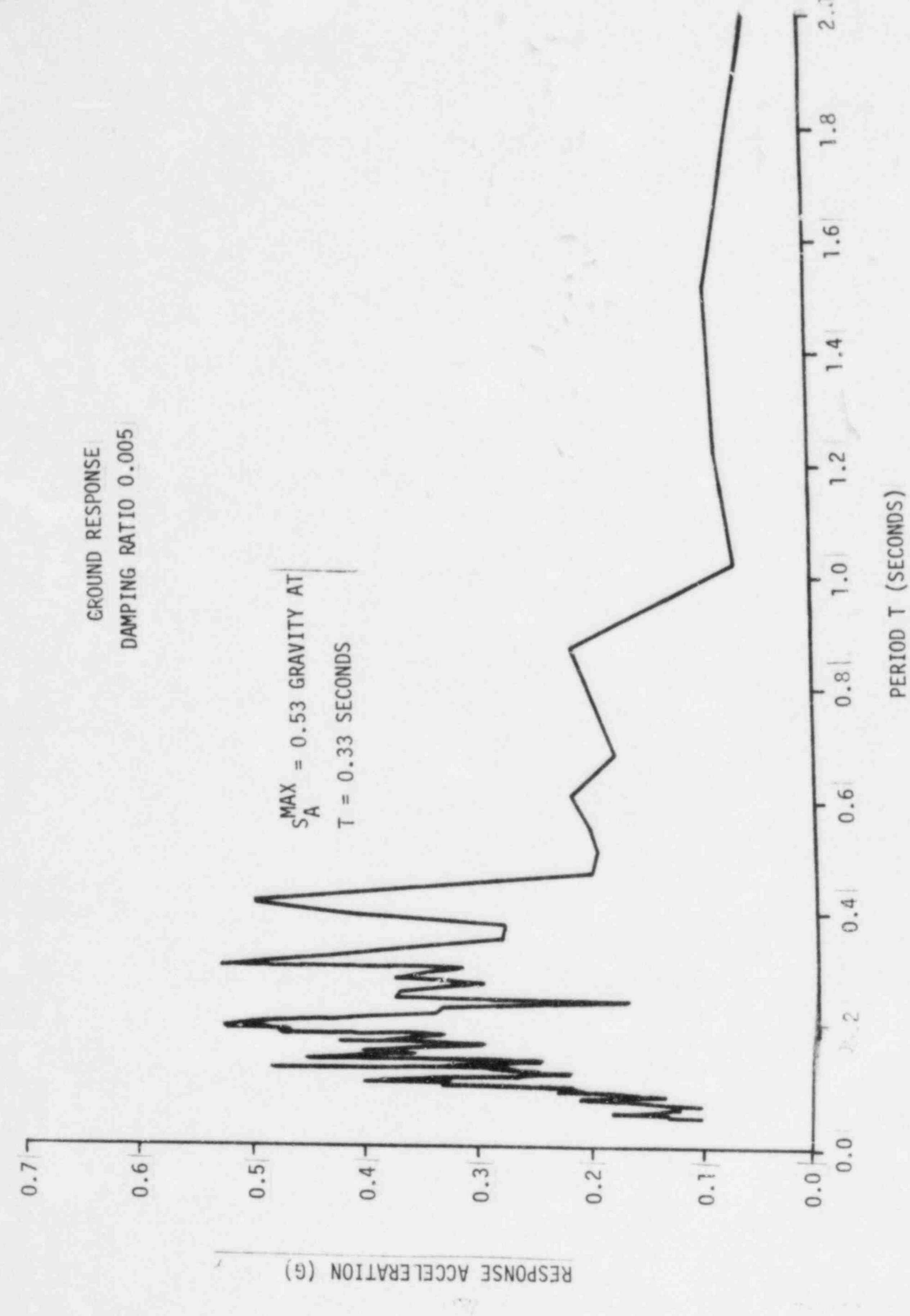


FIGURE 3-5 TAP SEISMIC HORTIZONTAL SPECTRA,TYPICAL

