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May 27, 1977

Regulatory Docket File

United States Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Office of Nuclear Reactor Regulation
Mr. Albert Schwencer, Chief

Reference: (1) License No. DPR-3 (Docket No. 50-29)
(2) USNRC letter to YAEC, dated 2/16/77
(3) YAEC letter to USNRC, dated 12/1/76
(4) YAEC letter to USNRC, dated 2/4/77
(5) YAEC letter to USNRC, dated 3/31/77

Subject: Reactor Vessel Overpressurization

Dear Sir:

Your letter, Reference (2), requested additional information after a preliminary review of our submittal, Reference (3). Our letters, References (4) and (5) stated, respectively, that Yankee Rowe has never experienced an overpressurization transient; and that an additional eight weeks would be required to provide further information.

Enclosed herewith is the information requested in Reference (2). We trust you will find this satisfactory; however, should you require additional detail, please contact Mr. R. P. Shone at (617) 366-9011, Extension 2830.

Very truly yours,

YANKEE ATOMIC ELECTRIC COMPANY

D.E. Vandenburgh

D. E. Vandenburgh
Senior Vice President

RHG/kg

RESPONSE TO NRC QUESTIONS REGARDING
THE YANKEE ROWE SUBMITTAL ON REACTOR VESSEL OVERPRESSURIZATION

The following questions pertain to formal discussions with all operators and Instrumentation and Control Technicians.

I.1.a. QUESTION: If you have not already completed the required formal discussion, when will you do so?

ANSWER: The formal discussion will be completed by June 4, 1977.

I.1.b. QUESTION: How will the discussions be held?

ANSWER: Formal discussions will be held at scheduled training meetings. The training session will be repeated until all Operating and Instrumentation and Control personnel have received the required training.

I.1.c. QUESTION: Identify which of the past Appendix G violations that have occurred at PWR facilities and which are described in Licensee Event Reports, are not credible in your plant due to equipment differences. Provide a description of the distinctions.

ANSWER: From the information available in the Licensee Event Report Summaries only a general response can be provided. The overpressurization incidents can be attributed to 4 or 5 general classifications. These incidents are:

1. Inadvertent ECCS operation.

2. Charging without bleed flow.

3. Loss of shutdown cooling heat removal capacity.

4. Main coolant flow initiation transients.

5. Direct operator error or improper procedural controls.

It is not possible to determine which events that have occurred at other PWR facilities are not credible at Yankee Rowe without more specific information about each of these other facilities. The information required would be system prints, instrumentation and control prints, any interlocks or permissive circuits available and operating procedure controls.

I.1.d. QUESTION: Describe, in detail, how you are reducing the likelihood of the other remaining credible events. Furnish schematics, diagrams or procedural summaries necessary to support the effectiveness and reliability of these measures.

ANSWER: Summaries of postulated events, design features and procedural controls which minimize the possibility of overpressurization events were provided as Appendices, A, B and C to Yankee Rowe's December 1, 1976 submittal to the Commission.

The effectiveness and reliability of these design features and administrative controls is documented by the fact that Yankee-Rowe, in its sixteen years of operation, has never experienced a reactor vessel overpressurization incident.

The following questions pertain to operations which are performed in the water-solid condition.

I.2.a. QUESTION: Discuss the necessity for establishing a water-solid system during each of these procedures. Also provide your justification for not using a nitrogen, air or steam bubble.

ANSWER: As described in detail in Appendix A to our original submittal, an air bubble is present in the pressurizer during the main coolant loop venting process. The water-solid condition is established only briefly during plant heatup in preparation for steam bubble formation and during plant cooldown for cooldown of the pressurizer. The water-solid condition is currently established only during heating or cooling of the pressurizer. This long-standing practice is based upon the assumption that the pressurizer should not be heated or cooled without being full of water in order to minimize thermal stress concentrations. Further evaluation of this assumption would be required if elimination of water-solid operation were contemplated.

Due to administrative controls, the inadvertent initiation of either main coolant flow or ECCS flow from a complete ECCS train is not a credible event while in the water solid condition. Moreover, the time spent in the water solid condition is small in comparison to the total time spent heating up or cooling down. Therefore, the additional protection afforded against reactor vessel overpressurization by eliminating this small duration of water-solid operation seems negligible.

I.2.b. QUESTION: Include any supplementary information such as system diagrams and descriptions of equipment operation to justify your need for operating the plant water-solid.

ANSWER: As stated in the response to Question No. I.2.a., it is currently assumed that the pressurizer should be full whenever it is being heated or cooled. This assumption is based upon information contained in the pressurizer technical manual which considers thermal stresses and stress concentration restrictions. An evaluation of the necessity of this long-standing operating practice would be performed before the current, minimal amount of water-solid operation could be eliminated.

The following questions pertain to inadvertent operation of SIS components.

I.3.a. QUESTION: Furnish a schematic diagram of the SIS showing the components and the flow paths into the RCS. Also, provide the head flow characteristics of each of the SIS pumps.

ANSWER: Attachment A is a schematic diagram of the SIS. Attachment B and C are pump characteristic curves for the low pressure and high pressure pumps respectively.

I.3.b. QUESTION: Pages A-1 and 2 of your submittal indicate that two of the three ECCS trains are taken out of service at 1000 psig and the third at 200°F, 300 psig. Describe how this is done, (e.g., switches or breakers repositioned). Indicate these trains on the requested schematic diagram.

ANSWER: A safety injection pump is removed from service by racking out, locking and tagging its ACB. A train consists of one high pressure and one low pressure pump. As indicated on Attachment A a train would be HPSI-1 and LPSI-1.

I.3.c. QUESTION: You discuss the closing of selected SI header isolation valves at 1000 and 300 psig. Is the power from these valves also removed? Indicate how and from where the valves are controlled. Identify them on the requested schematic diagram.

ANSWER: Below 1000 psig the following valves are closed but electrically operable: SI-MOV-22, SI-MOV-23, SI-MOV-24 and SI-MOV-25. At less than 300 psig the following valves are closed but electrically operable: SI-MOV-46, CS-MOV-533, CS-MOV-534, CS-MOV-535, CS-MOV-536, CS-MOV-537, CS-MOV-538 and CS-MOV-539. These valves are identified by their respective numbers on Attachment A, and are controlled remotely from the control room safety injection panel.

I.3.d. QUESTION: Indicate on the schematic diagram any other pumps that are disabled and valves which are in an off-normal position during a cold, and shutdown condition.

ANSWER: At less than 1000 psig the safety injection accumulator is removed from service by locking closed, tagging and making electrically inoperable, SI-MOV-1. In addition nitrogen regulator isolation valves SI-V-52A and SI-V-53A are tagged and locked closed and NS-V-19 is opened to vent the accumulator.

I.3.e. QUESTION: During cooldown or shutdown conditions other than fill and vent operation, for each SIS breaker opened (or "racked-out"), describe the following:

1. The SI component.

2. The breaker location.

3. The place from which the breaker's position can be controlled.

4. The places from which the breaker's position can be determined.

5. The position indication and status signals which will be lost as a result of opening or removing (rack-out) the breaker.

ANSWER: Each safety injection train is powered by its respective 480 volt emergency bus located in the safety injection building (i.e., HPSI-1 and LPSI-1 ACB's are located in No. 1 480 volt emergency bus.) Breaker position for the pumps can be determined both locally at the emergency bus and remotely from the control room. The pump ACB's are controlled only from the control room. By racking out these ACB's the position indication in the control room will be lost. SI-MOV-1 ACB is located in Emergency MCC No. 2 in the safety injection building. The breaker position can be determined locally. By opening the ACB an indirect indication of breaker position is given in the control room because valve position indication is lost. Once the ACB is closed the motor contactor for the valve can be controlled only remotely from the control room. In other words the valve cannot be operated from the motor contactor locally.

I.3.f. QUESTION: Describe the administrative controls that ensure the proper equipment alignment shown on the diagram. What supervisory personnel are responsible for maintaining control?

ANSWER: All equipment previously mentioned is initially positioned by plant operating procedures. All equipment which was locked and tagged in position is under continuous administrative control of the plant tagging procedures. Responsibility for maintaining the latter rests with the duty Shift Supervisor.

I.3.g. QUESTION: Below 1800 psig, automatic safety injection is blocked. Describe any "unblock" or "block-bypass" features you have, and how this factors into your pressure protection procedures.

ANSWER: At 1800 psig both of the safety injection actuation channel switches are positioned to "Cutout" which blocks any automatic initiation signal. There is no unblock or block bypass feature associated with the system. In addition, the six safety injection pump control switches are positioned at the remote panel to "Trip Pull Out". This means that the pumps would not start even if they did receive an "Auto Start" signal. In order for a pump to operate, two operating errors have to be made; the "Auto Start" signal must be reintroduced, and the pump control switch must be placed in an operable position.

I.3.h. QUESTION: The third ECCS train is not tagged out of service until the RCS has been cooled to around 200°F. What is the justification for not tagging out this ECCS train along with the others at 1000 psig, 360°F?

ANSWER: Technical Specification 3.5.3.a. requires that at least one safety injection train be operable in the manual mode above 200°F and between 300 and 1000 psig. This Technical Specification is an NRC requirement whose basis is not completely apparent.

I.3.i. QUESTION: During system fill and vent, you state on page A-3 that all ECCS pumps are tagged inoperable. Does this include the removal of power from all high pressure SIS pumps and motor operated header isolation valves? Show the equipment status on a SIS schematic. Describe the location of the breakers that will be opened, and the places from which they can be controlled. Describe the position indication and status signals which will be lost as a result of de-energizing these components.

ANSWER: At the time of main coolant system fill and venting, system temperature is less than ?00°F. Therefore, all safety injection pumps are tagged inoperable as stated in Answer #I.3.c., SI-MOV-1 is closed and locked as stated in ANswer #I.3.d., and all other SI system motor operated valves are positioned as stated in Answer #I.3.c.

The only motor operated valve breaker which is open and tagged at this point is that for SI-MOV-1.

Information on breaker location, control and indication is presented in Answers #I.3.c. and I.3.e.

The following questions pertain to component or system tests performed during cold shutdown conditions which could lead to Appendix G violations.

I.4.a. QUESTION: What components or system that could cause a pressure transient are routinely tested while in a cold shutdown condition?

ANSWER: The main coolant charging pumps are tested on the basis of one pump each week.

I.4.b. QUESTION: What extra measures are taken to prevent an overpressure event during these tests?

ANSWER: The pumps are not tested while in a water solid condition. In addition, pump capacity is 33 gpm maximum and any pressure transient, if it did occur, would be limited by the two shutdown cooling system relief valves.

I.5 QUESTION: You briefly describe a proposed alarm in Appendix B, on page B-3. With regard to this proposed alarm, furnish the following information:

a. Your method to provide the alarm, and the implementation schedule.

ANSWER: The bistable/relay unit formerly used to operate the SIS valves associated with the main coolant pressure channel of the reactor protection system will be utilized. This modification will be installed during the Core XIII refueling outage scheduled for June 1977.

b. A synopsis of the system modifications that are necessary.

ANSWER: A new pressure channel is to be installed that will sense the main coolant pressure. The sensing line is the same as that used by the main coolant pressure channel of the reactor protection system. The new channel will consist of a power supply, 0-3000 psig pressure transmitter, dual setpoint trip device, auxiliary relay and a strip chart recorder. One setpoint of the trip device will be connected to a window on panalarm N-C. This alarm will actuate at 450 psig decreasing main coolant system pressure and will be used to signal the operator to activate the key operated interlock discussed below.

The other setpoint of the trip device will be adjusted to operate, through the auxiliary relay, the pressurizer solenoid operated relief valve.

A key operated interlock switch will also be installed. The contacts of this interlock will be connected to the pressurizer solenoid relief valve and the main coolant overpressurization alarm circuitry.

c. The alarm setpoint, mode of annunciation and sensor.

ANSWER: The bistable trip-on point that informs the operator of a transient will be set at 400 psig increasing; and the trip device setpoint that operates the pressurizer solenoid relief valve will be set to operate at 500 psig. The relay associated with the bistable will operate a window on panalarm N-C on the Main Control Board. The sensing channel for this alarm consist of a Bailey Meter Company KIX pressure transmitter, Westinghouse 927D 658 GR7 Linear Amplifier, Westinghouse 927D633 GR6 bistable and a Westinghouse 443D 821 G6 Relay Panel.

d. How you ensure that the alarm is available and operating properly during all water-solid operations and how you minimize its down-time for all other cold shutdown conditions.

ANSWER: The key operated switch will be utilized to ensure that a circuit will exist for the operation of the alarm. This, together with the panalarm window being lit informing the operator that an overpressurization transient could occur will indicate the system is operating properly. Also calibration procedures will include precautions prohibiting isolation when an overpressurization condition could occur. These design features and calibration procedures together with administrative controls will ensure availability of the alarm during all water-solid conditions.

I.6. QUESTION: The use of the SCS code safety valves as overpressure protection devices is discussed in your submittal. To assist us in evaluating your proposal, supply the following information:

a. A diagram of your SCS showing the arrangement on the code safety valves.

ANSWER: A diagram of the shutdown cooling system showing the arrangement of the code safety valves and system isolation valves is included as Attachment D.

b. SCS design pressure.

ANSWER: The shutdown cooling system is designed for 2300 psig up to and including SC-MOV-551 and SC-MOV-552. The remainder of the system is designed for 425 psig.

c. A description of the system isolation valves and their arrangement (e.g., number and configuration of valves installed, and pneumatic or motor operated).

ANSWER: The four system isolation valves (SC-MOV-551, SC-MOV-552, SC-MOV-553 and SC-MOV-554) are six inch, Limitorque motor operated, stainless steel gate valves.

d. Interlocks, interlock setpoints, and alarms associated with each isolation valve.

ANSWER: The system isolation valves mentioned in I.6.c. can only be operated by inserting a key into the respective control switch. Once the key is removed, the control switch cannot be operated and hence, the valve cannot be electrically operated. The keys are kept under the administrative control of the duty Shift Supervisor. There are no alarms associated with the shutdown cooling system isolation valves.

e. Nominal stroke time of isolation valves.

ANSWER: The nominal stroke time for each shutdown cooling system isolation valve is approximately 33 seconds in each direction.

f. All pressure alarms, setpoints and associated annunciation for the system.

ANSWER: There are no pressure alarms associated with the shutdown cooling system.

The following question pertains to operating the cooling charging pumps.

I.7. QUESTION: Based on your December 1, 1976 submittal, we assume that the SIS high pressure pumps and the coolant charging pumps are not the same. Describe the methods you use to prevent inadvertent pressure transients from the latter.

ANSWER: The SIS high pressure pumps and coolant charging pumps are not the same. An inadvertent pressure transient would be limited by the fact that shutdown cooling safety valve capacity exceeds charging pump capacity. Operation of the charging pumps while in a water solid mode is only for the purpose of controlling pressure and by a man stationed solely to monitor and control pressure.

The following question pertains to increasing pressurizer level during plant startup.

I.8 QUESTION: After admitting filtered air at 80 psig to the pressurizer, the water level is increased so that RCS pressure is sufficient for the main coolant pump (MCP) jog procedure (page A-4 of your submittal). A pressure transient is considered possible while raising the pressurizer level. Describe the steps you take to ensure this does not occur.

ANSWER: The pressure transient, if it developed, would be limited by the shutdown cooling safety valves, which are still in service, and have a greater capacity than the charging pumps. Additionally, during the next refueling, the plant is planning to modify the pressurizer solenoid relief valve so that during cold shutdown conditions it can be set for 500 psig.

II.1.a. QUESTION: On page B-1 you state that each SCS safety valve has the capacity to relieve 101 gpm of 400°F water at about 467 psig. Please address the following questions:

Provide an analysis which estimates the combined relief rate assuming the fluid is at 100°F, 200°F and 300 °F for a range of pressure above the setpoint.

ANSWER: The results of the requested analysis are presented in the table below. Description of the analysis procedure is contained in the answer to question II.1.b. below.

