Modeling A Boiler Feed Pump Drive Turbine With Extractions (Sometimes it is a little trickly)

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ABSTRACT

Sometimes PEPSE models of boiler feed pump drive turbines (BFPDT) can be computationally unstable, and this can be frustrating. This paper presents a method to resolve instability and therefore removes this cause of frustration.

The method is based on the results of investigation of the behavior and discovery of the cause of the instability. The problems often occur for a BFPDT that includes multiple extractions from the turbine and includes exhaust to the feedwater heater train. The cause of the trouble is the competition for steam among the extractions and the exhaust. This is compounded by the fact that the power required by the pump must be produced by the turbine string.

The method of resolution is to assure adequate feedwater heater shell steam supply in the computation. In addition the method of satisfying the competing steam demands ensures that the exhaust feedwater heater does not experience reset of the drain condition.

1.0 Introduction

Commonwealth Edison (CeCo) is a large midwest utility with 23,645 MW of generating capacity. Its service territory is approximately the northern fifth of Illinois including Chicago. The generating mix consists of 12 nuclear units (12,045 MW), 24 fossil units (10,268 MW), and peaking units (1,332 MW). CeCo serves over three million customers in their territory.

CeCo's Will County Unit 4 (WC4) is a 542 MW coal fired unit located in Romeoville, Illinois. Due to economics, the nuclear units are baseloaded. The fossil units do all of the cycling, therefore all the coal fired units need to operate in a flexible mode. WC4 is no exception. WC4 has an all coal minimum load of 160 MW and a minimum load of 50 MW with support fuel (#2 oil). Because of the flexibility of the unit, the PEPSE model must also be very flexible. PEPSE analysis must be performed for many operating conditions such as variable pressure, low load, FWH out of service, etc. This type of flexibility was difficult to build into the WC4 model due to the unit's unique boiler feed pump drive turbine (BFPDT) extractions to feedwater heaters.

WC4 is a cross compound General Electric turbine with inlet steam conditions of 2400/1000. The unit is distinctive in several ways (see Fig.1, the vendor heat balance). The most intriguing to the PEPSE model is the configuration of the BFPDT. The turbine has three sections and two extractions, with the exhaust going to "D" feedwater heater, which is the top low pressure heater. The first and second extractions of the BFPDT go to the "F" and "E" heaters respectively, with the "F" heater being the first high pressure heater, and the "E" heater being the deaerator. The difficulties encountered with the modeling of the boiler feed pump turbine extractions, and the solution to these difficulties are the subject of this paper.

2.0 Will County Unit 4 PEPSE Model Problems and History

The difficulty in modeling WC4 is caused by the competing demands of the steam to the BFPDT (see Figure 2). As in any BFPDT, the steam supplied must meet the power requirements of the boiler feed pump. When a BFPDT extracts (and exhausts) to feedwater heaters, this creates additional demands. Since WC4's "D" heater's only source of extraction steam is the exhaust of the BFPDT, the flow through the third and final section of the BFPDT