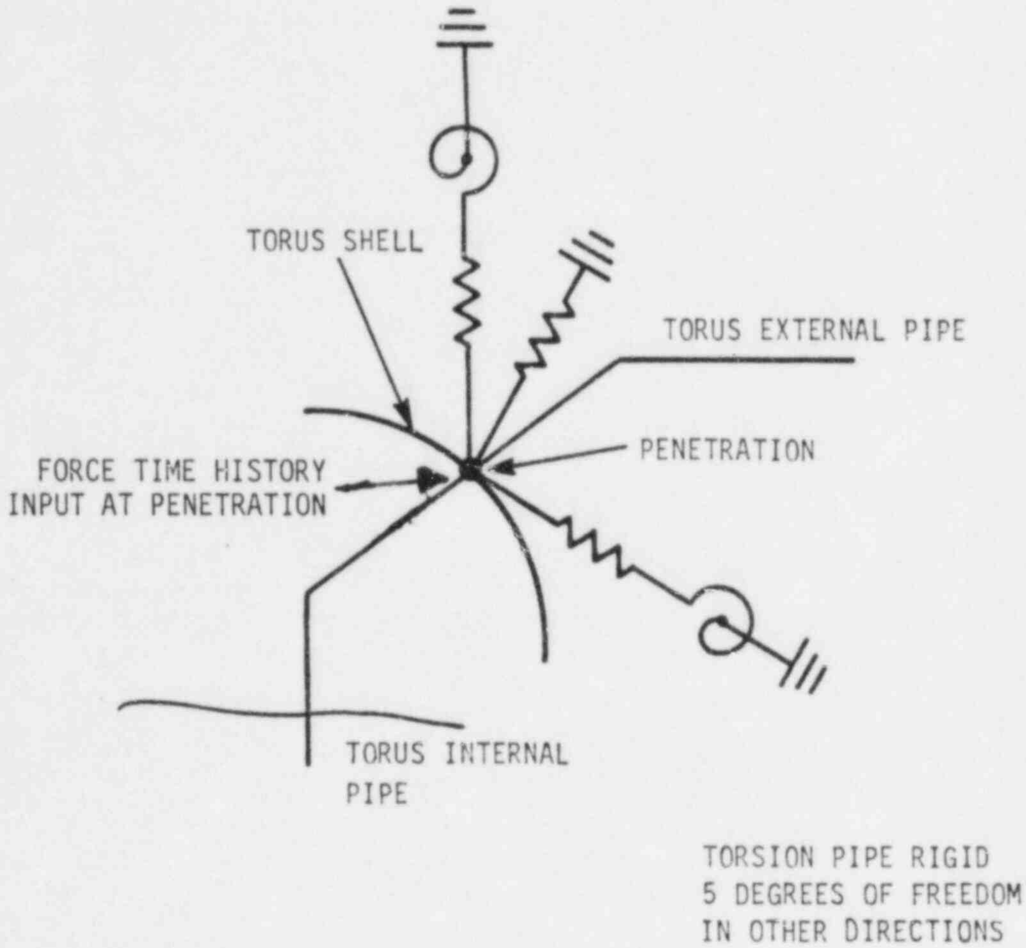
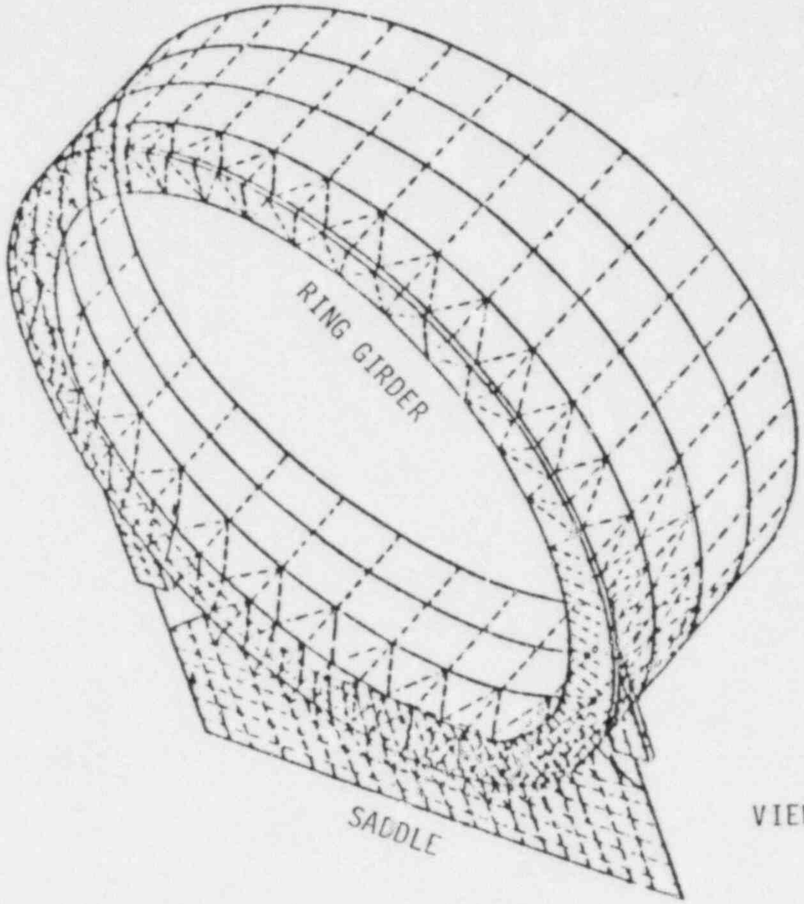