Table II.1.a

Pressure	Combined Capacity of both SCS safety valves (GPM)		
psig	T=100°F	T=200°F	T=300°F
468 (10%)	172	174	178
532 (25%)	256	259	264

II.1.b. QUESTION: The effects of flashing and backpressure on safety valve discharge rate should be determined by your analysis. We request that the results of your analyses be provided, even if a significant reduction in discharge capacity is not found. Furnish your time schedule for completing and submitting this analysis.

ANSWER: The procedure for calculating the relief rates of Table II.2.a. are based upon available data on safety valve capacity, consideration of backpressure buildup in the safety valve discharge piping, and in the discharge receiving tank.

At present, the extent to which flashing within the valve occurs or is accounted for by the manufacturer in determination of safety valve capacity, is unknown. A detailed inquiry, aimed at clarifying this point, has been sent to the valve manufacturer; and we are awaiting his response. In the meantime, we are utilizing the following relation, taken from the manufacturers catalogue, to compute safety valve capacity:

$$\text{Capacity (gpm)} = 27.2(C_A)(K_{SG})(K_{BL})(A)\sqrt{P-Pb}$$

where:

C_A = accumulation factor

= 1.0 for 25% accumulation

= 0.6 for 10% accumulation

K_{SG} = specific gravity correction factor (1.0)

K_{BL} = backpressure flow factor (1.0)

A = orifice area (in^2)

P = set pressure (425 psig)

Pb = backpressure (psig)

Backpressure imposed at the discharge of the safety valve depends upon pressure in the receiving tank and flow losses in the discharge piping from the valve to the receiver tank. The receiver tank is the low pressure surge tank (LPST). Its operating pressure is maintained below 25 psig by means of an automatic vent valve, and its maximum pressure is limited to

75 psig by six safety valves which relieve back to the vapor container. This analysis conservatively assumes a constant LPST pressure of 75 psig.

In treating flow losses in the safety valves' discharge line, the actual pipe configuration is simplified using standard methods outlined in Crane Co. Technical Paper #410 and the Hydraulic Institute Pipe Friction Manual. Head losses in the equivalent length of discharge pipe are computed based upon previously calculated flow through the safety valve. The computed head losses in the discharge line are added to low pressure surge tank pressure (75 psig) to arrive at total backpressure at the safety valve discharge.

To arrive at the actual safety valve capacity, an iterative approach based on trial and error was used. Safety valve relief rate (capacity) is initially computed from the above formula using LPST pressure (75 psig) as the sole component of backpressure on the valve. This results in a maximum (although incorrect) value for valve capacity. Using this first calculated value of relief valve flow rate, head loss in the discharge line is calculated. This pressure drop, combined with LPST constant pressure is then used as the corrected backpressure value in the next trial calculation of relief valve capacity. This iterative process produces a series of trial results which rapidly converge on the value of relief valve capacity which is compatible or "balanced" with the actual piping losses. These final or "converged" values are the values reported in Table II.1.a.

The artificial imposition of a constant 75 psig pressure in the LPST is discussed further in the answer to Question II.2.b. Since 75 psig is in excess of the saturation pressure for 300°F water, the calculation of relief valve capacity need not consider directly the complicated effects of two phased flow in the discharge piping. Our assumption of a constant 75 psig pressure in the LPST artificially reduces the calculated relief valve capacity because it is a function of the pressure difference across the valve. We are confident that this approach yields results which are conservative with respect to the actual situation in which two phase flow might occur.

II.2.a. QUESTION: On page B-1, you state that the discharge of the shutdown cooling system safety valves is directed to a terminal tank. Regarding this arrangement, address the following:

a. Does the pressurizer relief valve relieve to the same place?

ANSWER: Fluid discharged from the shutdown cooling system safety valves can be routed by means of a three way, diverting valve to either the low pressure surge tank (LPST) or the primary drain collecting tank. When the shutdown cooling system is in service, the three way valve is aligned to direct any discharge to the LPST. The pressurizer relief valve also discharges to the LPST.

II.2.b. QUESTION: Since the SCS safety valves and the pressurizer relief valve may be open during a pressure transient, simultaneous discharge is possible. If the terminal tank is common to both relief valves, what is the possibility of backpressure from one discharge effecting the flow rate from the other?

ANSWER: In the circumstance established by the question, the LPST would be the common relief tank for both the pressurizer relief valve and the SCS safety valves. The only effect of one discharge upon the other would be an increase in internal pressure of the LPST during the duration of the discharge. Such a pressure increase would be the combined result of a level increase and accumulation of uncondensed steam in the LPST during the period of the discharge. All discharges from the SCS safety and pressurizer relief valves enter the LPST below normal water level and mix with its contents through an eductor and sparger arrangement. LPST initial temperature and pressure are typically below 150°F and 25 psig during the latter stages of plant cooldown or early stages of plant heatup. Therefore the LPST is ready to quench any steam entering the LPST during a discharge. If LPST pressure were to reach 75 psig during the discharge, six high capacity safety valves will function to limit LPST pressure to essentially 75 psig. The calculation described in the answer to Question II.1.b. conservatively assumes LPST pressure constant at 75 psig.

II.3. QUESTION: Provide prints of the existing and proposed circuitry used to operate the solenoid on the pressurizer relief valve. These diagrams should enable us to trace signals from the detector to the solenoid.

ANSWER: The following attached sketches describe the existing and proposed circuitry.

1. Yankee Rowe Low Temperature Overpressurization Transient Protection System

Sketches 1, 2 and 3

II.4. QUESTION: It is the staff's position that the probability of a LOCA not be allowed to increase significantly because of design modifications made to protect against overpressurization at low temperatures. You propose to replace your existing pressurizer relief valve with one of higher capacity. Further, the proposed dual pressure setpoint potentially introduces additional failure modes that could cause the valve to open while the RCS is at normal operating pressure. Describe the features of your proposed design (such as single failure proof circuitry and interlocks) that would minimize the probability of inadvertent opening of the relief valve.

ANSWER: The primary change to be implemented at Yankee Rowe consists of adding a low pressure setpoint feature to the actuation circuitry for the existing pressurizer solenoid relief valve. This low setpoint (approximately 500 psi) for low temperature operation will, via standard operating procedures, be activated during required stages of RCS low temperature operation. The monitoring circuitry will consist of a main coolant pressure transmitter, an adjustable dual contact output bistable, a strip chart recorder and the required circuitry power supplies. The pressure transmitter will be located in the vapor container. The pressure taps for the transmitter will be on the cold leg of main coolant loop #1 such that it cannot be isolated from the reactor vessel by closure of the cold leg loop isolation valve. This tap location will ensure monitoring of actual reactor vessel pressure during all stages of plant operation. Required isolation, drain and test connections will be provided on pressure sensing lines. The power supply and trip bistable will be located inside the main control board. The recorder will be mounted on the nuclear section of the main control board and will provide a continuous record and indication of reactor vessel pressure. One of the dual trip device contacts will be set to actuate at 500 psig increasing and will be wired to the relief valve actuatiin circuit via the permissive keylock switch. The keylock switch will be located on the front part of the nuclear section of the MCB. The second dual trip device contact will be set to actuate at approximately 450 psig decreasing and will provide alarm notification to the operator to activate the low temperature overpressurization system during low temperature plant operation. An existing bistable located in the MCB will be set to actuate at 400 psi increasing and will be wired via the permissive keylock switch to a MCB annunciator window to provide an alarm output to notify operators of an impending low temperature overpressure condition. This alarm bistable is set below the relief valve trip bistable setpoint to allow the operator to initiate corrective action to avert a possible low temperature overpressure condition. The addition of the low setpoint circuitry does not effect the existing circuitry for the 2500 psig setpoint and will not introduce additional failure modes to the existing system. The 500 psig circuitry incorporating the key-locked switch, will be under the administrative control of the control room operator. Plant operating procedures will incorporate the use of the key-locked switch and will address proper system operation to minimize the probability of inadvertent opening of the relief valve.

II.5. <u>QUESTION</u>: Discuss the feasibility of including an alarm that would warn the operator to actuate the low pressure setpoint on the pressurizer relief valve, to assure its availability during RCS low temperature operations.

<u>ANSWER</u>: As discussed in the answer to Question II-4, an alarm will be made available which will warn the operator to actuate the low pressure setpoint system on the pressurizer relief valve.

II.6 <u>QUESTION</u>: The use of an extra dedicated operator for RCS pressure monitoring during water-solid operations is discussed on pages A-2 and B-3. Describe the indications, alarms and warning devices available to this operator that guarantee his awareness of a pressure transient in progress, and indicate those analyses in which you take credit for his action.

<u>ANSWER</u>: Indication of main coolant pressure available to the operator during water-solid conditions consists of the main coolant pressure indicators on the main control board. The response to questions I.5.b. and II.4 describe the additional indications to be installed during the forthcoming refueling outage.

The dedicated operator currently required by plant operating procedures during water-solid conditions is expected to open the pressurizer solenoid operated relief valve if necessary to prevent exceeding the Appendix G pressure limits. This is a temporary measure instituted to provide immediate availability of the pressurizer relief valve as a pressure transient mitigating device during solid conditions. Once the design change providing a low pressure setpoint feature for this relief valve is implemented, the temporary requirement for this dedicated operator can be removed.

The pressurizer relief valve is the primary means of mitigating an overpressurization event, should one occur. However, as described in the response to Question No. II.7.b., the shutdown cooling system safety valves, a pressurizer steam volume and operator action after ten minutes all serve variously as backup measures depending upon the specific event.

Therefore, it can be stated that reliance on this special, dedicated operator is not required to mitigate the consequences of any overpressurization event. However, until the low pressure setpoint feature is implemented, reliance on this operator responding within ten minutes of an event is required to meet the suggested "single failure" criteria.

II.7.a. QUESTION: It is not clear from your discussion of design criteria, (page B-3 to B-5) whether the criteria are being applied to your present or future pressure protection system. To clarify this, address the following:

In discussing the operator action criteria, using an operator to take corrective action within ten (10) minutes is described. Will this be needed when your dual setpoint feature is installed? What operator action design criteria will be applied for your final design modification?

ANSWER: Our intention is to meet the suggested design criteria to the extent practicable with both the presently installed and planned replacement pressurizer relief valves. The answer to the previous question (II.6) indicates that our reliance on the proper response of the special, dedicated operator is a temporary requirement which immediately makes available the existing pressurizer relief valve as a pressure transient mitigating device. The installation of a low pressure automatic setpoint feature to the solenoid for this valve will preclude the requirement for the special, dedicated operator. The only operator action criterion planned for the final design configuration is the suggested ten minute response time delay criterion. However, we believe that the principle of a special, dedicated operator with very limited responsibilities being able to properly respond within the ten minute period is a sound and reasonable concept. In the event that future developments regarding reactor vessel overpressurization protection indicate the need for further protection features, we will consider this principle as a viable alternative to some expensive design change.

II.7.b. QUESTION: The single failure criterion discussed on page B-4 states that below 300°F, three relief valves are available. For RCS temperatures between 300°F and 360°F, operator action after a response delay of ten minutes provides pressure protection. The RCS can be fully pressurized above 360°F. Will operator action still be required in the 300°F to 360°F range when the dual setpoint, higher capacity pressurizer relief is installed? What single failure criteria will you use then?

ANSWER: Preliminary note: See Answer # III.2. The above quoted 360°F value has been revised to 324°F.

Below 300°F, the shutdown cooling system safety valves are available. Therefore, these valves and the pressurizer relief valve are available as pressure transient limiting devices. As described in the answer to Question No. II.9, the SCS safety valves have sufficient capacity to be considered as 100 percent backup for both the present and planned pressurizer relief valves. Therefore, the suggested single failure criterion is met at temperatures below 300°F without operator action.(1)

Above 300°F, the SCS safety valves are isolated from the main coolant system and therefore unavailable to limit a pressure transient. However, the main coolant system is not solid at these temperatures and a pressurizer steam volume of $\geq$ 198 cubic feet is available. For all postulated events that could lead to overpressurization at these temperatures, the pressurizer steam volume limits pressure buildup over the first ten minutes to a value less than the Appendix G limits. Therefore, in this temperature range, operator action beyond ten minutes is an effective backup to the pressurizer relief valve low setpoint in limiting main coolant pressure. Therefore, the suggested single failure criterion can be met for all conditions requiring reactor vessel overpressure protection. Table II.7.b. summarizes the above discussion.

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(1) Except that special dedicated operator action is required until the low pressure setpoint feature is implemented.

Table II.7.b.

	Protection Means	
MCS Temperature ^{o}F	Primary	Backup
≤ 300	Pressurizer Relief Valve	SCS Safety Valves
$300 < T \leq 324$	Pressurizer Relief Valve	Operator Action a (t+10) minutes

II.7.c. QUESTION: Do the Testab'lity, Seismic Considerations and IEEE 279 sections of Appendix B pertain to the system as it now exists or as it will exist once the proposed features are installed (e.g., dual setpoint, high capacity relief)?

ANSWER: The testability, seismic, and IEEE-279 sections of Appendix B pertain to the system which will exist once the proposed features are installed.

II.8. QUEST'ON: We do not understand your statements at the bottom of page B-3 and the top of page B-4. In these statements you are describing how you take credit for operator action within ten (10) minutes, and that this action is fully redundant to the SCS reliefs or operator action at ten (10) minutes. To clarify our understanding of these statements, address the following:

a. If action at ten (10) minutes prevents overpressurizations, then why is action required before this, (i.e., why is it necessary to deviate from the staff's operator action criterion)?

b. With regard to Appendix C in which you evaluate potential overpressure causing events, several of these require operator action to prevent RCS overpressurizations. However, in each of these cases, the operator action took place ten (10) minutes after the event despite your stated need for action in less time (page B-3). Clarify this apparent discrepancy.

ANSWER: Shortly after NRC's letter of August 11, 1976 expressed concern about reactor vessel overpressurization the Superintendent of the Yankee Rowe plant established the temporary requirement for the special, dedicated operator to be stationed at the main control board during water-solid conditions. At that time, as now, the pressurizer relief valve was not equipped with a low pressure setpoint feature. The primary purpose of the special, dedicated operator, therefore, was to immediately make available the relief capability of the pressurizer relief valve in the unlikely event of an overpressurization transient. Instead of waiting for the implementation of an undefined, automatic design feature, this prudent action provided immediate, assured protection during subsequent plant conditions requiring such protection. This action was taken swiftly despite the fact that plant operating procedures were already extremely conservative and cautious regarding water-solid conditions and in light of the fact that not a single overpressurization event is known to have occurred at the Yankee Rowe plant in its entire, long operating history.

This temporary requirement for a dedicated operator was established before all analyses were completed of the various postulated pressure transient. Whether or not operator action within the ten minute period was required to either protect the plant or meet the to-be-suggested single failure criterion was not known at that time. By having the operator available, the plant had the protection available until such time as it was shown to be unnecessary. Since then, review and analyses of various pressure transient events have been conducted and reported in our original submittal and in the answers to these questions. Reliance on operator action within ten minutes has been shown to be unnecessary except to operate the pressurizer relief valve manually until the automatic, low pressure setpoint feature is installed in the next few months.

We hope this clarifies any confusion that may have existed regarding why the dedicated operator requirement was established. We think our action was prudent, conservative, and timely and stands as testimony to Yankee's positive responsiveness to valid NRC concerns.

II.9. QUESTION: On page B-4, in Section B you state that two of the three relief valves that are available below 300°F are sufficient to keep transient RCS pressures in the worst-case event to less than vessel limits. You further state that the new high capacity pressurizer relief valve will be fully redundant to both of the SCS safety valves. You also stated, previously, that each SCS safety valve can relieve 101 gpm at 467 psig (Appendix B, page B-1). From

Figure A-1 on page C-23, the replacement pressurizer relief valve capacity does not reach 202 gpm until system pressure is about 500 psig. Explain this inconsistency. Consider future operation with more restrictive Appendix G limits as vessel irradiation increases.

ANSWER: A comparison of the relief rates of the pressurizer relief valve (both existing and new) and the two shutdown cooling safety valves (taken together) should help clarify the apparent inconsistency. The following table includes values from Table II.1.a. (response to a previous question) and data extracted from Figure A-1 of Appendix C to the original submittal (page C-23).