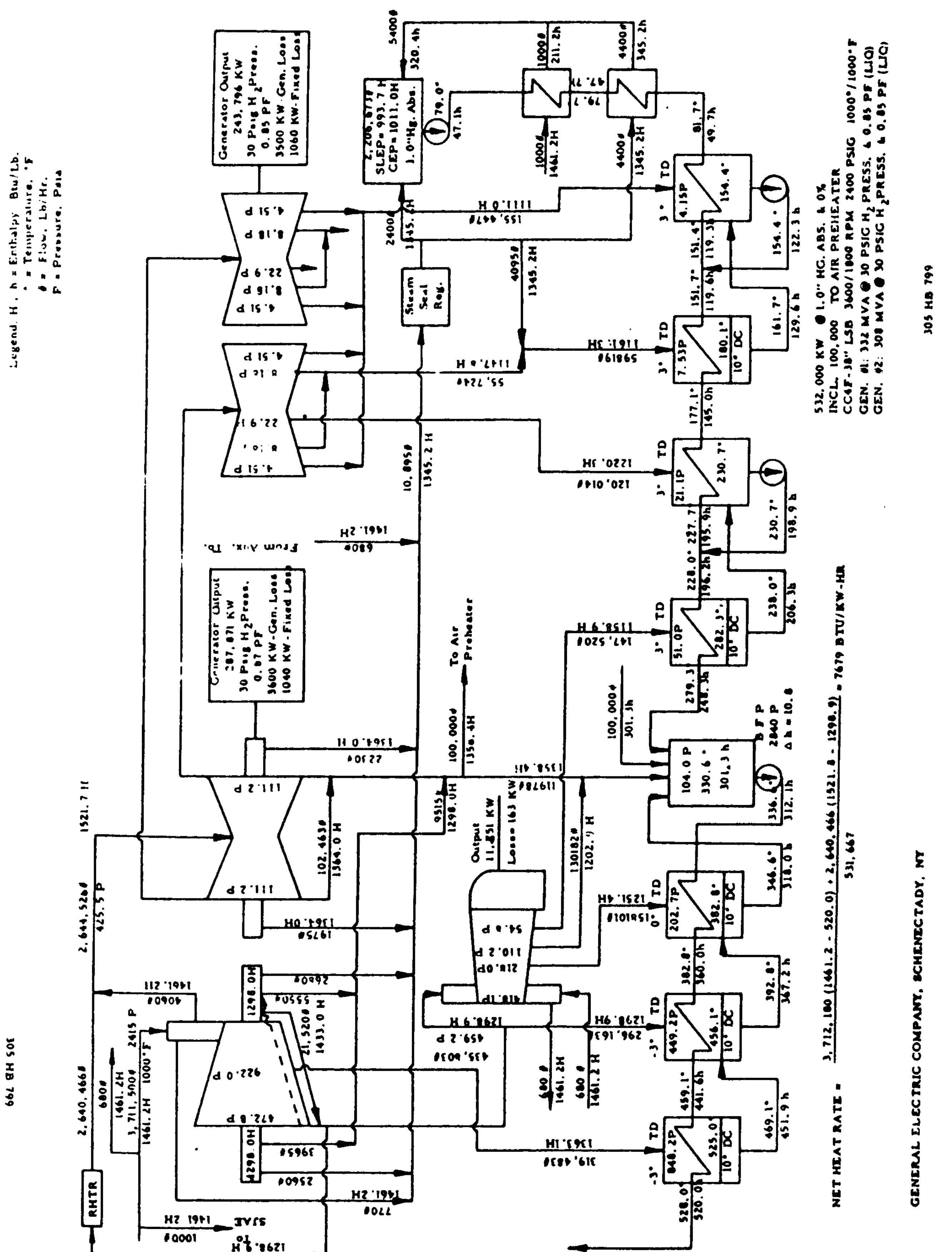

NET HEAT RATE =
GENERAL ELECTRIC COMPANY, SCHENECTADY, NY
305 HB 799

FIGURE 1

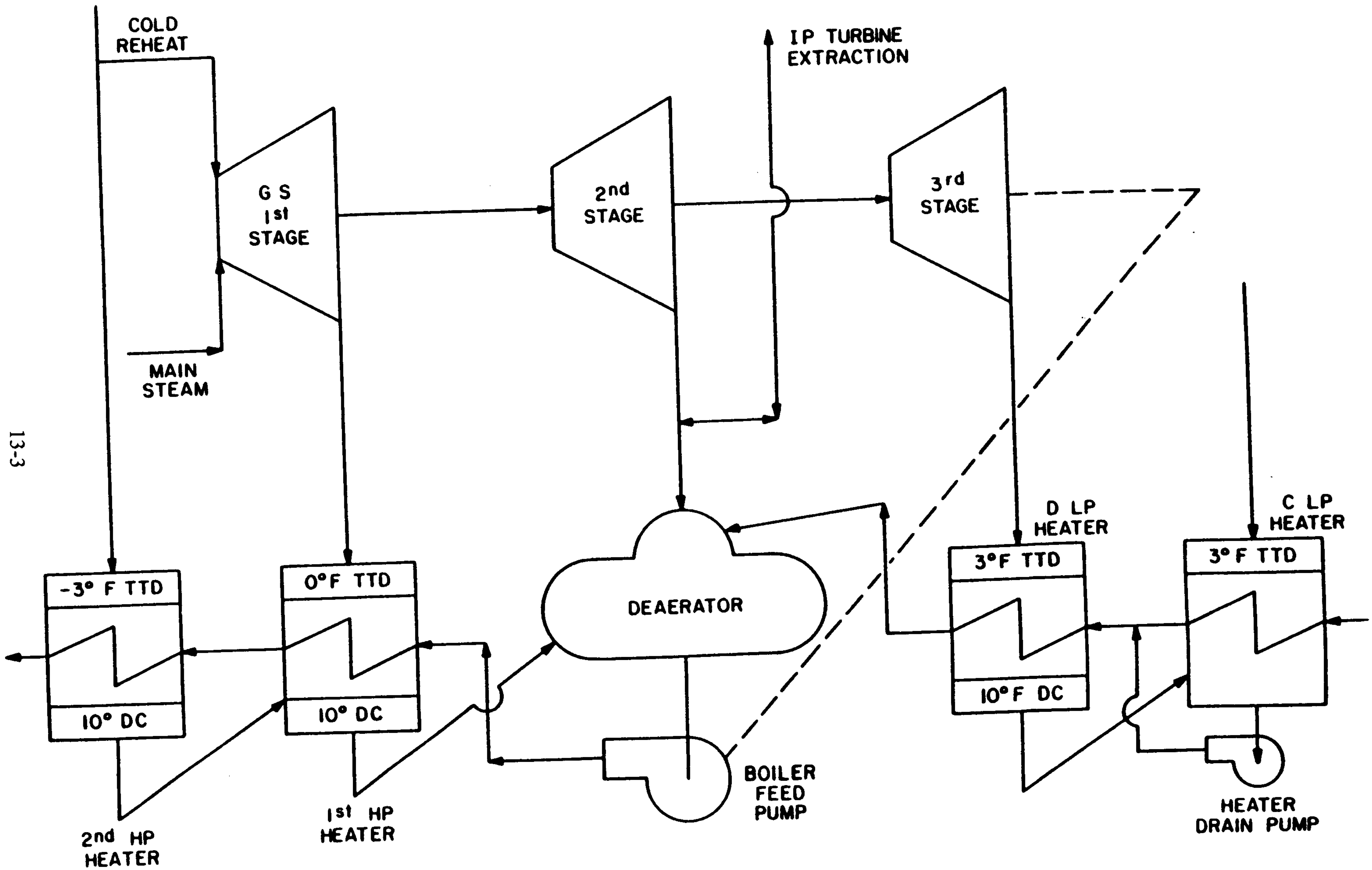


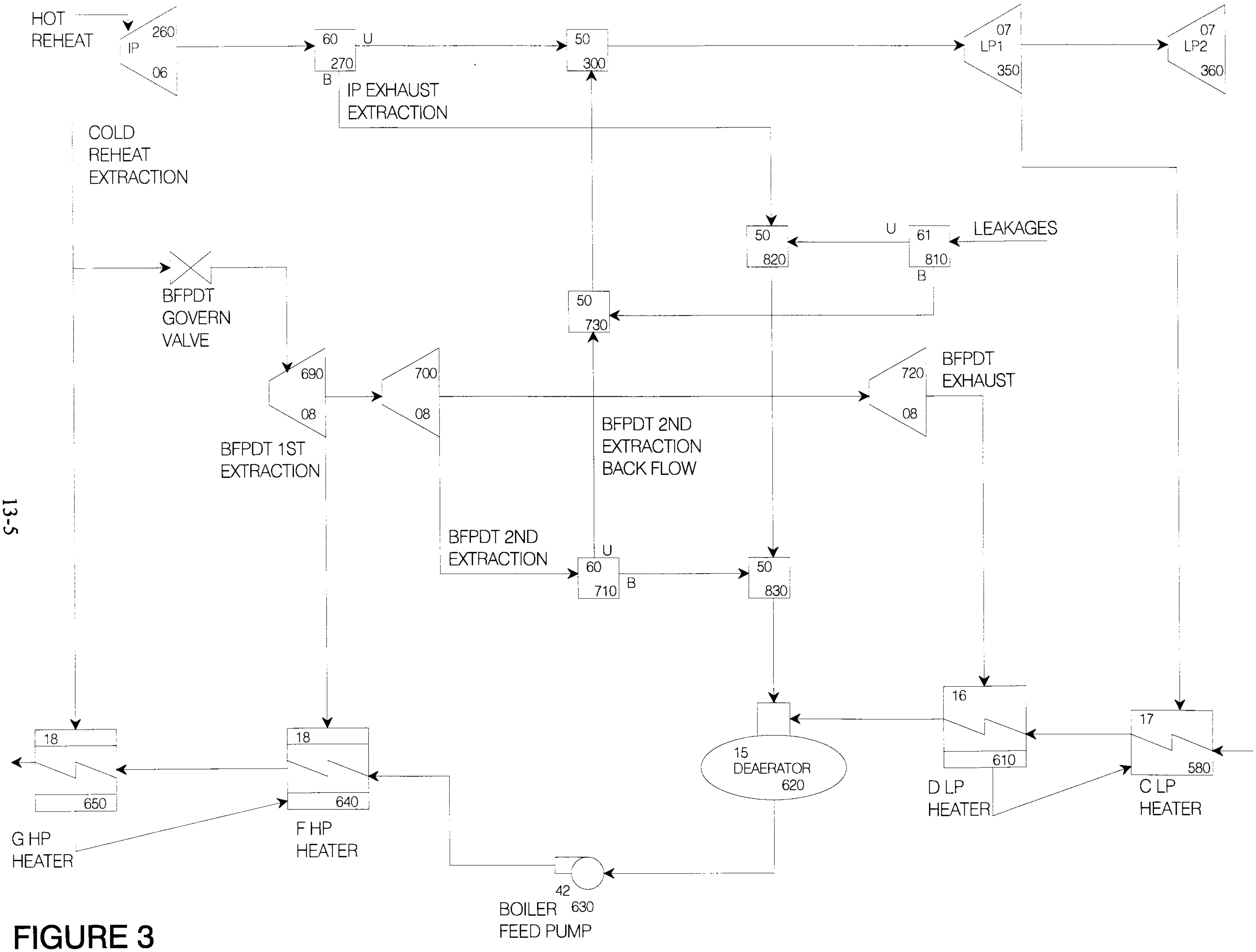
FIGURE 2: AUXILIARY TURBINE CONFIGURATION

must meet "D" heater's requirements exactly. The extraction from the first section of the BFPDT is the only steam supply to "F" heater as well. The second section of the BFPDT extracts to the "E" heater (the deaerator). This extraction flow is the steam remaining after the "F" and "D" heater demands are met. Because this flow may be either greater than or less than the deaerator requirements, a connection is made to the main turbine IP exhaust. If the flow from the second section of the BFPDT is less than required (as it is at high loads on WC4), additional extraction is drawn to the deaerator from the main turbine IP exhaust. When the flow is greater than required, the excess steam is sent to the IP turbine exhaust.