FIGURE 3-6 TAP PENETRATION REPRESENTATION (TYPICAL)



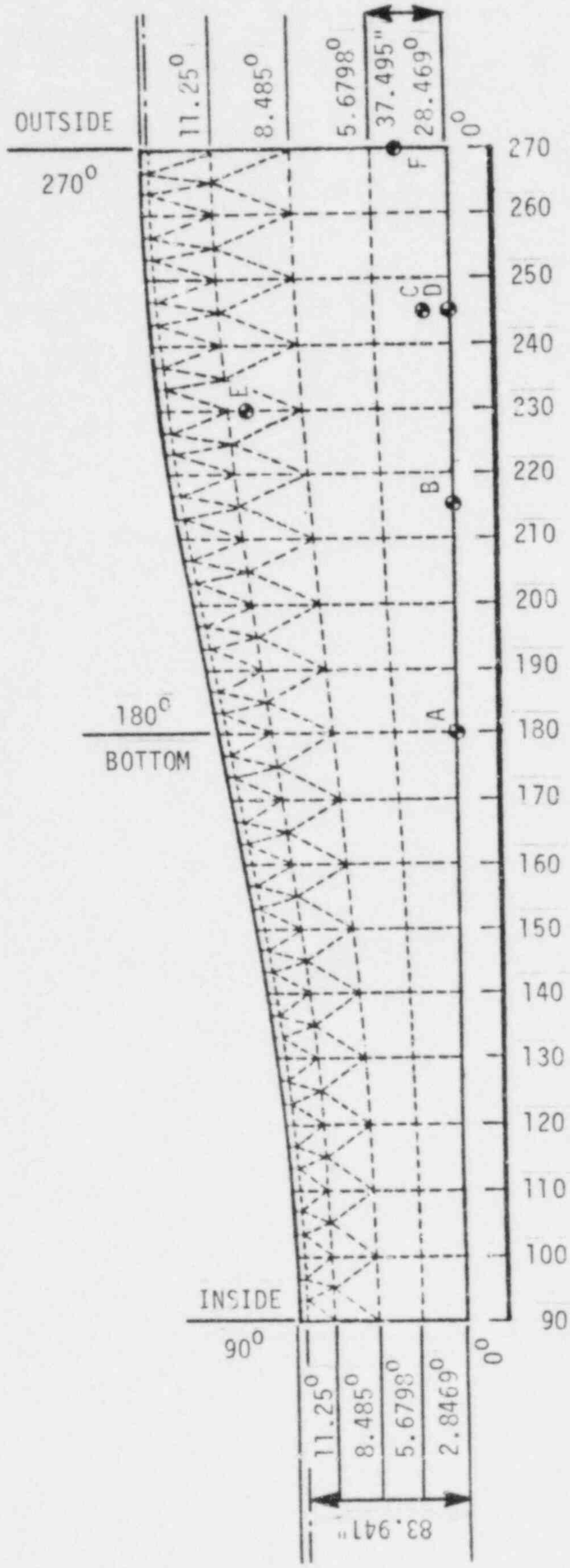
VIEW ROTATED AXIS

VERMONT YANKEE NUCLEAR PLANT

FIGURE 3-7 DETAILED SHELL MODEL

TORUS PENETRATIONS

NODE NO.	LOCATION	PENETRATION NO.	ANGLE
19	A	x213a-b	180°
23	B	x224a-b	217.50°
25	C	x209b-c	245.00°
26	D	x206b-c	245.00°
146	E	x225,226a-b x227	230.00°
--	F	x222,223	269.00°