Table II.9

	Capacity gpm		
System Pressure	Existing Pressurizer Valve(1)	New Pres. Valve(1)	SCS Valves @300°F
467 psig	136	178	178
532 psig	160	238	264

The above table shows that the shutdown cooling safety valves have a calculated capacity at least equal to that of the new and existing pressurizer relief valves. The transient analyses of the postulated reactor coolant pump full flow initiation event contained in Appendix C to the original submittal shows that the single pressurizer relief valve is sufficient in capacity to limit the transient pressure to within acceptable limits. Since the pressurizer relief valve alone was the basis for the analysis, our statement on page B-4 should have been: "The shutdown cooling safety valves possess sufficient relief capability to be fully redundant to either the existing or the new pressurizer relief valve."

II.10 QUESTION: The single failure criteria we specified at our November 3 meeting, and as summarized in the meeting summary (copy attached) require that following the initiating event (failure) the pressure protection

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(1) at 440°F, 500 psig.

system be designed to protect the RCS with a single (additional) failure (either equipment or operator) once the pressure transient is in progress. It is not evident from your submittal whether your system is designed in accordance with this criteria. Provide additional discussion on your system's single failure criteria, and what modifications in your final design would be needed to meet the acceptance criteria described above.

ANSWER: First, we would like to emphasize our understanding that the single failure criteria and all other design and operator action criteria discussed at the November 3, 1976 meeting were and remain "suggested" criteria. We feel that your apparent trend toward treating all equipment which could either cause or mitigate an overpressurization event as full safety-grade equipment may be unwarranted considering the potential cost of design changes necessary to meet these various suggested criteria. Since low temperature overpressurization can never occur at power, equipment designed or modified to prevent or mitigate its consequences should not necessarily have to be designed to meet all criteria imposed on ECCS systems.

In view of the above, and because we are committed to implementing all reasonable steps to protect against ever having an overpressurization event at Yankee Rowe, we have attempted to meet all suggested criteria to the extent feasible. There is only one pressurizer solenoid-operated relief valve installed at Yankee Rowe. Therefore a simple mechanical failure of the valve itself could be postulated. As explained in the original submittal and the response to Question No. II.7.b., the single failure criteria relative to mitigation of an event, can be met at Yankee Rowe primarily by the principle of diverse methods.

II.11. QUESTION: Paragraph C, page B-4 discusses the testability of your pressure protection components. Provide further explanation as to why the "total operability" of the dual setpoint pressurizer relief valve cannot be determined.

ANSWER: The pressurizer relief valve is a solenoid-operated, pilot-actuated valve. Electrical impulse to the solenoid positions a pilot which opens a vent path which, in turn, permits upstream fluid pressure to open the valve. An indicating light on the main control board shows whether or not the solenoid is energized but does not positively indicate whether the valve physically opens or not. During the pre-cooldown test, the upstream isolation valve is closed and the solenoid energized. Since the relief valve is isolated, no changes in pressurizer pressure or downstream temperature will occur. Therefore, "total operability" of the valve cannot be verified by an in-place test.

II.12. QUESTION: As we stated in our November 3 meeting, the electrical components of the pressure relief system should be designed to meet the requirements of IEEE 279, or you should provide the basis for any deviations. Paragraph E page B-5 discusses IEEE 279 requirements but lacks sufficient justification for the deviations. Provide your basis for not meeting the requirement specified in IEEE 279. Include any prints or diagrams necessary to your explanation. Will the additional instrumentation and electrical equipment you have proposed meet IEEE 279 requirements as well as Class IE criteria?

ANSWER: The design of the Pressurizer Relief Valve System does not meet the requirements of the IEEE 279 standard. The mechanical equipment will be purchased for Safety Class I application. The Quality Assurance requirements which would be imposed on the purchase of electrical equipment and instrumentation designed to the requirements of the IEEE 279 standard will be imposed on the purchase of electrical equipment and instrumentation which will be used in the Pressurizer Relief Valve Control System.

III.1.a. QUESTION: Appendix C discusses your evaluation of postulated events which could cause reactor vessel overpressurization. Respond to the following:

In all postulated events, except the Main coolant pump (MCP) start, you assume that the presently installed equipment is available for pressure protection (e.g., SCS safety valves and operator control of pressurizer relief valve). In the analysis of the MCP start transient, you assume the availability of only the existing pressurizer relief valve with the dual setpoint feature, taking no credit for the two (2) SCS safety valves (425 psig, 101 gpm each) which are assumed operable for all other transients. We do not understand why an analysis was not performed assuming the higher capacity SCS safety valves were available for pressure protection. Please explain this assumption.

ANSWER: In all postulated events we assume the availability of protective features consistent with Table II.7.b included with the response to Question No. II.7.b.

The main coolant system full flow initiation transient (not necessarily a pump start) is no exception. The analysis considered only the calculated relief capacity of the pressurizer relief valve in order to ascertain whether or not this valve alone could limit transient pressure to within acceptable limits. Figures B-1 and B-2 of the original submittal demonstrate that the single pressurizer relief valve has sufficient capacity to maintain transient pressure to within acceptable limits. Therefore, since the SCS safety valves' capacity is equal to or greater than that of the pressurizer relief valve (new or existing), we have established that the SCS safety valves are fully redundant to the pressurizer relief valve.

III.1.b. QUESTION: You have not considered the inadvertent ECCS operation or the loss of shutdown cooling heat capacity transients as plausible events due to your procedural restrictions. However, the reactor coolant flow initiation transient is analyzed in detail, even though procedural restrictions do not allow MCP starts unless an air or steam bubble exists in the pressurizer (page C-11) and at all other times, the MCP breakers are withdrawn (page A-2). Explain in detail why you have selected the MCP start transient as the event requiring the most detailed study, and not the inadvertent ECCS operation or the loss of SCS. Explain the difference in your procedural restrictions that allow the MCP start to be more likely than the other two transients.

ANSWER: We have analyzed the following postulated events regardless of their potential or probability for occurrence:

a. MCP full flow initiation.

b. Inadvertent ECCS initiation.

c. Charging/bleed (letdown) flow mismatch.

d. Pressurizer heater-induced expansion.

e. Loss of residual heat removal capacity.

The fact that the main coolant full flow initiation transient was selected for a time-dependent transient analysis should not be construed to indicate that it is either the most potentially severe or the most likely to occur of the events considered. It may actually be either, but we did not attempt to ascertain this. Instead, we investigated the impact of each potential overpressurization event that could be initiated by a single equipment failure or operator error. This investigation led to definition of the above listed events. At this point we did two things:

1. Took measures to prevent the occurrence of each of these events.

2. Undertook an analysis of each of these events.

The analysis of each event attempted to determine whether or not plant equipment and/or operator action could adequately protect against that event regardless of whether or not it could occur. Most of the transients were slow and all transients except the main coolant flow initiation transient could be adequately analyzed by means of hand calculations. The primary reason for conducting a time dependent transient analysis on the main coolant flow initiation transient is that it is a short duration transient dependent on many variables. Hand calculations could not have produced a sufficiently realistic yet conservative prediction of peak transient pressure.

III.1.c. QUESTION: On page C-13 you state that further reviews of your pressure protection system will be performed as vessel irradiation alters the Appendix G pressure-temperature limitations. Furnish an estimated schedule for your future reviews and associated submittals to the staff. Indicate if your high capacity pressurizer relief valve has been sized on the basis of anticipated vessel irradiation effects on Appendix G limits and the applicable irradiation levels assumed.

ANSWER: A revised Appendix G pressure-temperature curve is prepared and applied to each new core. Therefore, a review of the adequacy of the pressure protection system will be conducted prior to each refueling outage.

The increased capacity of the planned replacement pressurizer relief valve was determined prior to development of the overpressurization issue. The overpressurization question did not determine nor has it altered the sizing of this planned replacement valve.

III.2 QUESTION: On page C-4, you state that the maximum allowable pressure at 300°F is about 1300 psig, and on page C-2 you indicate that the RCS may be fully pressurized when above 360°F. Furnish a plot of your allowable pressure-temperature curves showing the Appendix G limits, as a function of irradiation.

ANSWER: Figure III.2 is representative of the applicable

Appendix G limits for heatup and cooldown. This figure is based upon Figures 3.4-4 and 3.4-5 of the current Technical Specifications. These pressure-temperature limits are revised each refueling outage to account for vessel cumulative irradiation.

The 1300 psig and 360°F limit quoted above, should be 1800 psig and 324°F respectively in accordance with the Figure provided. The 1300 psig and 360°F limits were based upon the assumption that Technical Specifications Figures 3.4-2 and 3.4-3 applied to reactor vessel overpressurization protection. In light of the Technical Specifications bases, we now feel that Figures 3.4-4 and 3.4-5 are the more appropriate limits for such low probability events.

III.3 <u>QUESTION:</u> On page C-2, you conclude that further protection against an inadvertent ECCS actuation is not required due to your procedural controls. We have reviewed your procedural measures described in Appendix A and on page C-2.

Since you close SI header isolation valves and disable SI pumps, inadvertent injection is definitely less likely. However, we will require that you demonstrate adequate overpressure protection considering all potential initiating events. Accordingly, address the following:

a. Perform a RCS transient pressure analysis assuming a non water-solid pressurizer and an inadvertent injection from a single ECCS train. State your initial conditions.

b. Since the RCS is made water solid at around 180 $^{\circ}$F on a system cooldown (Appendix A), and the third ECCS train is tagged out when the RCS temperature is $\leq$ 200°F, perform the same analysis as above assuming a water-solid system. (Assume a RCS temperature of about 180°F).

c. How sensitive is the predicted RCS pressure response in the above analyses to the initial RCS temperature and pressure (assuming accumulation effects on relief value performance)?

<u>ANSWER:</u> Consistent with the requirements of Technical Specifications, the following action has been taken on a plant cooldown when temperature and pressure are less than 3[illegible]0°F and 1000 psig, respectively:

a. Automatic safety injection has been blocked.

b. The control switches for <u>all</u> ECCS pumps have been placed in the Trip-Pullout position.

c. Motors for two trains of ECCS pumps have been made electrically inoperable by racking out, locking and tagging their circuit breakers.

d. The accumulator isolation valve is closed made and tagged electrically inoperable.

e. One motor operated valve in the injection flow path to each main coolant loop is closed (but remains electrically operable).

Based upon the above steps, it is concluded that at least <u>three</u> consecutive, single-equipment, <u>spurious</u>, <u>active</u> failures and/or single operator errors would have to occur in order to activate a single ECCS train under these conditions. Two possible activation sequences are listed below.

<u>Sequence 1</u>:

1. LPSI pump starts.

2. HPSI pump starts.

3. A closed MOV leading to a main coolant loop opens.

<u>Sequence 2</u>:

1. Place CS for HPSI pump in Auto.

2. Place CS for LPSI pump in Auto.

3. Manually initiate safety injection or remove block on automatic safety injection.

Furthermore, at least <u>two</u> single equipment failures and/or operator errors would be required in order to initiate flow to the reactor vessel from one pump of a single ECCS train.

It is therefore, concluded that procedural controls adequately prevent inadvertent initiation of flow to the reactor vessel by either a single pump or a complete train of ECCS.

Based upon the above conclusions, a transient analysis of this event seems unwarranted and has not been performed. However, a qualitative evaluation of this event has been conducted and is presented below.

The maximum attainable pressure in this postulated event is dependent on the available relief valve capacity and the particular design features of the Yankee Rowe ECCS components and piping. The head-flow characteristics of each ECCS pump have been provided in the response to Question #1.3.a. From these curves the following data is taken:

Table III.3

Pump	Shutoff Head (psi)	Maximum Flow (gpm)
LPSI	700	1100
HPSI	850	220

Figure III.3 is a simplified flow diagram of a single ECCS train. This drawing illustrates the series-parallel flow paths provided for the LPSI and HPSI pumps. This arrangement provides series flow (through the LPSI then HPSI pump) when main coolant pressure is high; and parallel flow which effectively bypasses the HPSI pump when system pressure is low. This inherent characteristic of each ECCS pump train comes into play in the postulated event under consideration.

The following sequence would occur in the event of an inadvertent initiation of a single ECCS train while in the water-solid condition:

a. One LPSI and HPSI pump starts and a flow path to at least one main coolant loop becomes available.

b. The HPSI pump rapidly increases system pressure to the set pressure of the pressurizer relief valve and the SCS safety valves. Maximum system pressure developed by the HPSI pump is approximately 850 psig.

c. The LPSI pump (being a larger pump) accelerates more slowly to full RPM. As the LPSI pump accelerates to full RPM, system pressure will increase beyond 850 psig as the discharge of the LPSI pump feeds the suction of the HPSI pump.

d. If this event occurred at a temperature above 300 degrees, when the SCS safety valves are unavailable, and the pressurizer relief valve failed to operate, system pressure, without operator action, could not exceed approximately 1550 psig. At 300°F, the applicable Appendix G pressure limit (based upon cooldown Technical Specifications Figure 3.4-5) is approximately 1800 psig. Therefore, in this event, the Appendix G limits would not be exceeded.

e. If this event occurred at a system temperature between 200°F and 300°F, when the SCS safety valves are available, and the pressurizer relief valve failed to operate, system pressure, without operator action, could not exceed approximately 700 psig, the shutoff head of the LPSI pump. This is because the relief capacity available exceeds the design flow rate of the HPSI pump. Consequently, the HPSI pump develops no appreciable head. At 200 °F, the applicable Appendix G pressure limit (based upon Technical Specifications Figure 3.4-5) is approximately 1000 psig. Therefore, in this event, the Appendix G limit is not exceeded.

f. If this event occurred with a steam bubble in the pressurizer, the end result would be the same. Initially, LPSI pump flow rate would be very high - approximately 1100 gpm - the design flow rate - until the steam volume was pumped solid in approximately 1.5 minutes. Once solid, the final system conditions would be the same as described above.

The inadvertent initiation of ECCS flow to the vessel from a single pump in a single ECCS train could not pressurize the system in excess of 850 psig. As stated above, this does not exceed the Appendix G limit.

From the above discussion, it is concluded that, despite the unrealistic assumption that an inadvertent initiation of one train of ECCS pumps could occur, such an event cannot increase pressure beyond the Appendix G limits assuming a failure of the pressurizer relief valve to open on signal.

III.4. <u>QUESTION:</u> Describe the procedural or equipment limitations that ensure a minimum pressurizer steam volume of $\geq$200 cubic feet, as you describe on page C-3.

<u>ANSWER:</u> At all main coolant temperatures above 300°F (when the shutdown cooling system is isolated), a pressurizer steam volume of $\geq$198 cubic feet is maintained. Normal pressurizer water level of 120 inches narrow range is specified by plant operating procedures and maintained automatically by the variable speed, positive displacement charging pumps. This normal

pressurizer water level provides a steam volume of 205 cubic feet. If level were to increase to 129 inches, the charging pumps would be tripped. At this high level point, pressurizer steam volume is 198 cubic feet.

III.5 QUESTION: Two cases are discussed in the charging without bleed flow transient. In Case B, you indicate that an analysis of this event was performed. Provide the details of this analysis. As a minimum, furnish the following information:

a. Description of system model

b. Initial conditions and assumptions

c. Plot of RCS pressure vs. time

d. Sensitivity of predicted response to initial conditions.

ANSWER: A transient analysis of this case was not performed. The analysis consisted of a hand calculation (with conservative simplifying assumptions) which determined the pressure increase in the pressurizer over a ten minute period resulting from the continuous charging of 100 gpm. Pressurizer level increases steadily during the ten minute period, but a steam volume is always present. The thermodynamic behavior of the steam volume as it is being compressed limits the pressure rise to the order of 100 to 200 psi.

III.6. QUESTION: On page C-4, you briefly describe an "operational pressure limit" (OPL) that precludes vessel overpressurization in Case B of the charging without bleed flow transient. Please furnish additional information on this OPL, indicating when it is used, and how it precludes vessel overpressurization for this event.