Figure 3 is a detailed diagram of the BFPDT section of the PEPSE model. A paper presented by Dave Koehler (Koehler, 1986) at the PEPSE Users Group Meeting in 1986 also dealt with this model. The method used in the paper was successful, but lacked the flexibility we need from the model today. The many operations and controls necessary to aid PEPSE's convergence constrained the usefulness of the model. Therefore, we attempted to design a method to generalize it.

After many unsuccessful attempts, we set up new control logic. Logic was entered to meet the thermal needs of heater #610 (DCA) by controlling the extraction flow of turbine #700. This computational process was somewhat indirect in that the flow being adjusted was the extraction steam flow from the upstream middle turbine stage group. This control scheme was successful at high loads, but would not converge at low loads.

The reason for the non-convergence was that the demand reference of FWH #610 was zero. Thus the FWH was forced to accept whatever flow it received in each iteration. Due to the downstream marching order of the solution, the competing demands further upstream are satisfied, computationally, before this last one. During some iterates the exhaust FWH (#610) received small amounts of steam. This drove the calculated drain enthalpy out of bounds, to negative values. The FWH logic (safety net) detected this and reset the drain enthalpy to 200 Btu/lbm in order to allow the computation to proceed and hopefully get past the cause of the trouble. This reset, being non-physical and disconnected from the cause/effect assumptions of the control, fed irrational information to the control. The control was thus confused and unable to move toward a solution. Thus the control slammed back and forth between the specified limits.


HOT
REHEAT
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260
06
60
270
U
B
IP EXHAUST
EXTRACTION
50
300
07
LP1
350
07
LP2
360
COLD
REHEAT
EXTRACTION
50
820
U
61
810
B
LEAKAGES
50
730
BFPDT
GOVERN
VALVE
690
08
700
08
720
08
BFPDT
EXHAUST
BFPDT 1ST
EXTRACTION
BFPDT 2ND
EXTRACTION
BACK FLOW
BFPDT 2ND
EXTRACTION
U
60
710
B
50
830
18
650
G HP
HEATER
18
640
F HP
HEATER
15
DEAERATOR
620
16
610
D LP
HEATER
17
580
C LP
HEATER
42
630
BOILER
FEED PUMP

FIGURE 3

3.0 Solution

Since the flow excursions and the drain condition reset were directly preventing convergence, any solution must address these two obstacles.