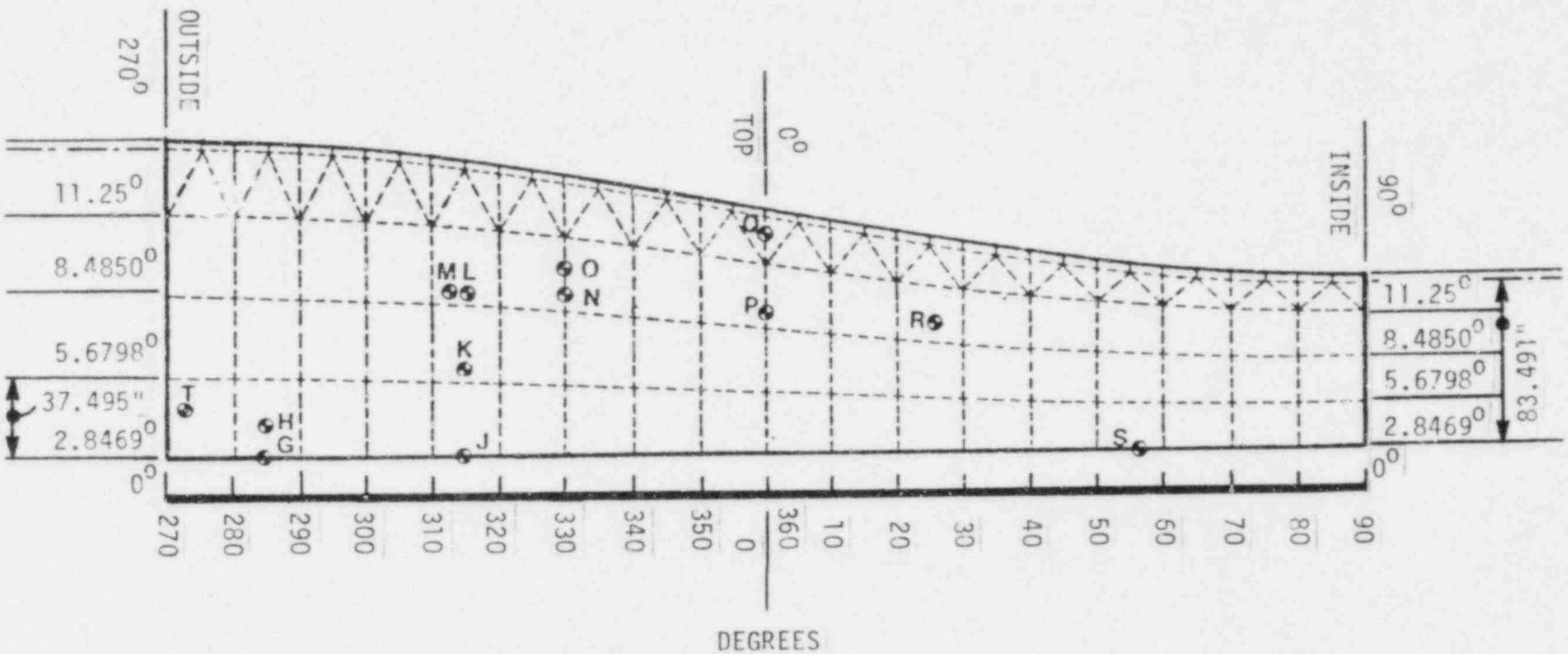


VERMONT YANKEE NUCLEAR PLANT

FIGURE 3-8a PENETRATION LOCATIONS

TORUS PENETRATIONS

NODE NO.	LOCATION	PENETRATION NO.	ANGLE
29	G	x206a,d	285.00^{0}
30	H	x209a,d	285.00^{0}
33	J	x202a-h	319.40^{0}
69	K	x202j-k	319.40^{0}
--	L	x200a-b	319.40^{0}
104	M	x205	316.60^{0}
106	N	x215-x219	330.00^{0}
--	O	x214spare	330.00^{0}
73	P	x211a-b	000.00^{0}
109	Q	x220	0.00^{0}
111	R	x210a-b	25.700^{0}
--	S	x201a-h	57.60^{0}
64	T	x212,x221	272.40^{0}



VERMONT YANKEE NUCLEAR PLANT

FIGURE 3-8b PENETRATION LOCATIONS

REFERENCES

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2. ASME B&PV Code, Section III, Division 1, through Summer 1977.

3. USNRC IE Bulletin 79-02, dated November 8, 1979, (Revision 2), Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts.

4. ASME B&PV Code, Section XI, 1977 Edition, with 1978 Addenda.

5. G.E. Report NEDO-24583-1, "Mark 1 Containment Program Structural Acceptance Criteria Plant Unique Analysis Application Guide", dated October, 1979.

6. Structural Mechanics Report SMA-12101.05-R001, "Design Approach for FSTF Data for Combining Harmonic Amplitudes for Mark 1 Post-Chug Response Calculations", dated May, 1982.

7. General Electric Computer Program RVFOR-04, A Program to Compute SRV Line Clearing Forces, General Electric Company, San Jose, Calif.

8. Intentionally Omitted.

9. Welding Research Council Bulletin No. 107, "Local Stresses in Spherical and Cylindrical Shells due to External Loadings", dated March, 1979.

10. General Electric Report No. MPR-751 "Mark 1 Containment Program, Augmented Class 2/3 Fatigue Evaluation Method and Results for Typical Torus Attached and SRV Piping Analysis", dated November, 1982.