ANSWER: Normal plant heatup and cooldown procedures define an upper limit on main coolant pressure as a function of temperature that is more limiting than the Appendix G pressure-temperature curves. This operational limit curve is based upon operating restrictions inherent to the canned-rotor type coolant pumps installed at the Yankee Rowe plant. As an example, at 300°F, the Appendix G curve limits pressure to about 1800 psig. The "operational limit" at 300°F is about 500 psig. The "margin of safety" at 300°F, then, is 1300 psig. Therefore, since an incident of continuous charging at the unrealistically high rate of 100 gpm will increase pressure only 100-200 psig in ten minutes, the 1300 psig safety margin is more than enough to prevent exceeding the Appendix G pressure limit. The operational limit is illustrated in Figure III.2.

III.7 QUESTION: In your discussion of the pressurizer heater operation without bleed flow, on page C-5, you state:

> "It is assumed throughout the discussion that the single equipment failure or operator error is that which causes isolation of the bleed path. No further failures or errors occur."

This assumption is not consistent with single failure criteria specified in our November 3, 1977 meeting and as repeated in the meeting summary:

> "Single Failure Criteria - The pressure protection system should be designed to protect the vessel given a single failure in addition to a failure that initiates the pressure transient."

If this criteria cannot be met, provide sufficient justification for not doing so.

ANSWER: What we mean by the statement on page C-5 quoted above, is that we are not considering multiple failures in the cause of the postulated event. In other words, we are not considering inadvertent isolation of the bleed path together with some other equipment failure or operation error which could compound the severity of the incident. However, as indicated in the answer to question II.7.b., the additional single failure in the mitigating system proposed by the suggested single failure criterion has been accounted for. Therefore, we feel that our analysis of this incident meets the suggested criterion.

III.8 QUESTION: In your discussion of Cases A, B, C, and D of pressurizer heater operation without bleed flow, you have omitted the details of the analysis. Provide, as a minimum, the information we requested in item 5 above.

ANSWER: All four cases of this postulated event involve energy input from pressurizer heaters as the driving force to increase pressure. Each of the four cases describes different plant conditions during the postulated event. In all cases the pressure transient is a slow increase, with the rate dependent on pressure. Consequently, the analysis consisted of hand calculations utilizing, where necessary, simplifying but conservative assumptions to estimate the rate of pressure increase for each case.

III.9 QUESTION: You have also omitted the details of your analysis of the loss of shutdown cooling heat removal capacity transient. Provide, as a minimum, the information we requested in item 5 above.

ANSWER: In this postulated event, an assumed loss of heat removal ability results in energy addition to the main coolant, thus tending to increase pressure. As in the previous event (Question No. III.8), a variety of applicable plant conditions were reviewed as initial conditions, and the resulting pressure transient is a slow increase; therefore the analysis again consisted of hand calculations which conservatively estimated the rate of pressure increase for each set of initial conditions.

III.10 QUESTION: In the discussion of the loss of shutdown cooling heat removal capacity transient, you state that the expected contribution to system expansion rate is below 33 gpm, and the total expansion rate would not exceed 202 gpm.

a. Explain the differences between these rates. Is it due to an assumed letdown flow?

b. Provide a discussion of the model and assumptions used in this transient analysis which explain how the 33 and 202 gpm expansion rates were calculated.

c. At the end of the description of the transient you state that inadvertent closure of the SCS inlet isolation valves was not analyzed because of the administrative controls you use. We consider this insufficient justification, and require an analysis of this event.

ANSWER: a. The answer to this question is clearly stated in the following paragraph reproduced directly from the submittal with underlines added for emphasis:

> "The maximum expected contribution to the system expansion rate from core decay heat plus main coolant pump thermal energy is below 33 gpm, the flow rate of one charging pump. This expansion rate could be coupled with that produced by the pressurizer heaters under previously discussed conditions. The total expansion rate in any case would not exceed 202 gpm."

There is no difference in an assumed bleed (letdown) flow. The difference between the 33 gpm and the

202 gpm is due to the expected expansion rate from pressurizer heaters.

b. As stated in the answer to question No. III.9, a time dependent transient analysis of this postulated event was not performed due to the slowness of the pressure increase. The actual expansion rates due to main coolant pump heat, core decay heat and pressurizer heaters were calculated by hand, utilizing simplifying but conservative estimates.

The principal factors determining expansion rate are energy input, initial temperature, pressure and volume of the main coolant system. Variables depending on plant operating conditions are:

1. Amount of core decay heat present.

2. Number of main coolant pumps running.

3. Number of pressurizer heat groups operating.

4. Number of main coolant loops isolated (if any).

5. Bleed flow rate.

6. Pressurizer condition - solid or steam volume.

From the above, it can be seen that the number of variables affecting the system expansion rate for this postulated event are considerable. Actual conditions chosen to determine that the maximum expansion rate was below the capacity of the SCS safety valves were based upon conditions specified in normal plant operating procedures.

c. The controls and interlocks associated with the SCS isolation valves are described in answers #I.6.a., c., and d. Because of these controls and interlocks and the associated administrative controls, inadvertent closure of any SCS isolation valve is an extremely improbable event. Therefore, an analysis of a postulated overpressurization event under these conditions is considered unnecessary.

III.11 QUESTION: On page C-11 in the discussion of the MCP startup transient, you state that assuming a 100^{o}F ΔT is conservative and is "significantly greater" than the normal temperature differential. Give further justification for this assumption. Since the RCS is cooled to 220^{o}F by using the steam generators, and the RCS can be further cooled to $<100^{o}F$, why could not a larger ΔT be experienced?

ANSWER: Normal plant cooldown procedures specify that steam generator level be permitted to decrease to a low point in the narrow range band during cooldown. When main coolant temperature is about $212^{o}F$, all steam generator vent valves are opened. Subsequently, water level in the steam generators is increased to a high layup level by means of the condensate system which provides water from the main condenser at a temperature below $100^{o}F$.

We have calculated the expected final water temperature after the filling operation. The initial water inventory of the S/G was taken to be at $220^{o}F$ while the fill water was assumed to be at $100^{o}F$. The resulting average fluid temperature is less than 200 ^{o}F. The lowest practically attainable water temperature in the core area during prolonged outages is $\geq 80^{o}F$. From this, it is concluded that a $100^{o}F$ ΔT is a reasonable maximum value for an initial condition to this analysis. However, since the worst-case ΔT could reach a value of approximately $120^{o}F$, an analysis of this transient was performed using a ΔT of $150^{o}F$. The peak pressure did not exceed the Appendix G limit. Refer to Answer #III.18 for further information.

III.12 QUESTION: On page C-16, in Section A.I.1 in the formula

$$h_{CL}(i)\Big|_{t+\Delta t} = h_{CL}(i)\Big|_{t} + \frac{\Delta t * \dot{m}\ (t + \Delta t/2)}{M_{CL}(i)} * (h_{CL}\ (i-1) - h_{CL}(i))\Big|_{t}$$

Is the argument of the $\dot{m}$ term:

$t + (\Delta t/2)$ or $(t + \Delta t)/2$?

ANSWER: The argument of the $\dot{m}$ term is:

$t + (\Delta t/2)$

III.13 QUESTION: On page C-18, in Section A.II you discuss the basic assumptions of the primary system mass. One of the assumptions is:

$$M_{PRES}\Big|_{t} = M_{PRES}\Big|_{t=0} - \sum_{k=1}^{K} \dot{m}_{v}\ (k) * \Delta t$$

This states that the mass in the pressurizer can only remain constant or decrease, (e.g., no pressurizer insurge is allowed). Please discuss further the validity of this assumption after the relief valves lift. Even though the total quantity of the liquid released may be small, isn't the system peak pressure dependent on the mass and pressure in the pressurizer as well as the relief valve discharge rate?

ANSWER: The topical report describing the methodology used in analyzing the transient resulting from startup of a reactor coolant pump has been issued as YAEC-1124, "PRESS, An Analytical Model Used in PWR Overpressurization Analysis", February 1977. A detailed discussion of the manner in which the pressurizer is modeled is provided in Section 2.1 of this report. This discussion is repeated below for your review.

To facilitate the modeling of the reactor coolant pump start transient, techniques differing from those normally used in system formulations developed for two phase pressurizer situations were utilized for the RCS fluid. The primary technique utilized in PRESS which differs from conventional models is the use of constant mass nodes. Typical RCS transient models determine time dependent system performance via application of the conservative laws to fixed control volumes with varying fluid conditions and masses. In PRESS, fixed control masses with varying fluid conditions and volumes are used in applying the conservation of mass and energy principles. Although constant mass nodes with varying volumes are employed, it remains necessary, of course, to retain the total system volume constant in order that system pressure calculations be valid.

Since the solid pressurizer serves only as a mass to absorb the expansion of the loop fluid being heated, surge rates will necessarily be small since there is no steam bubble to compress. Even with the pressurizer relief valve(s) open, the small volumetric capacity of the valves and small loop expansion rates yields small surges. Thus, to facilitate modeling, the mass of each loop node was retained constant in time while the mass of the pressurizer was based on the integrated flow out the relief valve(s). To illustrate the effect of this assumption, a comparison of an actual physical situation to the representation that would result in PRESS as a result of assuming constant loop mass nodes is provided in the following discussion.

During time Δt, the energy of the primary fluid external to the pressurizer is increased by some value ΔE. The system will therefore expand into the pressurizer until a new steady-state system pressure is attained. The fluid which expanded into the pressurizer volume will be removed from the loop flow path and thus the mass in the loops will be decreased. In PRESS, the fluid which would actually expand into the pressurizer remains available for flow. Conceptually, this is accomplished by increasing the loop volume by the amount that the initial pressurizer fluid would actually be compressed. Conceptually, of course, the pressurizer volume is decreased to yield a constant total system volume. Thus, each fluid node has varying boundaries in time which depend on 1) the mass of the node, 2) the enthalpy of the node, and 3) the system pressure.

This procedure allows the system pressure to be simply calculated by the iterative solution in time of the following expression which was discussed in WYR 76-125.

$$V_{tot} = \sum_{\ell=1}^{L} M_\ell * \nu_\ell (p,h_\ell) + M_{pres}(t) * \nu_{pres}(p,h_{pres})$$

Since the system is entirely solid and therefore highly incompressible, the only significant surges occur when the pressurizer relief valve(s) open. Even for this situation, the surge rates are small, and at the time of peak RCS pressure, less than 0.1 percent of the pressurizer volume has been released through the valve. Even if significant amounts of fluid were released through the valve and consequently removed from the loop flow paths, the PRESS model would be conservative since allowing the total loop mass to be constant in time provides a larger sink for transfer of energy from the steam generator tubes to the primary, thus yielding higher RCS pressures in time.

III.14 QUESTION: On page C-18, Section A.III, in the formula describing steam generator tube temperatures in the nodes j=2 to j=J-1, is the parameter k in the second term the node's thermal conductivity, or the time index, (used in Section A.II)?

ANSWER: The parameter k is the node's thermal conductivity.

III.15 QUESTION: Section A.IV describes how the time dependent steam generator secondary water temperature is calculated. Address the following:

a. Discuss why your only source of energy to the primary fluid is the steam generator tubes and secondary fluid. Why isn't the stored energy of the steam generator internals (e.g. separators, shrouds) considered as energy sources?

b. What mass do you use for the parameter $M_{SGS}(i)$? Is it the liquid in the riser, in the downcomer, or a mixture of both?

c. In the nodal representation of the SG tubes, describe the method used for establishing the mass of each node and the value used.

ANSWER:

a. The parameters of primary importance in the secondary system with respect to determining the maximum system pressure excursion are the total secondary energy and its temperature. At the time of peak system pressure for the YR analysis the secondary nodal temperatures vary from 173 F to 190 F. Thus the main concern (i.e. maximum system pressure) occurs at a time when the secondary conditions are reduced only slightly from initial conditions with respect to heat transfer to the primary.

b. A conservative total steam generator liquid inventory consistent with cold shutdown conditions was used. As indicated in Q.III.15.a, the value chosen was sufficiently large such that the decrease in secondary fluid temperature was maximized at 27°F below its initial value at the time of peak RCS pressure. To assure that the secondary temperature decrease of 27°F does not significantly reduce the consequences of the transient an additional case was analyzed in which the secondary temperature was held constant. The result indicates a change in the peak RCS pressure of less than 5 psia.

c. The mass of each node is based on the total tube mass per steam generator and the axial and radial cross sectional nodalization of the tubes. Mathematically, this can be simply stated as follows:

$$M_n = \frac{V_n}{V_T} * M_T$$

where:

M_n = mass of a steam generator tube node

V_n = volume of a steam generator tube node

V_T = total tube volume per steam generator

M_T = total tube mass per steam generator

= 38500 lbm.

YAEC-1124 provides a detailed discussion of the above information.

III.16 QUESTION: The pressurizer relief valve discharge rate calculation is described in Section A.V. The quantity FRAC sets the fractional flow rate, given the theoretical full open flow at pressure P. Three fractions are shown, one being time dependent. Explain the use of the time dependent term for determining your relief valve discharge rate. How do you determine the quantity DT? Is the time it takes to reach full open dependent on the system pressure?

ANSWER: The time dependent term was used only as a sensitivity study parameter. For the analysis performed in which the valve opening was a function of tire the pressure argument remained valid. Thus the fraction of valve opening was determined as follows:

FRAC = Minimum of (1.0, (P-500)/50, $(t-t_s)/10$)

where: FRAC is the fraction of full valve opening

P is the system pressure

t is time

t_s is time at which the valve opening pressure of 500 psia is attained.

III.17 QUESTION: The determination of the pressurizer relief valve discharge rate is discussed in Section A.VIII. We will require further information as listed below.

a. What K_D are you using?

b. Appendix XI to ASME Section VIII gives capacity conversions for safety valves. Do your relief valves qualify for using Figure UA-231 to determine liquid flow rate? How does the value from this figure compare with your computed values? Discuss any differences.

c. You state that assuming a saturated condition in the pressurizer yields a conservative relief valve flow rate. Please justify this statement by providing a table of flow rates with corresponding critical pressures, for a number of subcooled and saturated inlet conditions.

d. Describe how you go from the critical flow rate calculated in the formula, to the flow rate vs. system pressure shown in Figure A-1. What backpressure is assumed?

e. Please note that the units for terms g_c and J are incorrect.

ANSWER:

a) A discharge coefficient of .271 was used in the analysis. This value was conservatively determined by reducing the K_D for steam discharge of 0.301 by 10%.

b) The values provided in Appendix XI to ASME Section VIII are based on the same methodology used in our analysis (i.e., Isentropic Homogeneous Expansion Model). Thus the results will be the same for identical conditions. The presently installed relief valve at Yankee Rowe is an old design as evidenced above by its discharge coefficient of 0.301 (0.271 used). Thus the capacity at 400 psia saturated fluid conditions is considerably less than that provided in Figure UA-231 which is applicable for relief valves with a discharge coefficient in excess of 0.90. The calculated capacity of the presently installed valve for saturated liquid at 400 psia is 1.87×10^4 lbm/hr-in^2. This is less than 32% of the value provided in Figure UA-231.

The proposed replacement valve for Yankee Rowe has a discharge coefficient of 0.95 which yields a capacity of 5.94×10^4 lbm/hr-in^2 for saturated liquid at 400 psia. This is consistent with Figure UA-231.

c) Figures III.17.1 and III.17.2 provide the critical pressure ratios and discharge capa ities for a numbe. of situations. Also included is a specification of the values used in our analyses which shows the conservative approach taken.

d) To obtain the flow rates provided in Figure A-1 from the Isentropic Homogeneous Expansion formulation provided on page C-20 (i.e. $\dot{m} = 0.9 * K_D * \dot{m}_c$). The following procedure is used:

$$Q \text{ (GPM)} = \dot{m} \text{ (lbm/sec)} * \frac{60 \text{ sec}}{(\text{min})} * v(P_o, h_o) * (7.481 \text{ gal/ft}^3)$$

where Q = volumetric flow rate

$\dot{m}$ = mass flow rate

v = specific volume

P_o = stagnation pressure

h_o = stagnation enthalpy

Inherent in the model is that the system backpressure be less than the critical pressure. Thus, to assure that the model is applicable for the pressurizer relief valve it is necessary to determine the critical pressure and compare this to the backpressure that could exist. Figure III.17.1 provides the critical pressure ratio versus stagnation temperature for a number of stagnation pressures. Since the pressurizer relief valves open at 500 psia in the analysis, the 500 psia trace is of interest. Since the discharge fluid stagnation temperature was conservatively assumed to be 445°F, it is evident that a very high critical pressure ratio exists (.797). This critical pressure ratio yields a critical pressure of 398 psia. This value is significantly greater than any backpressure that could exist and thus validates the assumption of critical flow conditions in the valve.

e) Noted, but does not affect results.