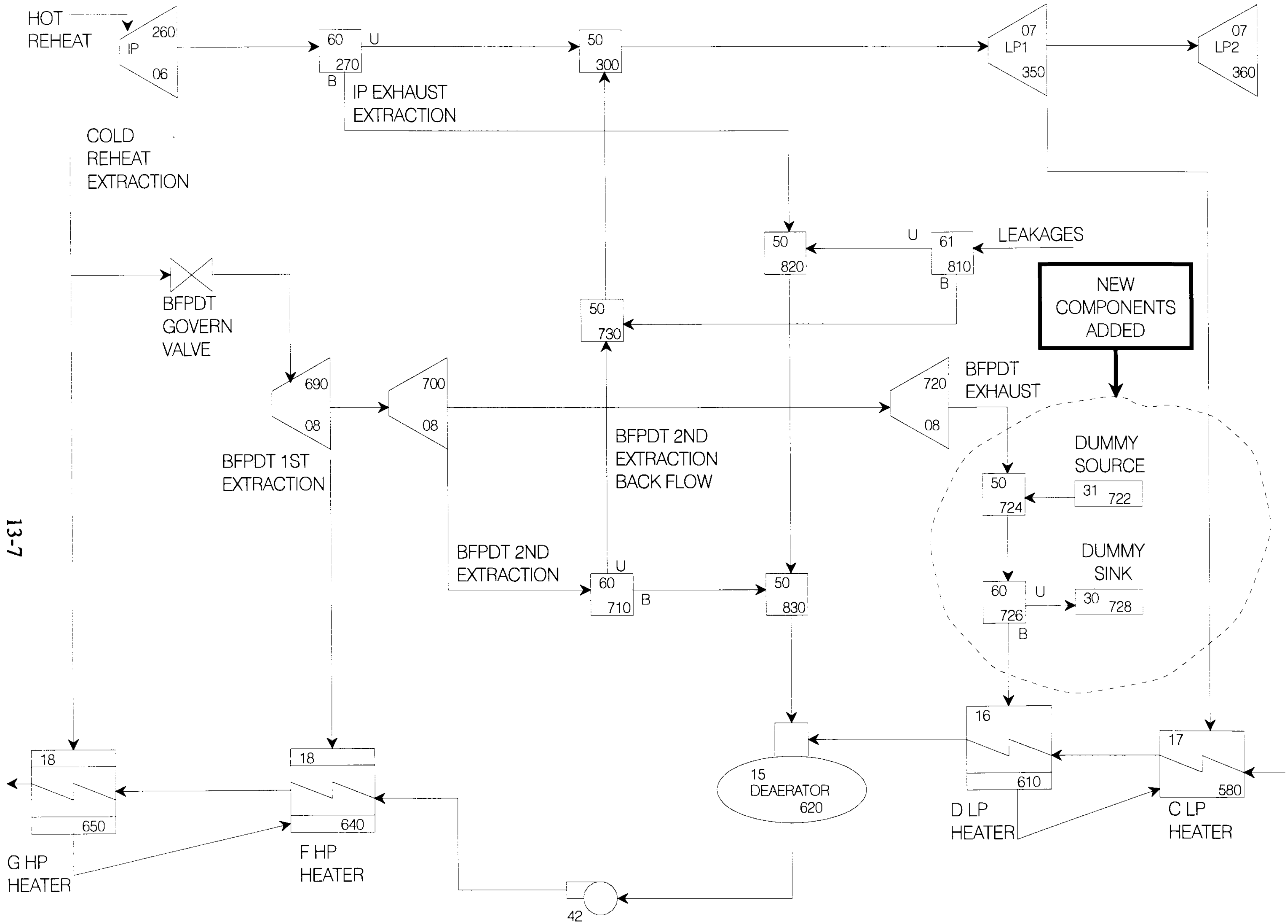
First, to prevent the reset, a demand splitter was installed in the line between the exhaust of turbine #720 and the shell inlet of heater #610 (see Figure 4). The B-port of this splitter feeds steam to the heater. The U-port sends excess steam to a dummy sink. In the final solution, the flow to this dummy sink must be adjusted so as to cause no net loss of steam from the system. The splitter was necessary because when a heater references a demand splitter, the drain condition is set as specified by the DCA. This avoided the reset.

The splitter added, as discussed above, can supply only (to the heater) an amount of flow less than or equal to the amount coming into the splitter. As modeled, this is still susceptible to irregularities in calculated flows further upstream.

To assure adequate steam for FWH #610, an extra (dummy) steam source and mixer was added in the line between the exhaust of turbine #720 and the splitter added in the first item above (see Figure 4). From the side, connected into the mixer, a very large, fixed excess amount of steam was supplied. The thermal condition of the steam was set to match the condition of the steam exhausted from the turbine. Operations were used for this purpose. This assured that there would always be enough steam of the right energy content to meet the need of the FWH, no matter what happened in iterations prior to convergence.

The next task was to nullify the impact of this dummy steam once convergence was reached. To do this it was necessary to make flow adjustments further upstream to ensure that the actual turbine exhaust steam was the right amount to meet the exhaust feedwater heater's steam demand.

Adjustment of the turbine's steam flow can be accomplished by application of controls or operations. We defined a control to adjust the flow extracted (control variable, x) at the upstream turbine component (#700). This indirectly adjusts the amount of exhaust steam flow. The goal of the control was to match the amount of excess steam dumped by the splitter (through the U-port to the sink) with the amount of excess steam that was sent to the mixer by the dummy steam supply. Thereby the dummy steam has no net effect on the converged system solution.