11. G.E. Report NEDO-21888, Rev. 2, "Mark 1 Containment Program Load Definition Report", dated November, 1981.

REFERENCES (CONTINUED)

12. NRC "Safety Evaluation Report, Mark 1 Containment Long-Term Program", NUREG-0661, dated July, 1980.

13. Vermont Yankee letter No. 2.C.2.1-FVY83-36, J. Sinclair (YAEC) to D. Vassallo (NRC) "Modification of Vacuum Breakers for mark 1 Containments" dated May 11, 1983.

14. Structural Mechanics Assoc. Report SMA-12101.04-R002D "Response Factors Appropriate for use with CO Harmonic Response Combination Design Rules", dated March, 1982.

Table 1

CLASS 2 AND 3 PIPING SYSTEMS

EVENT COMBINATIONS		SRV	SRV + EQ		SBA IBA		SBA + EQ IBA + EQ				SBA + SRV IBA + SRV		SBA + SRV + EQ IBA + SRV + EQ				DBA		DBA + EQ				DBA + SRV		DBA + EQ + SRV			
						CO, CH			CO,CH			CO, CH			CO,CH		PS (1)	CO, CH	PS		CO,CH		PS	CO, CH	PS		CO,CH	
TYPE OF EARTHQUAKE			O	S			O	S	O	S			O	S	O	S			O	S	O	S			O	S	O	S
COMBINATION NUMBER		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
LOADS																												
Normal (2)	N	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Earthquake	EQ		X	X			X	X	X	X			X	X	X	X			X	X	X	X			X	X	X	X
SRV Discharge	SRV	X	X	X							X	X	X	X	X	X							X	X	X	X	X	X
Thermal	T_A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Pipe Pressure	P_A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
LOCA Pool Swell	P_{PS}																X		X	X			X		X	X		
LOCA Condensation Oscillation	P_{CO}					X			X	X		X			X	X		X			X			X			X	
LOCA Chugging	P_{CH}					X			X	X		X			X	X		X			X	X		X			X	X
STRUCTURAL ELEMENT	ROW																											
Essential Piping Systems																												
With IBA/DBA	10	B	B (3)	B (3)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)	B (4)
With SBA	11				B (3)	B (3)	B (4)	B (4)	B (4)	B (4)	B (3)	B (3)	B (4)	B (4)	B (4)	B (4)	-	-	-	-	-	-	-	-	-	-	-	-
Nonessential Piping Systems																												
With IBA/DBA	12	B	C (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)
With SBA	13				C (5)	C (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	D (5)	-	-	-	-	-	-	-	-	-	-	-	-

NOTES TO TABLE 1

1. Where drywell-to-wetwell pressure differential is normally utilized as a load mitigator, an additional evaluation shall be performed without SRV loadings, but assuming the loss of the pressure differential. Service Level D Limits shall apply for all structural elements of the piping system for this evaluation. The analysis need only be accomplished to the extent that integrity up to and including the first pressure boundary isolation valve is demonstrated, including operability of that valve. If the normal plant operating condition does not employ a drywell-to-wetwell pressure differential, the listed Service Level assignments shall be applicable.

2. Normal loads (N) consist of dead loads (D).

3. As an alternative, the 1.25 S_h limit in Equation 9 of NC-3652.2 may be replaced by Level C (1.85 S_h) provided that all other limits are satisfied. Fatigue requirements are applicable to all columns with the exception of 16, 18, 19, 22, 24 and 25.

4. Footnote 3 applies, except that instead of using Level C (1.8 S_h) in Equation 9 of NC-3652.2, Level D (2.4 S_h) may be used.

5. Equation 10 of NC or ND-3650 shall be satisfied, except that fatigue requirements are not applicable to columns 16, 18, 19, 22, 24 and 25, since pool swell loadings occur only once. In addition, if operability of an active component is required to ensure containment integrity, operability of that component must be demonstrated.

APPENDIX 1

USE OF CO LOAD FOR SMALL BORE PIPING

Experience with large bore piping analysis showed that DBA condensation oscillation was usually the most severe Mark 1 load for torus attached piping. This is consistent with the continuous nature of the CO load (as opposed to the transient nature of some other Mark 1 loads) and the frequency content of CO, which is in a range of typically high piping response.

Experience on large bore piping for the first three plants completed by TES follows:

	No. of Large Bore Systems Available for Evaluation	No. Controlled by CO or Seismic*
Pilgrim	14	11
Millstone	11	9
Vermont Yankee	13	11
	38	31

Of the seven cases not controlled by CO, CO loads were very close to the maximum, as follows:

Ratio of CO Case to Controlling Stress Case

Pilgrim - .999, .953, .958

Millstone - .89, .65(1)

Vermont Yankee - .960, .53(2)

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*Evaluation did not include drag loags on internal piping - small bore systems do not have internal piping.