III.18 QUESTION: The results of your analysis of the RCP flow initiation transient are discussed in Section B, on page C-24. We have reviewed these results and request the following additional information:

a) Please discuss the sensitivity of your analyses to the following:

1. Number of nodes in the model,

2. Initial RCS pressure and temperature,

3. Initial pressurizer temperature,

4. Initial steam generator temperature.

b) Perform an analysis of the RCS pressure response assuming:

1. Both SCS code safety valves and no pressurizer relief valves open.

2. No reliefs or safety valves open (for sensitivity study pu., oses).

ANSWER: a)

1. YAEC-1124 provides a parametric study of the sensitivity of the transient to the number of nodes in the analysis. The study shows that the number of nodes in the YR submittal is adequate.

2. The prime concern with the initial temperatures is the secondary to primary differential. To illustrate the minor effect of varying the initial RCS pressure and temperature while retaining the 100^{o}F secondary to primary temperature differential the following cases were analyzed.

   1) T_{RCS} = 150^{o}F, P_{RCS} = 400 psia

   2) T_{RCS} = 50^{o}F, P_{RCS} = 400 psia

   3) T_{RCS} = 200^{o}F, P_{RCS} = 400 psia

   4) T_{RCS} = 150^{o}F, P_{RCS} = 100 psia

   5) T_{RCS} = 50^{o}F, P_{RCS} = 100 psia

   6) T_{RCS} = 200^{o}F, P_{RCS} = 100 psia

   7) T_{RCS} = 100^{o}F, P_{RCS} = 100 psia

   where T_{RCS} = initial RCS temperature

   P_{RCS} = Initial RCS pressure

   Results are tabulated in Table III.18. In addition, an analysis was performed with a secondary to primary temperature differential of 150^{o}F (T_{sec} = 250^{o}F, T_{RCS} = 100^{o}F, P_{RCS} = 400 initially). Although this event cannot occur, results show that the consequences remain acceptable as shown in Table III.18.

3. The results of the transient are dependent on the initial pressurizer temperature only with respect to the pressurizer relief valve discharge capacities. Thus, the conservative values used in our analysis bound less conservative (yet more realistic) initial pressurizer conditions.

4. The initial steam generator temperature is only important with respect to the differential temperature that it imposes with respect to the RCS. This has been discussed in part 2)

above.

b)

1. Figure III.18.1 provides the results of this analysis for the following case.

   Initial RCS temperature = 100°F
   Initial secondary temperature=200°F
   Initial RCS pressure = 300 psia
   50 second linear flow acceleration for primary fluid

   The peak RCS pressures are less than those calculated with the pressurizer relief valves available due to the increased SCS valve capacity, and thus the results are acceptable.

2. Figure III.18.2 provides this analysis for the following initial conditions:

   1) T_{RCS} = 100°F
   2) T_{sec} = 200°F
   3) P_{RCS} = 400 psia

III.19 QUESTION: Note 2 on page C-27 says that the time dependent fraction used in Section A.V is intended to adjust the throat area available for flow. Is this fraction allowed to exceed 1.0?

ANSWER: The response to question III.19 was provided in the previous response to Question III.16. The program was written to allow either pressure or time to control the opening characteristics of the valve. The expression provided in the response to Question III.16 is included in this exact form in the program.

Table III.18

Reactor Coolant System Pressure Versus Initial Temperature and Pressure

T_{RCS}(F)	T_{SEC}(F)	P_{RCS}(psia)	Peak System Pressure (psia)
100	200	400	520 (base case)
100	200	100	520
50	150	400	513
50	150	100	513
150	250	400	531
150	250	100	531
200	300	400	538
200	300	100	538
100	250	400	536

a. 100% IHE Flow

50 sec. ..near flow acceleration

10% valve accumulation (P_{open} = 500 psia, P_{full} = 550 psia)

Note: For the analyses performed from an initial condition of 100 psia, the relief valve capacity was based on relieving 445°F water as was assumed in the cases initiated from 400 psia. This is clearly conservative since the saturation temperature of 100 psia is 328 °F and the capacity of the valves increased with decreasing temperature.

IV.1 QUESTION: Your submittal includes analyses of different RCS pressure transient causing events with a variety of mitigating measures. As indicated above, we will require an analysis of each event, based on the mitigating equipment you intend to install. Your response should clearly define the mitigating equipment assumed to be installed, the method of analysis, the single failures considered, and the operator action criterion assumed for:

a. Inadvertent ECCS operation,

b. Charging without bleed flow,

c. Pressurizer heater operation without bleed flow,

d. Loss of shutdown cooling heat removal capacity.

ANSWER: The answer to this question has been provided in the response to several of the previous questions which have dealt individually with each of the above mentioned events.

IV.2 QUESTION: You have indicated that a higher capacity solenoid operated pressurizer relief valve will be installed by June 30, 1978. We require the following information with respect to this new pressure mitigating system.

a. Your anticipated pressure-temperature limit curves (and Appendix G limits) as they will exist in June 1978.

b. Your present pressure-temperature curves expire at the end of core cycle XII, (about mid-summer 1977). If analyses show a more restrictive Appendix G limit as a result of vessel irradiation, what overpressure protective measures will you implement until the high-capacity valve is installed in June 1978?

c. Provide justification that the proposed dual setpoint, high capacity pressurizer relief valve will provide sufficient relief capacity with adequate response time during those transients analyzed in your December 1976 submittal.

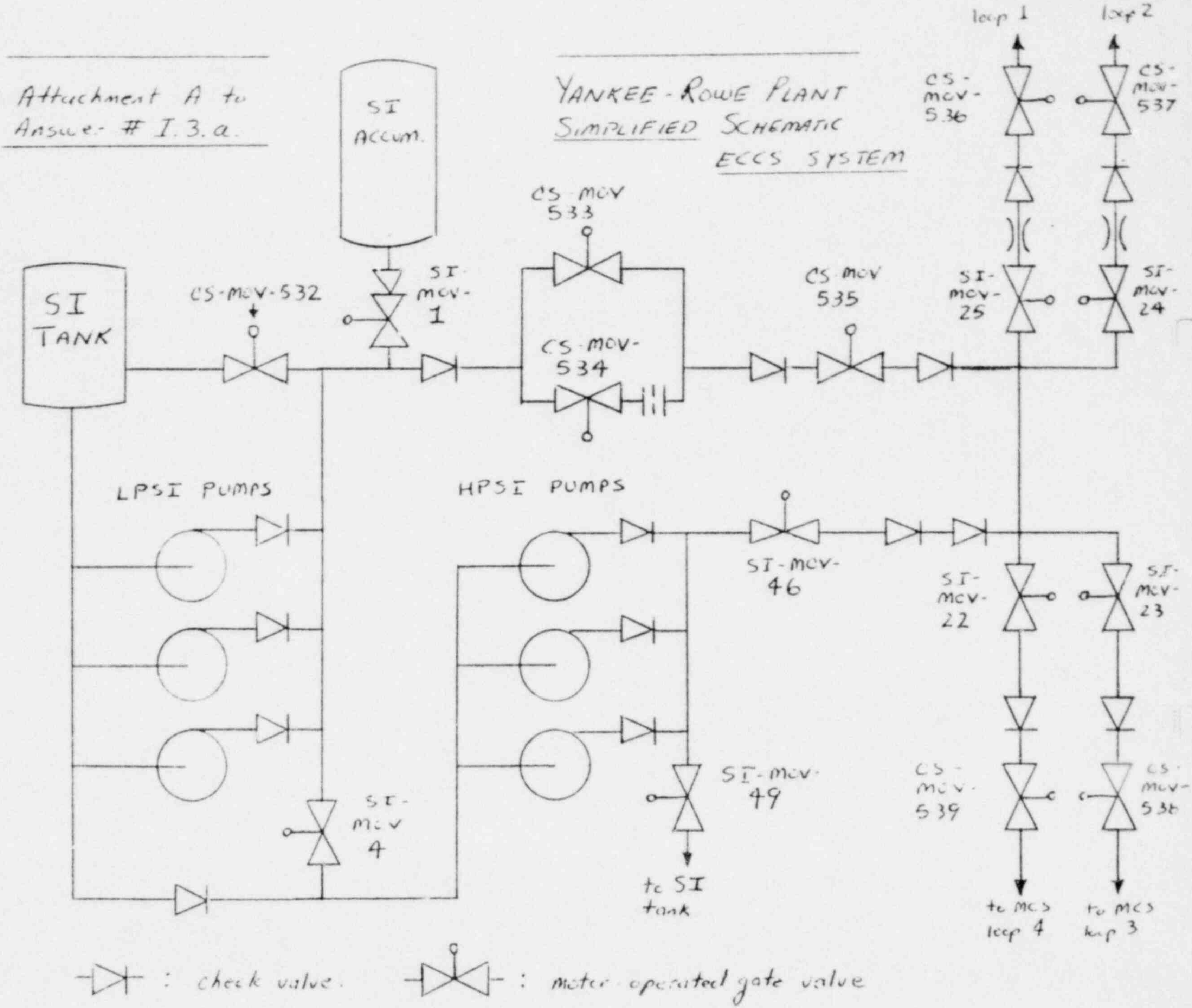
ANSWER: Technical Specifications Figures 3.4-4 and 3.4-5 define the pressure-temperature limits applicable to reactor vessel overpressurization. The presently applicable limit curves have served as the basis for the initial submittal on overpressurization. The bases for these curves state that they will be revised each refueling outage without a change submittal to the Technical Specifications. The revised limit curves have not been generated yet and cannot be provided. However, for the purposes of ascertaining the impact of the impending limit curve changes on overpressurization, the future curves have been estimated following the procedure outlined in the bases to the Technical Specifications (i.e. utilizing Figures B3/4.4-1 and B3/4.4-2). The expected shift in RT_{NDT} at the 1/4t and 3/4t locations is on the order of a few degrees F. This will have a minimal impact on the protection afforded for reactor vessel overpressurization. It is expected that no protection or degree of redundancy discussed in either the original submittal or the response to these questions will be invalidated by this shift. As stated in the answer to question III.1.c, a review of the adequacy of protection against overpressurization incidents is to be performed each refueling outage in light of the shift in the Appendix G limit curves. If the review indicates the need for further changes in either procedures or equipment, such action will be taken.

The June 30, 1978 date dated in our original submittal and quoted above was the anticipated date for the Core XIV refueling outage. We wish to note that the replacement pressurizer relief valve is scheduled to be installed during the Core XIV refueling outage as opposed to June 30, 1978.

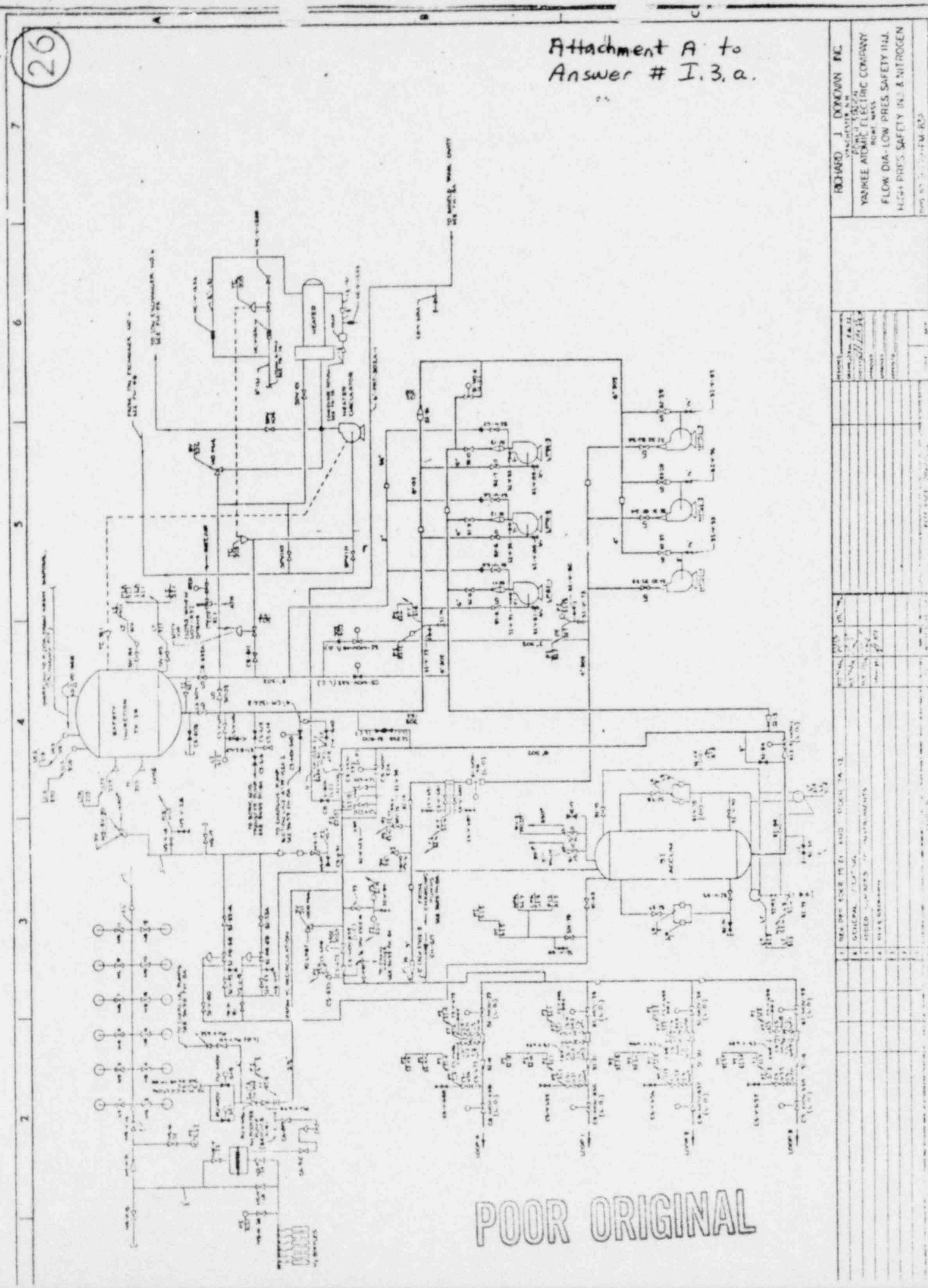
We do not understand Question IV.2.c. Is the conservatively calculated capacity of the pressurizer relief valve shown in Figure A-1 of Appendix C to the original submittal inadequate? We request a further explanation of this question before proceeding with an answer.

Attachment A to Answer # I.3.a.