HOT
REHEAT
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U
B
IP EXHAUST
EXTRACTION
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07
LP1
350
07
LP2
360
COLD
REHEAT
EXTRACTION
BFPDT
GOVERN
VALVE
690
08
BFPDT 1ST
EXTRACTION
700
08
50
730
BFPDT 2ND
EXTRACTION
BACK FLOW
BFPDT 2ND
EXTRACTION
60
710
U
B
50
820
61
810
U
B
LEAKAGES
50
830
720
08
BFPDT
EXHAUST
NEW
COMPONENTS
ADDED
DUMMY
SOURCE
31
722
50
724
DUMMY
SINK
60
726
U
B
30
728
18
650
G HP
HEATER
18
640
F HP
HEATER
42
630
BOILER
FEED PUMP
15
DEAERATOR
620
16
610
D LP
HEATER
17
580
C LP
HEATER

FIGURE 4

This solution made it possible for the model to converge over the load range. The following is a partial data set that demonstrates the features.

```
**** ESTABLISH DUMMY STEAM SUPPLY AND SINK ****
707220  31  300.   31.5   1.0E6   0.0   1174.
707280  30
**** ESTABLISH MIXER TO MIX DUMMY STEAM WITH TURB 700 EXHAUST ****
707240  50  1
**** ESTABLISH DEMAND SPLITTER SUPPLYING HEATER 610 ****
707260  60  0.0   162000.0

**** REFERENCE #726 AS DEMAND FOR HTR 610 ****
706100  16  0  726  2  0.0  3.0   10.0  0.0

**** CONTROL EXTRACTION FROM TURBINE #700 TO GET FLOW
          MATCH FROM DUMMY SUPPLY AND TO DUMMY SINK. ****
840100  WEXTP,700, 0.0,100.0, 1.0, WW, 722,-1.0 ,WW,728
840105  5                    * ONLY APPLY CONTROL EVERY 5TH INTERVAL
840106  7                    * BEGIN THIS CONTROL ON THE 7TH ITERATION
840107  0.70                 * RELAXATION FACTOR = 0.70
840109 122000.0 138000.0  * SET LIMITERS FOR CONTROL VARIABLE "X"

**** SET "B" PORT MAX FLOW OF SPLITTER #710 EQUAL TO TURB #700
EXTRACTION FLOW  SO SPLITTER #270 CAN BE CALLED AS BACKUP DEMAND
SUPPLIER ****
880010  WEXTP , 700, EQL, WWDMAX, 710

*** OPERATIONS TO SET DUMMY AND SPLITTER ENTHALPY ***
881950  PP,721,  EQL,  PPVSC , 722
881960  XX,721,  EQL,  TTVSC , 722
881990  HH,-721, EQL,  HHFIXB, 726      * REDUNDANT CARD*
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4.0 Conclusion

The solution to this problem required careful collection of diagnostic information and a fairly extensive understanding of PEPSE's sometimes more subtle aspects. For example, years of experience have led to placement of a number of coded safety nets in PEPSE that are often helpful in getting troublesome calculations through a period of instability. In some instances these nets can also interfere with progress to a successful conclusion. The reset of the drain enthalpy to 200 Btu/lbm in this model is one example of this.

In this case, root cause analysis led us to the problem with this model's convergence. Once the two root causes were found (the drain enthalpy reset and the inadequate steam supply to heater #610 in early iterations), the solution was accomplished with basic PEPSE components and controls.

REFERENCES

1. Koehler, Dave, "PEPSE Modeling Three Units With Dual Extracting Steam Driven Boiler Feed Turbines", PEPSE Users Group Meeting, May 21, 1986.

2. Minner, G.L., Fleming, D.R., Rice, G.C., PEPSE Manual: User Input Description (Volume 1), 1993.

3. Commonwealth Edison Company, Will County Station Unit No. 4 Plant Equipment Manual, Turbine Generator Section Vol.2, 1963.