In five of these seven cases, CO stresses are practically equal to the controlling cases. The other two cases, indicated by (1) and (2) appear to be special cases that do not apply to small bore piping.

Case (1) is an atmospheric control (vacuum breaker) line that connects at three points at the top of the torus. The multiple connections and the penetration location make this line particularly susceptible to pool swell impact on the upper shell. There is no comparable small bore system.

Case (2) is an RCIC return line which has a long internal section which is responding at a high level to shell motion. The maximum stress in this line is inside the torus. There is no comparable small bore system.

The decision to limit analysis of small bore piping to DBA CO as the only Mark 1 load was based on the foregoing. Seismic, thermal and weight were also considered, in addition to DBA CO.

APPENDIX 2

32 Hz Cutoff for Condensation Oscillation Analysis

All condensation oscillation response of TAP systems due to torus shell motion used an input frequency cutoff of 32 Hz.

This practice began early in the TAP analysis work and was the result of a decision to cut off shell response frequencies at 32 Hz during the containment analysis. The 32 Hz cutoff for containment analysis is discussed in Appendix 2 of Reference 1, and was based on the fact that both high input energy and high modal responses occurred below that frequency. Use of the 32 Hz cutoff was shown to produce only a small error that was considered negligible. On this same basis, the 32 Hz cutoff was applied to CO analysis for TAP.

Later in the TAP analysis work, it became evident that the 32 Hz cutoff would not be realistic for post chug; input frequencies to 50 Hz were used for post chug. At this time, the decision to cut off CO frequencies at 32 Hz was reviewed. Spectra were generated for several penetrations showing the CO shell motion up to 50 Hz. Figures A4-1, A4-2, A4-3 and A4-4 illustrate typical spectra for rotation and displacement at TAP penetration points for a similar torus, analyzed by TES. These show clearly that shell response above 32 Hz is negligible for CO, and support the initial position.

FIGURE A4-1
DBA CO SHELL RESPONSE-RADIAL
(UNLOADED SHELL-NODE 37)