YANKEE-ROWE PLANT SIMPLIFIED SCHEMATIC ECCS SYSTEM



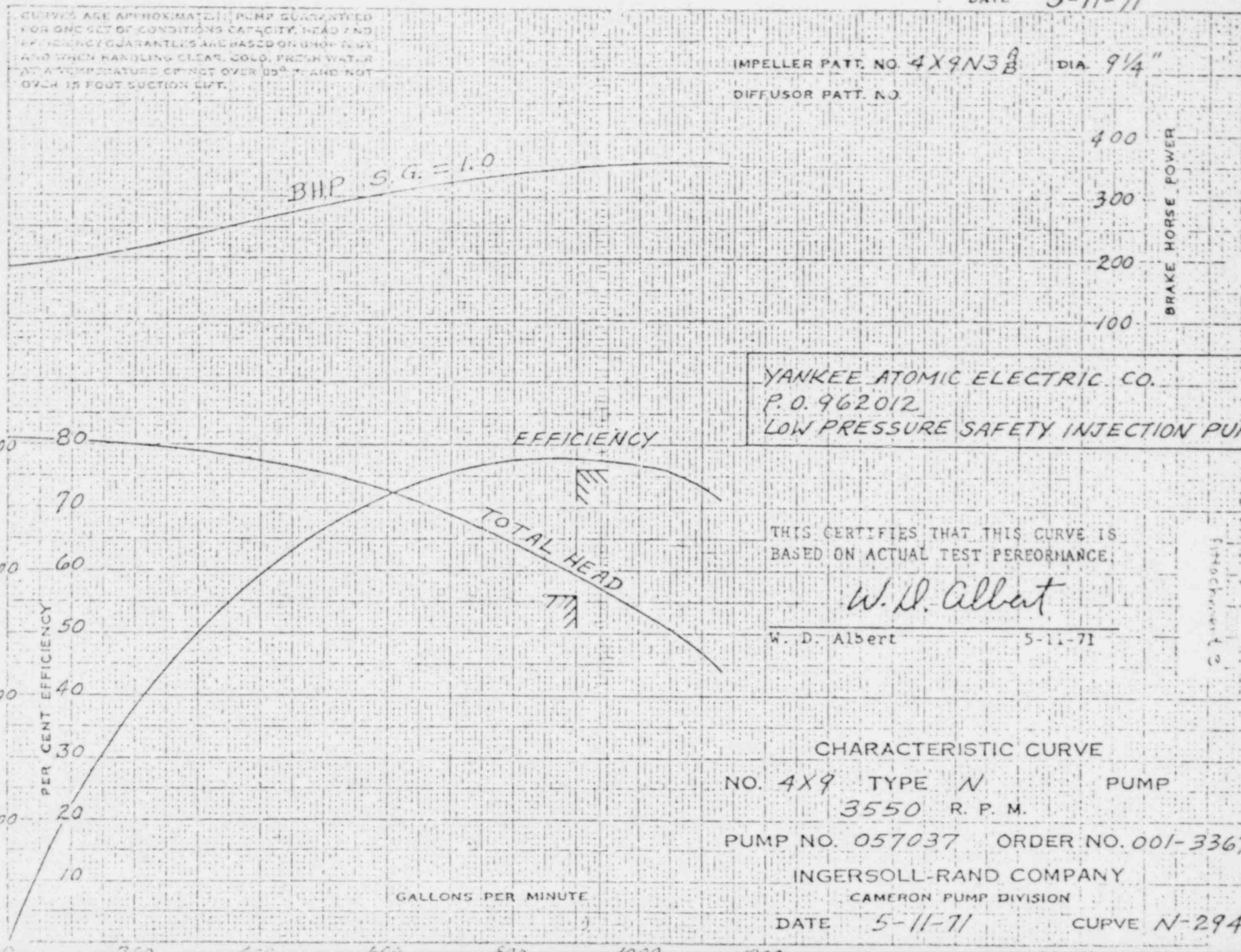
Attachment A to Answer # I.3.a.



POOR ORIGINAL

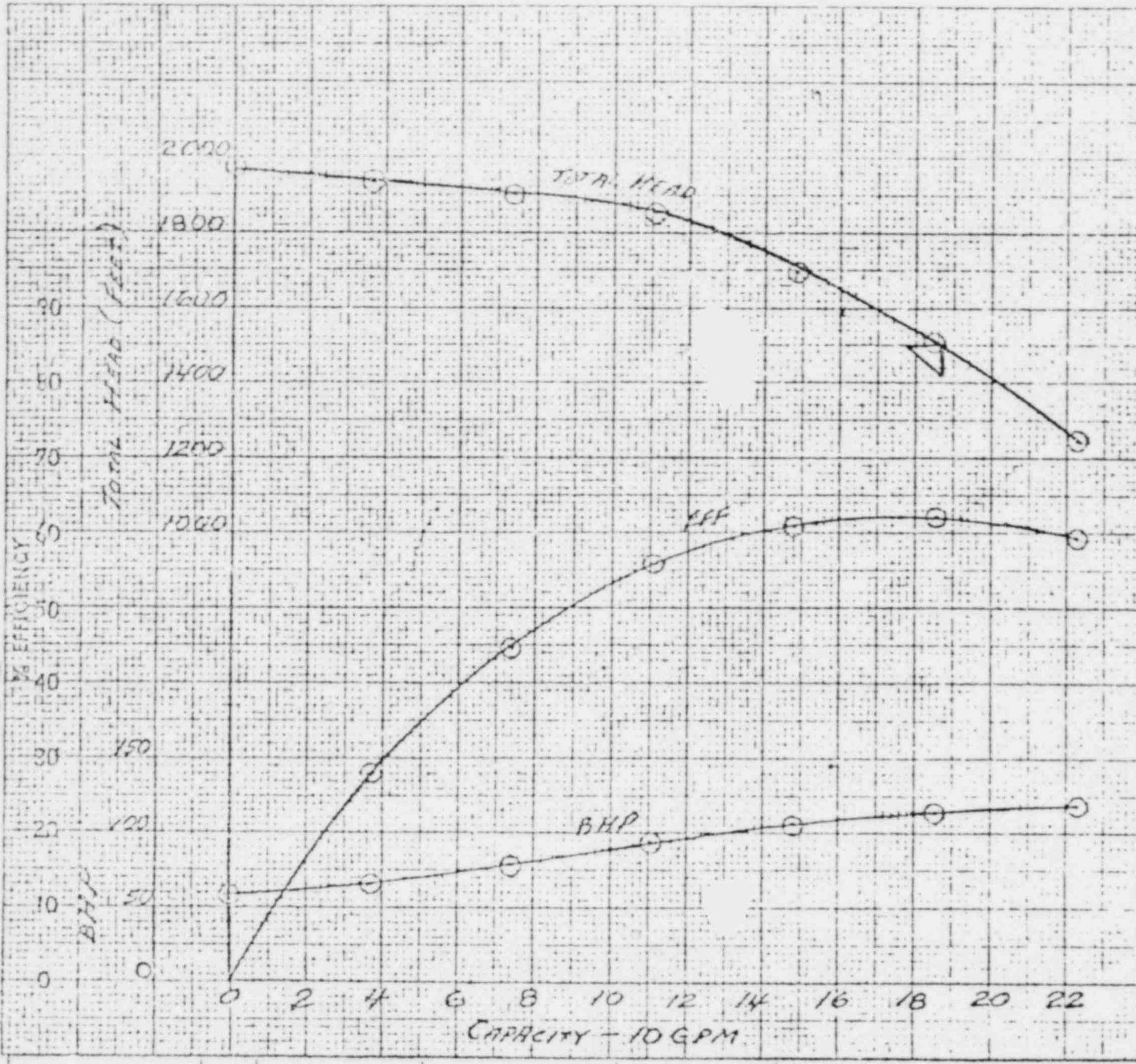
Attachment B to Answer # I.3.a.

CURVE NO. N-294
DATE 5-11-71



Attachment C

Attachment C to Answer I.3.a:



WORTHINGTON CORPORATION
PUMP TEST DATA

RPM	GPM	HD.	BHP	EFF.
2990	0	1394	34.1	0
2990	31.2	1373	38.9	27.9
2988	62.5	1347	47.6	44.7
2986	93.7	1310	55.7	55.7
2985	124.9	1200	62.5	60.1
2983	156.1	1061	67.3	62.1
2974	187.3	877	70.0	59.3

YANKEE ATOMIC ELECTRIC CO.
HPSI PUMP

CASING DATA

MATERIAL	FINISH	TONGUE
316 SS		

IMPELLER DATA

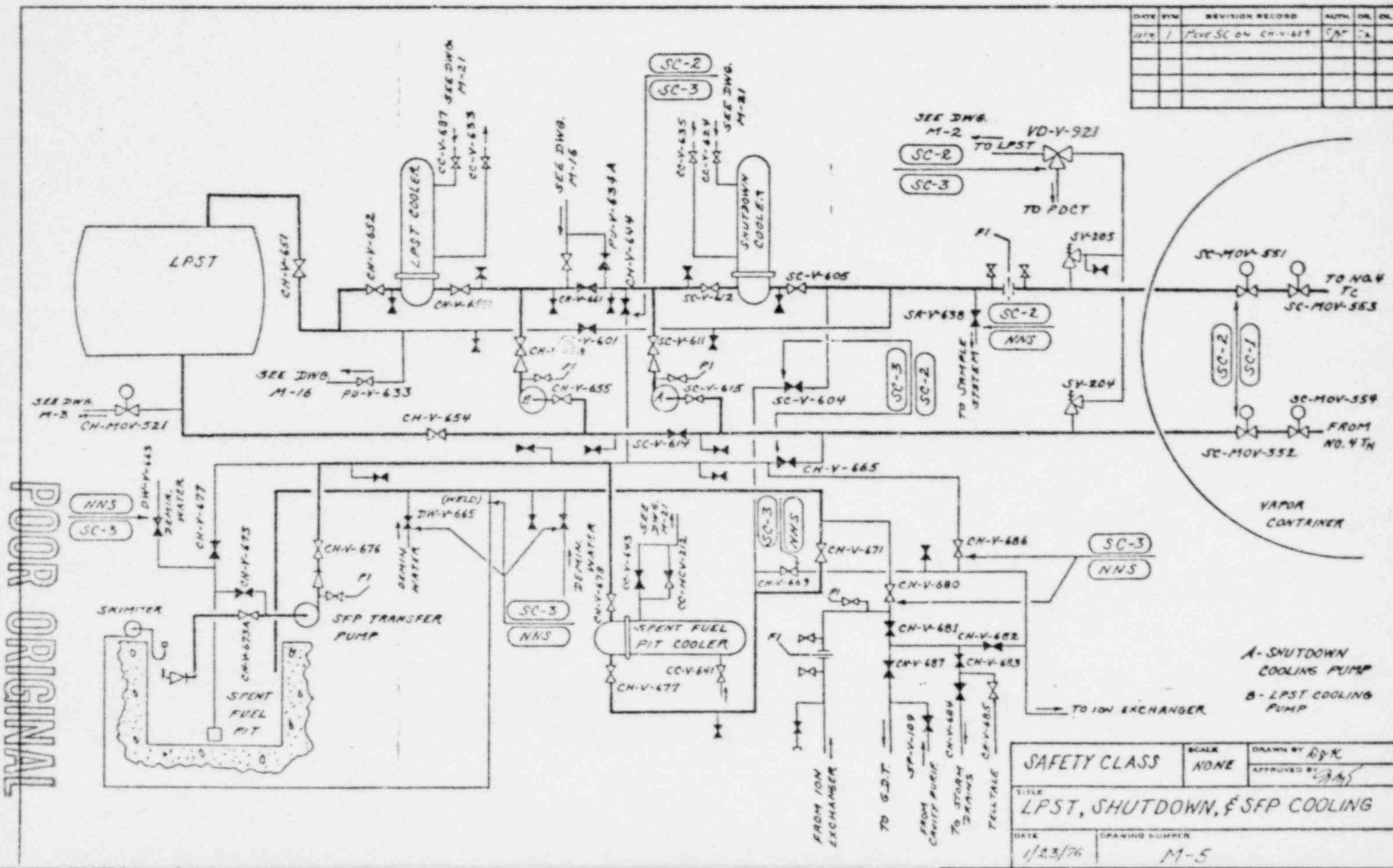
MATERIAL	FINISH	DISC. TIPS
316SS	1	

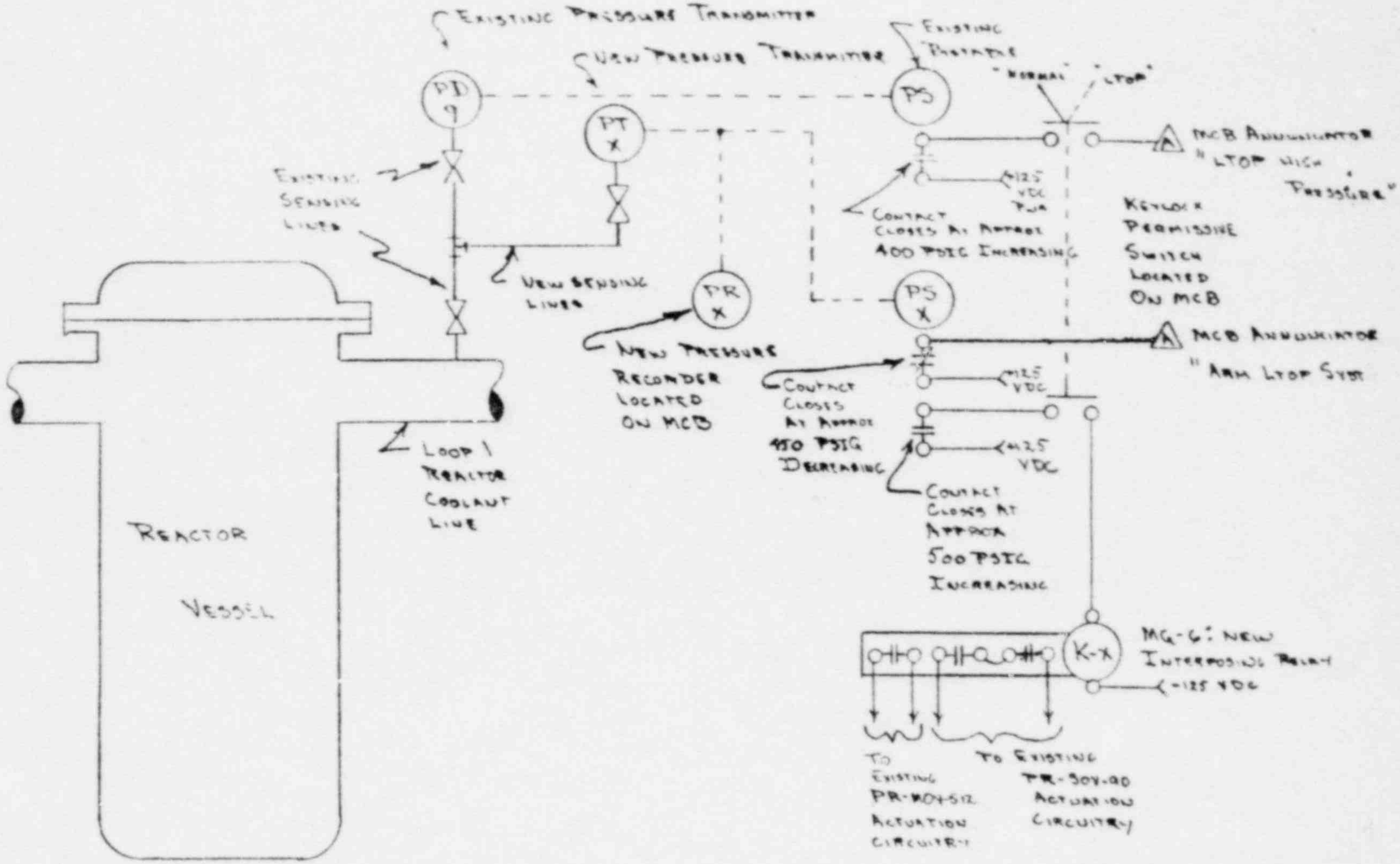
PATT. NO.	COMB. NO.	DIA.
UB4801A	A-1	$8\frac{1}{8}$

PUMP	STAGES	ORDER NO.	SERIAL NO.	DATE TEST	TEST	APPROVED	TEST DRIVER	VENTURI	PLOTTED RPM	CURVE NO.
2WTF87	7	Z000018	70-Z000018-3	7/1/71					3550	E196615

POOR ORIGINAL

Attachment D to Answer # I.6.a.





YANKEE ROWE LOW TEMPERATURE OVERPRESSURIZATION (LTOP) TRANSIENT PROTECTION SYSTEM

TMJH. 5/17/77

SKETCH #1

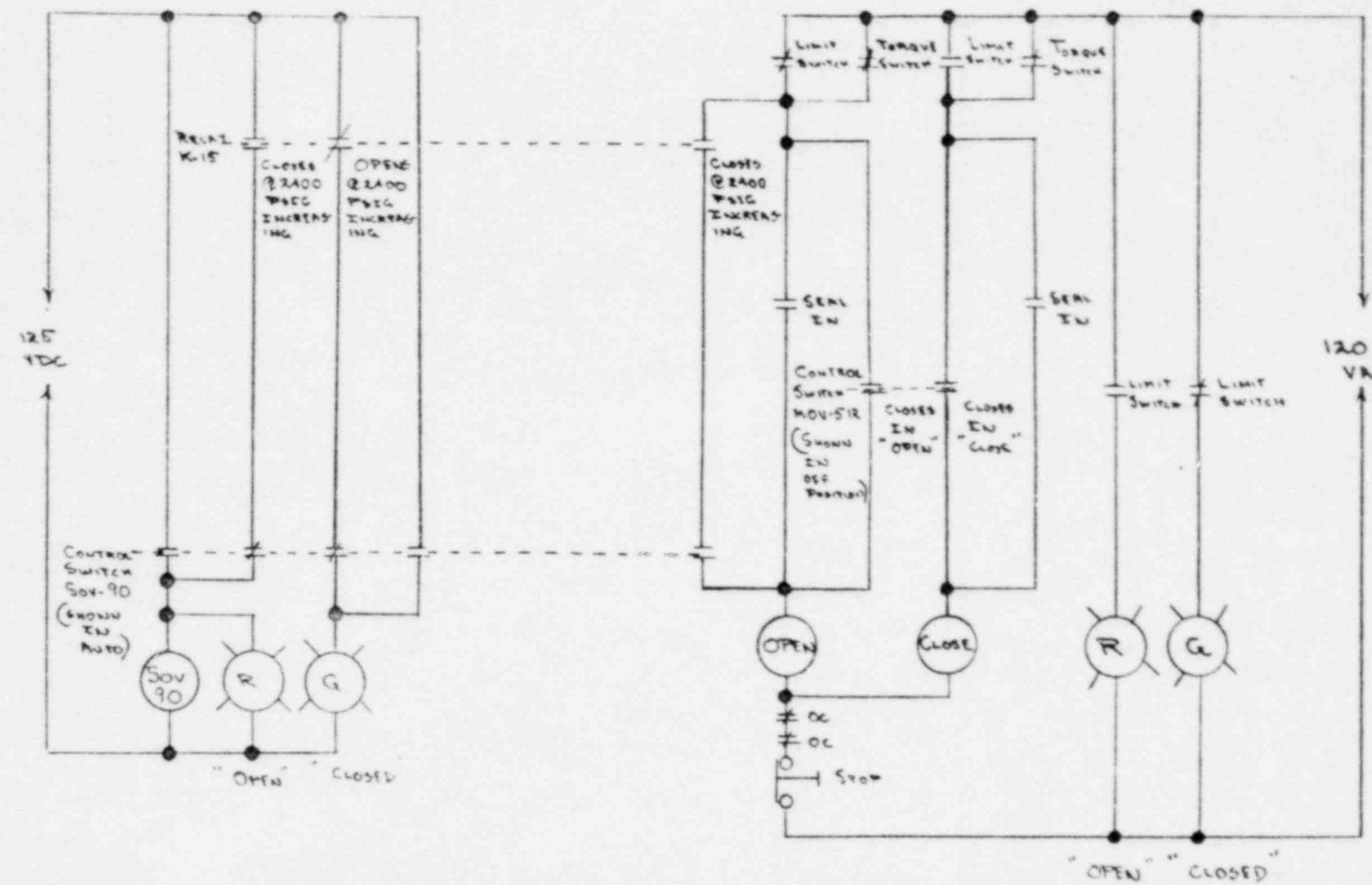
(Question + Answer # II.3)

PRESSURE RELIEF VALVE PR-SOV-90
ACTUATION CIRCUITRY

SHOWN WITH SWITCH IN "AUTO", VALVE CLOSED

PRESSURE RELIEF ISOLATION VALVE - PR-MOV-512
ACTUATION CIRCUITRY

SHOWN WITH SWITCH IN "OFF", VALVE CLOSED



EXISTING
CIRCUITRY
SKETCH #2

(Question & Answer
II.3)

DJ 5/17/77

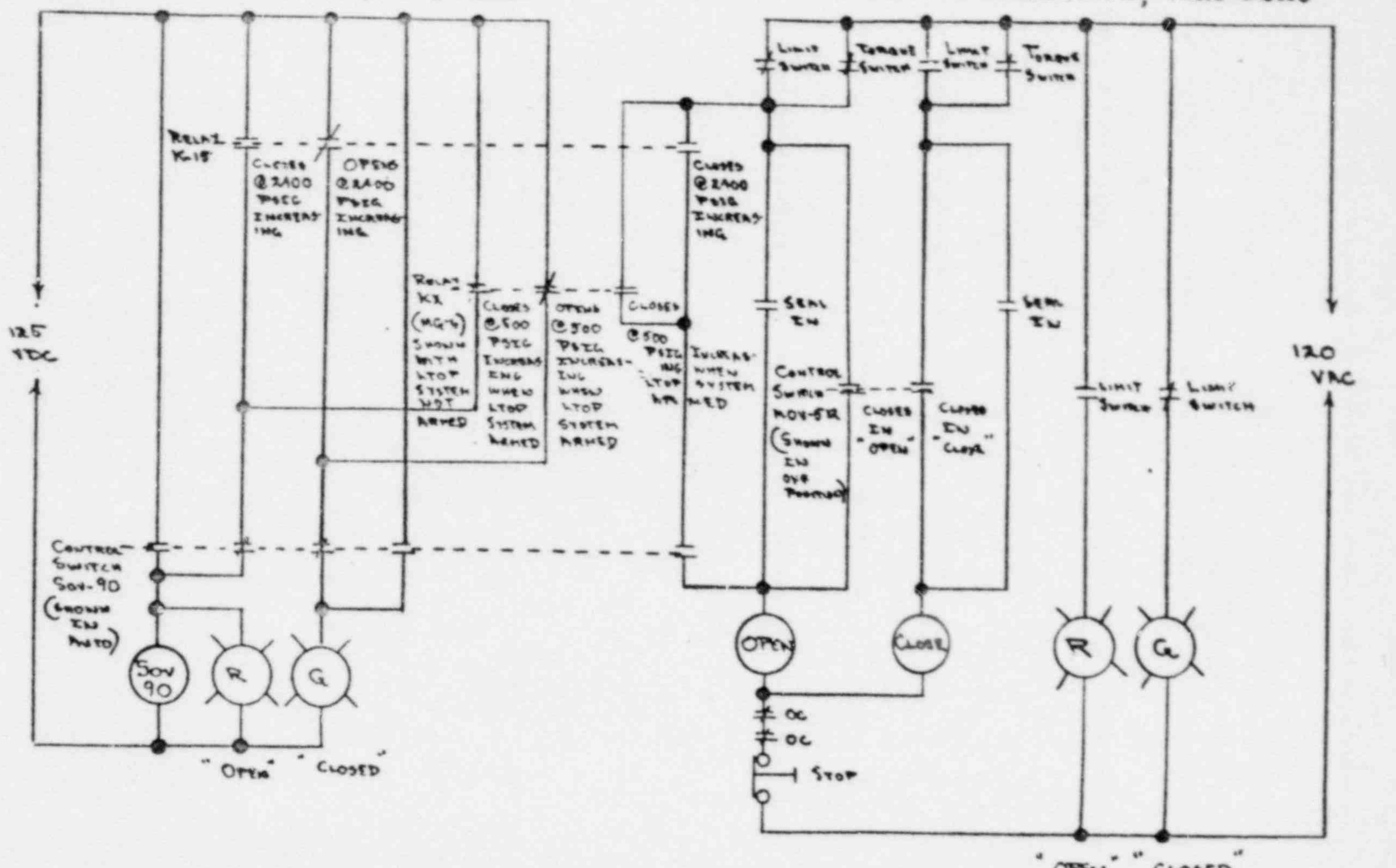
POOR ORIGINAL

PRESSURE RELIEF VALVE PR-SOV-90
ACTUATION CIRCUITRY

SHOWN WITH SWITCH IN "AUTO", VALVE CLOSED

PRESSURE RELIEF ISOLATION VALVE - PR-MOV-512
ACTUATION CIRCUITRY

SHOWN WITH SWITCH IN "OFF", VALVE CLOSED



NEW CIRCUITRY

SKETCH # 3

(Question + Answer # II.3)

DWJ 5/17/77

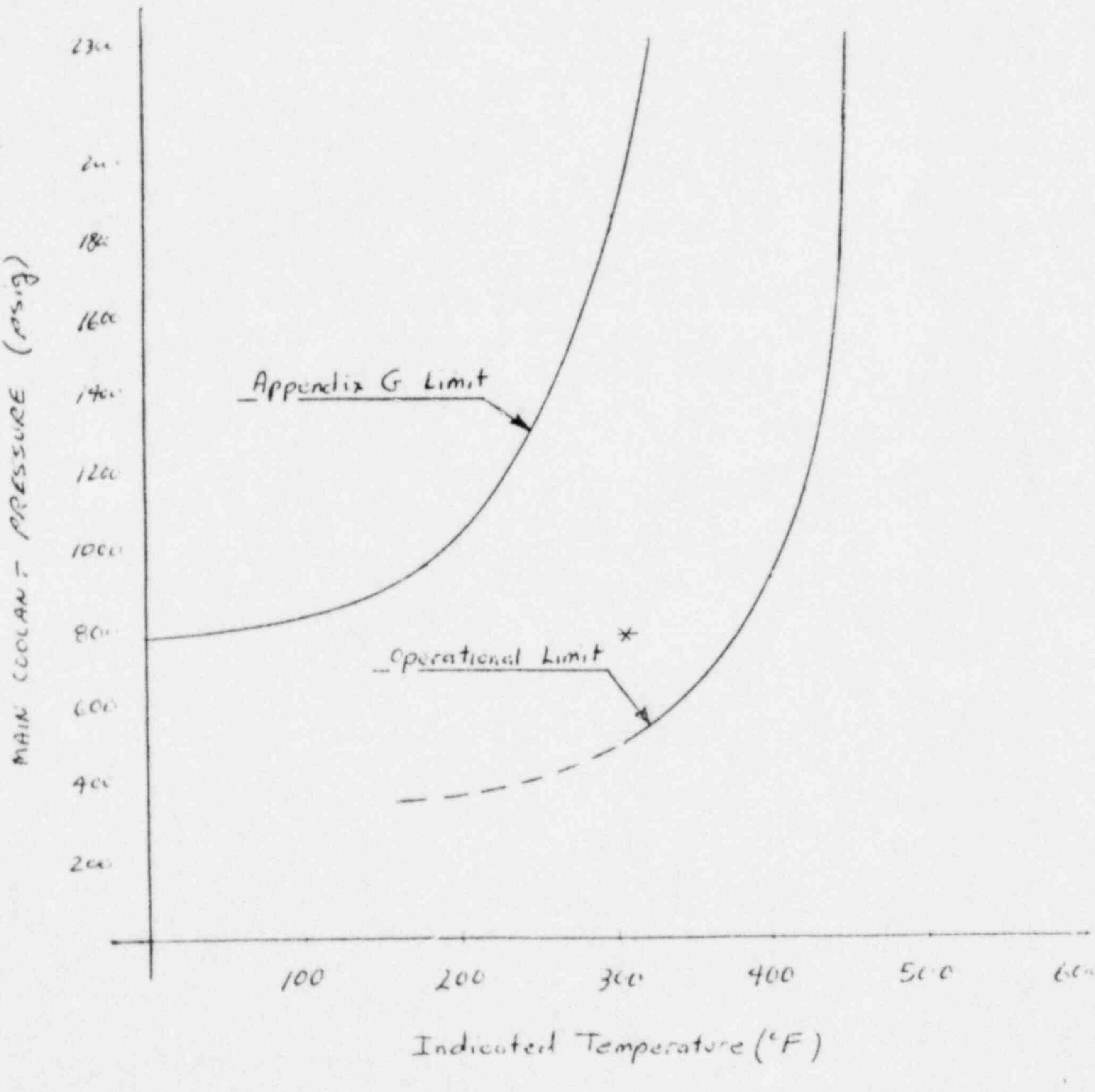


Figure III.2

POOR ORIGINAL

* Refer to Answer # III.6

Simplified hematic Diagram
of a Single Train of ECCS

Reactor Vessel Overpressurization
Safety and Relief Valves also shown.

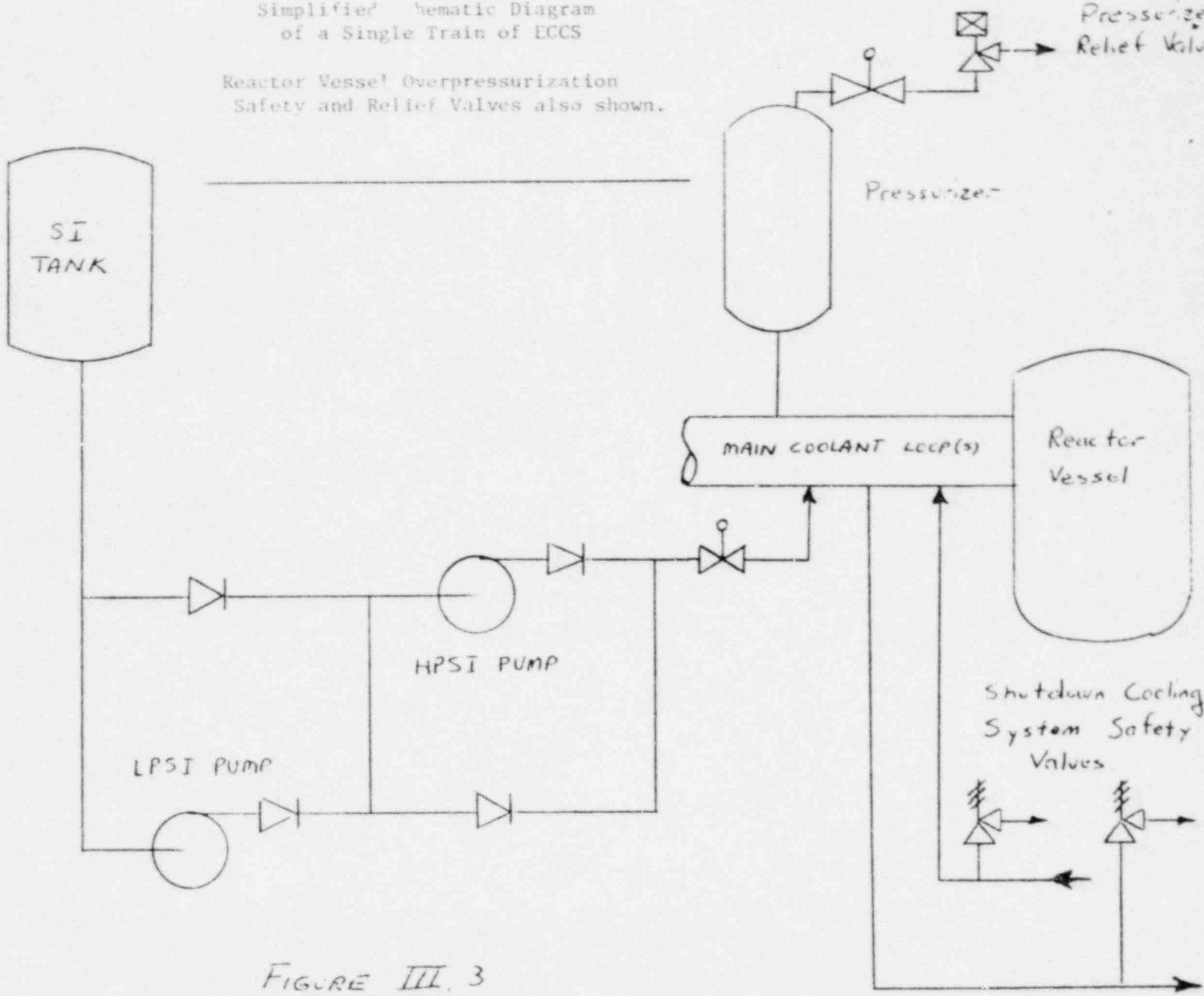
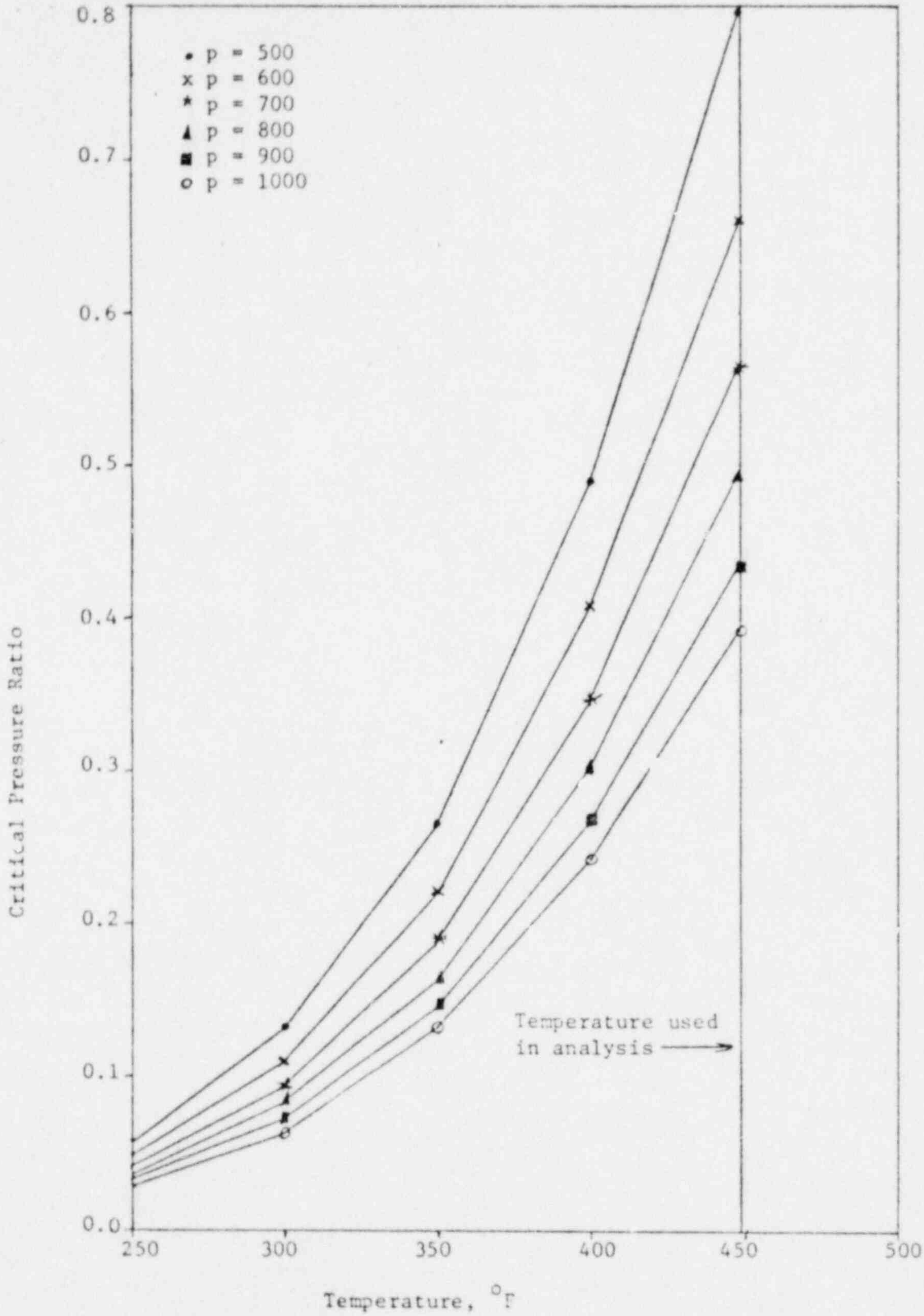