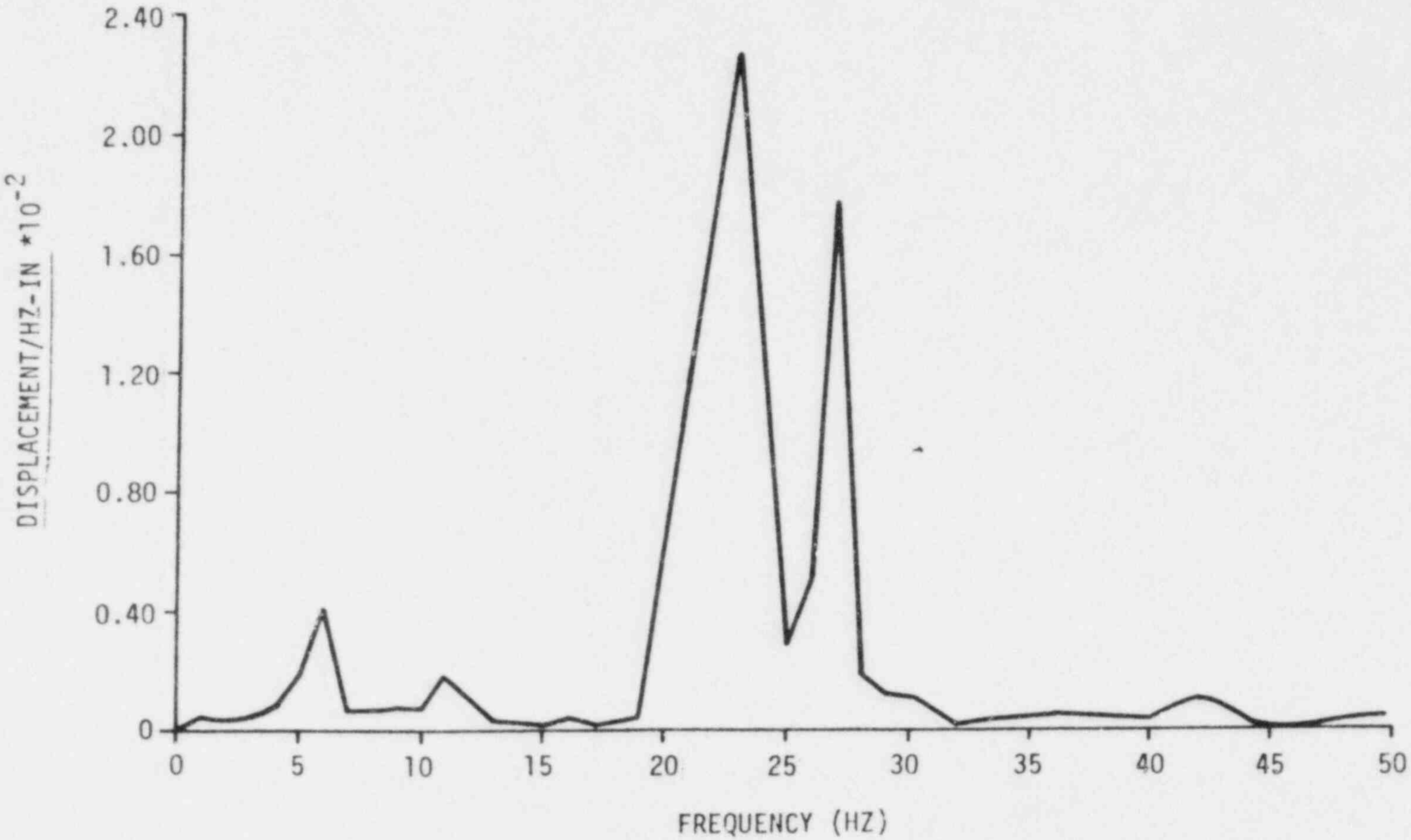

FIGURE A4-2

DBA CO SHELL RESPONSE-ROTATION

(UNLOADED SHELL-NODE 37)

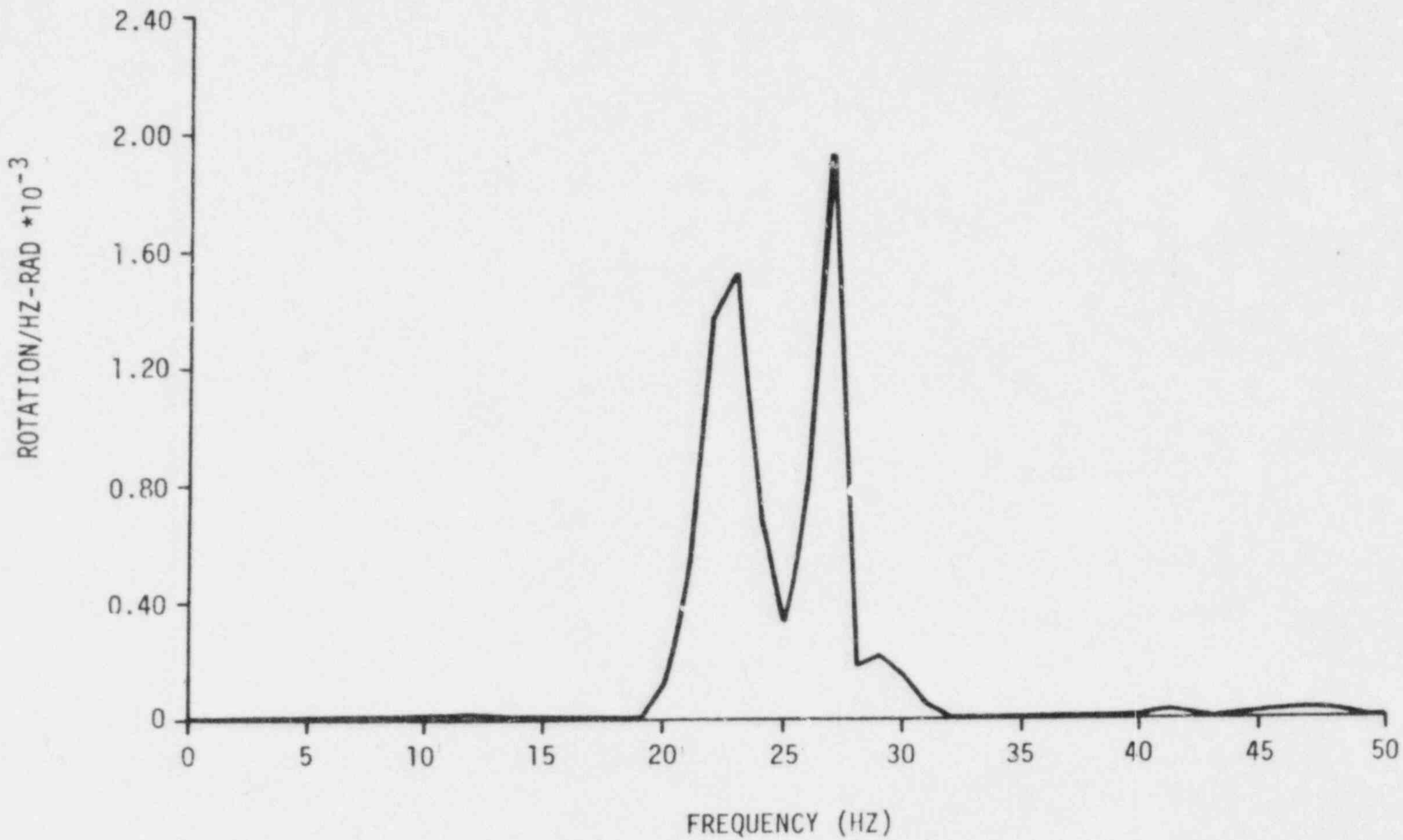

FIGURE A4-3

DBA CO SHELL RESPONSE-RADIAL

(UNLOADED SHELL-NODE 23)