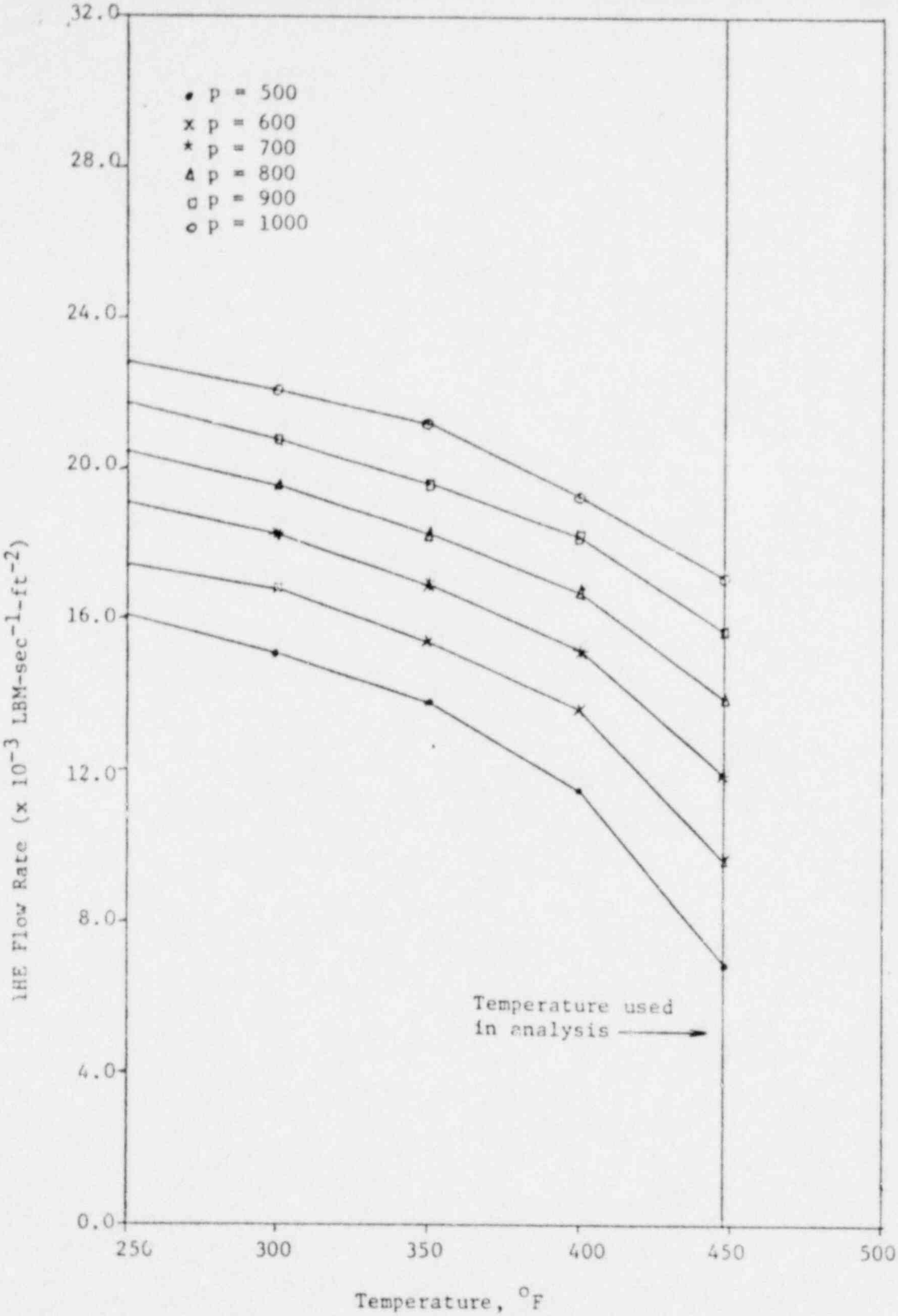
FIGURE III. 3



YANKEE ATOMIC ELECTRIC COMPANY
20 TURNPIKE ROAD WESTBORO MASS
NUCLEAR SERVICES DIVISION

DWG NO. III.17.1

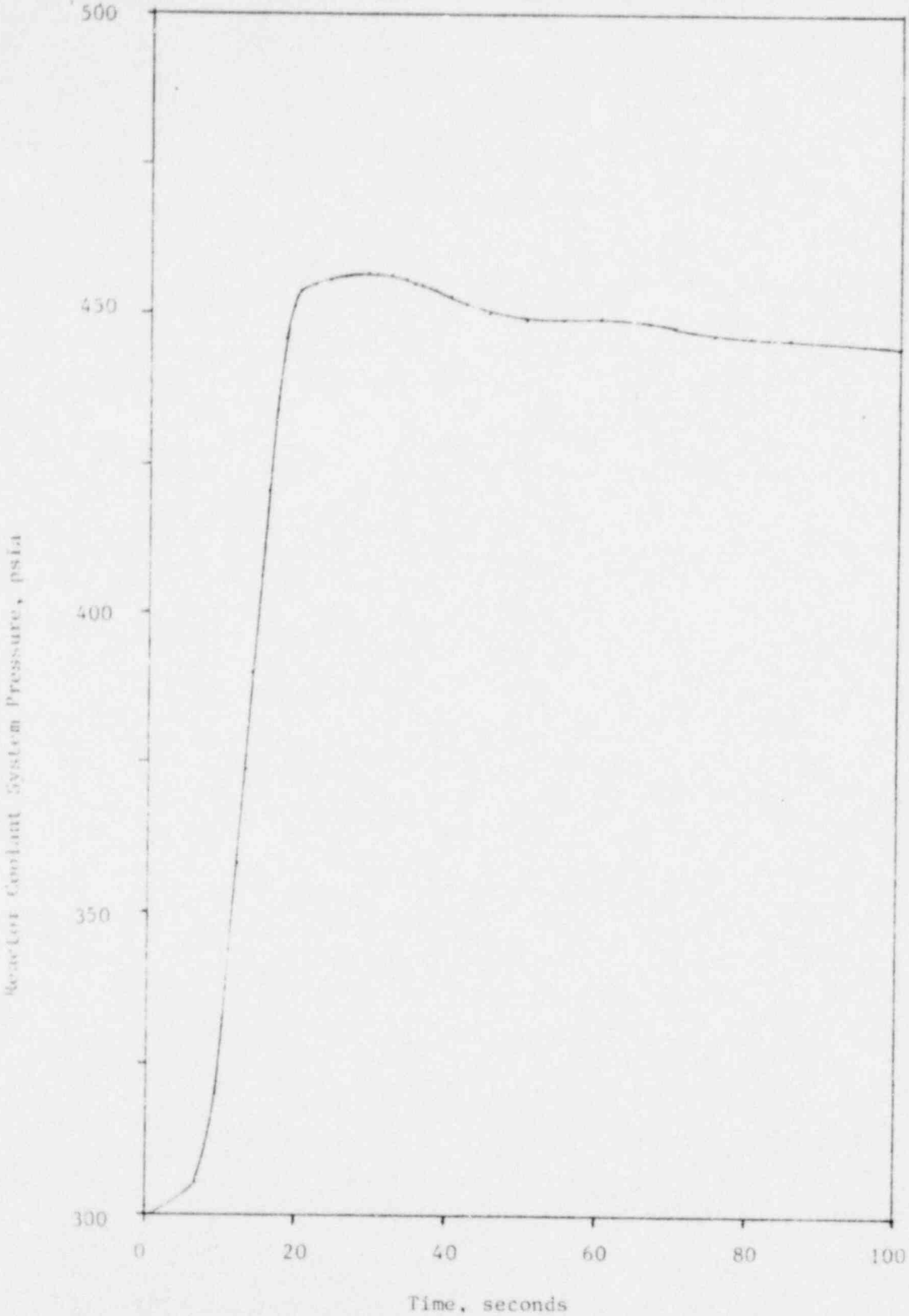
TITLE
Critical Pressure Ratio versus Temperature and Pressure



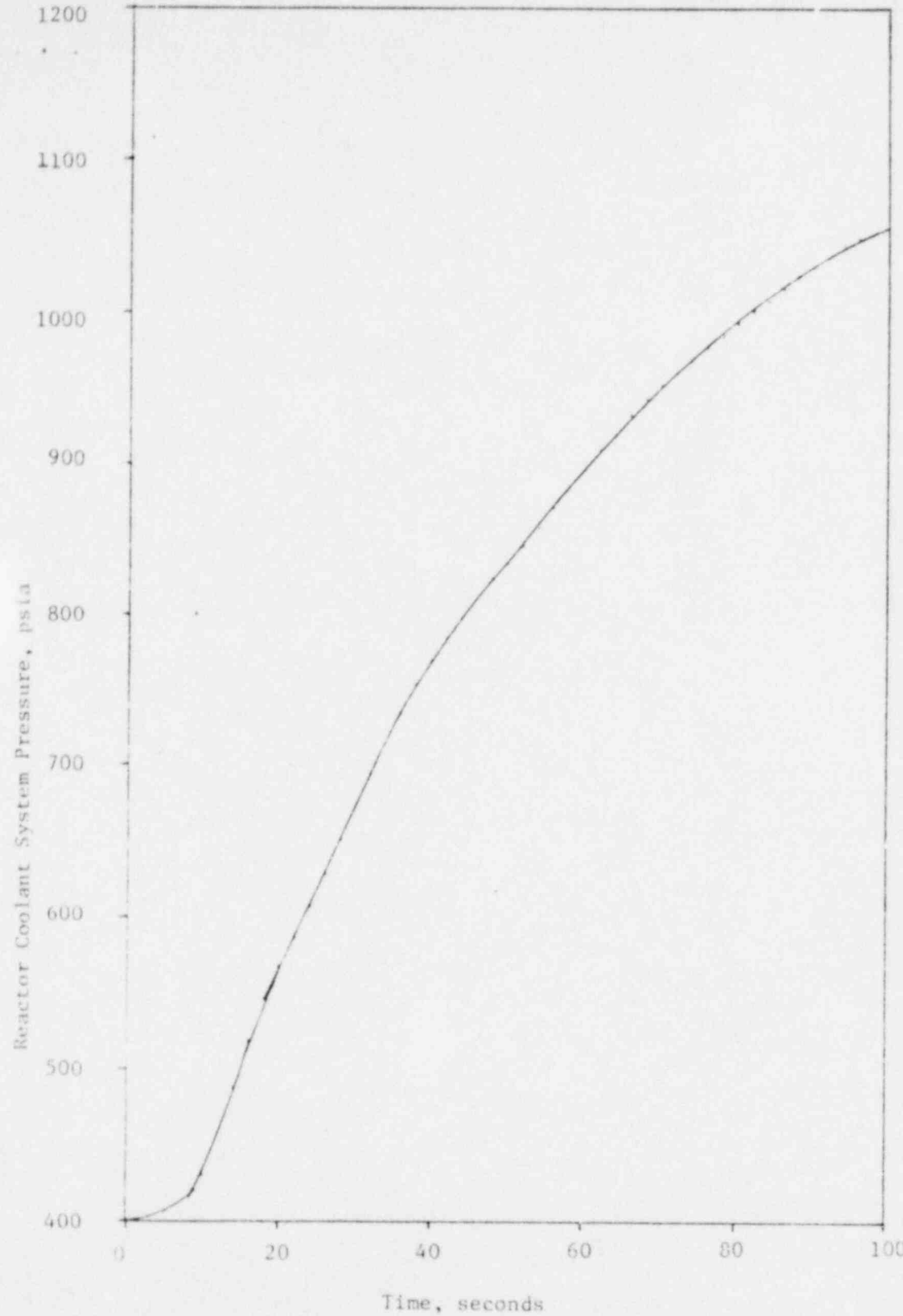
YANKEE ATOMIC ELECTRIC COMPANY
20 TURNPIKE ROAD WESTBORO MASS
NUCLEAR SERVICES DIVISION

DWG NO. III.17.2

TITLE.
IHE Flow Rate
versus
Temperature+Pressure



YANKEE ATOMIC ELECTRIC COMPANY 20 TURNPIKE ROAD WESTBORO MASS. NUCLEAR SERVICES DIVISION	DRAWN BY	TITLE RCS Pressure versus Time With SCS Safety Valves Available
	CHECKED BY	
DWG NO. III.13.1	APPROVED BY	



YANKEE ATOMIC ELECTRIC COMPANY 20 TURNPIKE ROAD WESTBORO MASS. NUCLEAR SERVICES DIVISION	DRAWN BY CHECKED BY	TITLE RCS Pressure versus Time Without Safety or Relief Valves
DWG. NO. 111.18.2	APPROVED BY	

U.S. NUCLEAR REGULATORY COMMISSION

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Response to NRC questions regarding the Yankee Rowe sub,ittal on Reactor Vessel Overpressurization...........

(1/4")

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POOR ORIGINAL

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