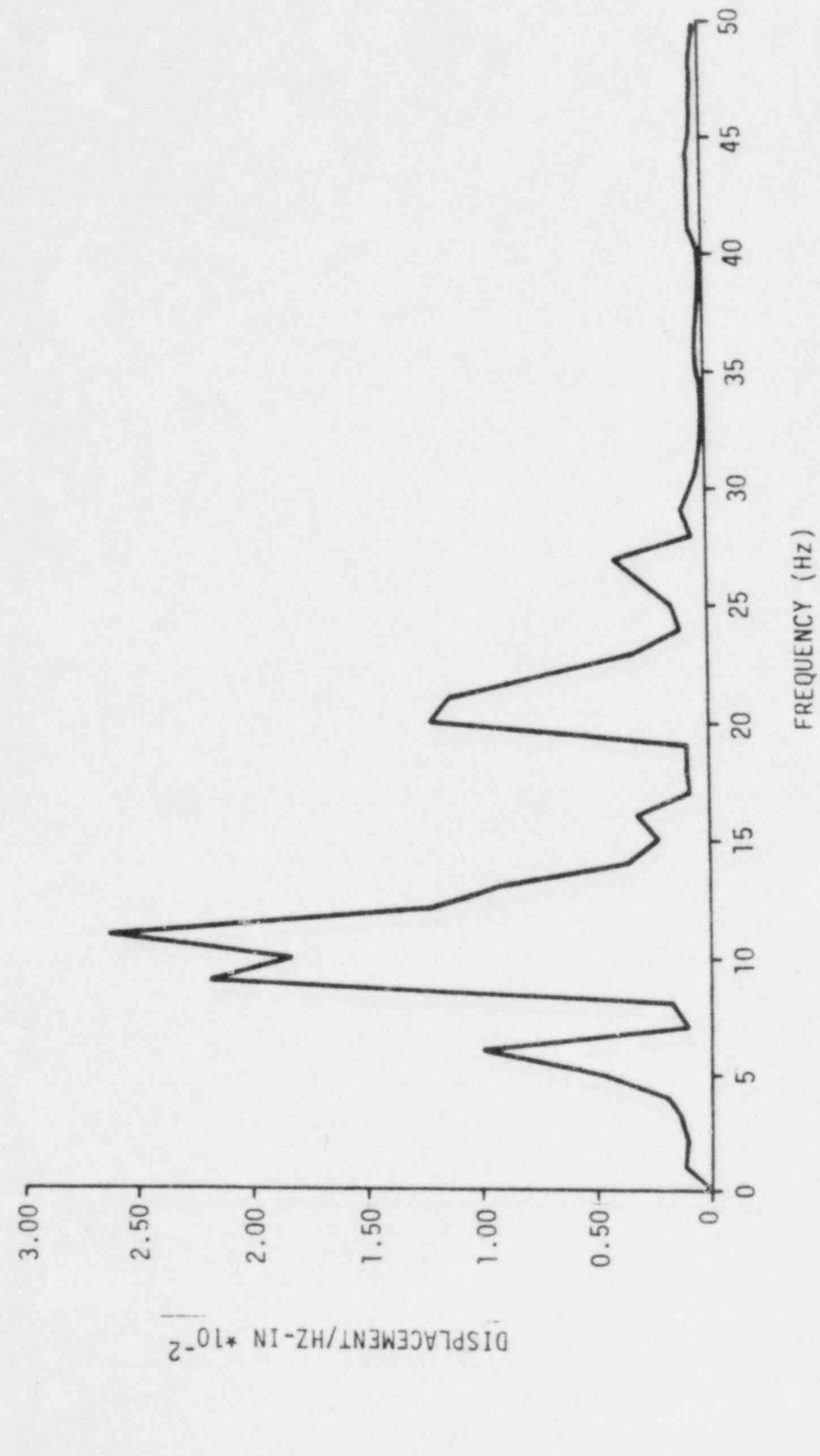

FIGURE A4-4

DBA CO SHELL RESPONSE-ROTATION

(UNLOADED SHELL-NODE 23)