PEPSE Modeling Three Units with Dual Extracting Steam Driven Boiler Feed Turbines

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Dave Koehler
Commonwealth Edison Co.
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Abstract

During the years 1982 through 1985 Commonwealth Edison Co. developed a working PEPSE model for three 550 megawatt fossil units. Will County Station Unit 4 and Joliet Station Units 7 & 8 (sister units), both have dual extracting steam turbine driven boiler feed pumps. The turbines are either supplied with cold reheat or primary throttle steam. The feed pump turbines exhaust to the feedwater heater below the deaerator. Additionally, the steam driven turbines have two extractions which supply the deaerator and first high pressure heater. The second stage extraction, depending upon the load, can either supply the deaerator and/or backflow some of its extraction to the IP exhaust. The deaerator at high loads can also receive extraction from the main IP turbine exhaust. This paper discusses the extra logic needed to PEPSE model extracting boiler feed pump turbines.

Introduction

Steam driven turbine drives are common prime-movers in the utility industry today. One of their main applications is to drive large boiler feed pumps. These drive units can be made to have larger horsepower ratings than electric motors. Secondly, they don't need the extra investment of fluid couplings. Some auxiliary turbine drives tend to be straight condensing design. They require steam at some intermediate turbine pressure and exhaust it to a condenser. More complicated drive turbines have extractions on them, and may not exhaust to the condenser. This paper will discuss PEPSE modeling problems as applied to these types of turbine drives.

Background

Commonwealth Edison Company with headquarters located in Chicago, Illinois is a large midwest utility having over 19,161 MW of generating capacity in Northern Illinois. Edison serves more than three million customers with an estimated population of eight million. The service area is 11,525 square miles which includes Chicago and 400 other incorporated communities. We have 9 large nuclear units, having between 800 and 1100 MW capacity each, and 3 more units still under construction. Presently, Commonwealth Edison has 8,127 MWs of nuclear capacity. Those additional nuclear units will add another 3,360 MWs capacity by the end of 1988. Except for 1,331 MWs fast-start gas turbine peakers, the remaining 9,703 MWs is fossil production. (This includes our share of 624 MWs pumped hydro storage at Ludington, Michigan.)

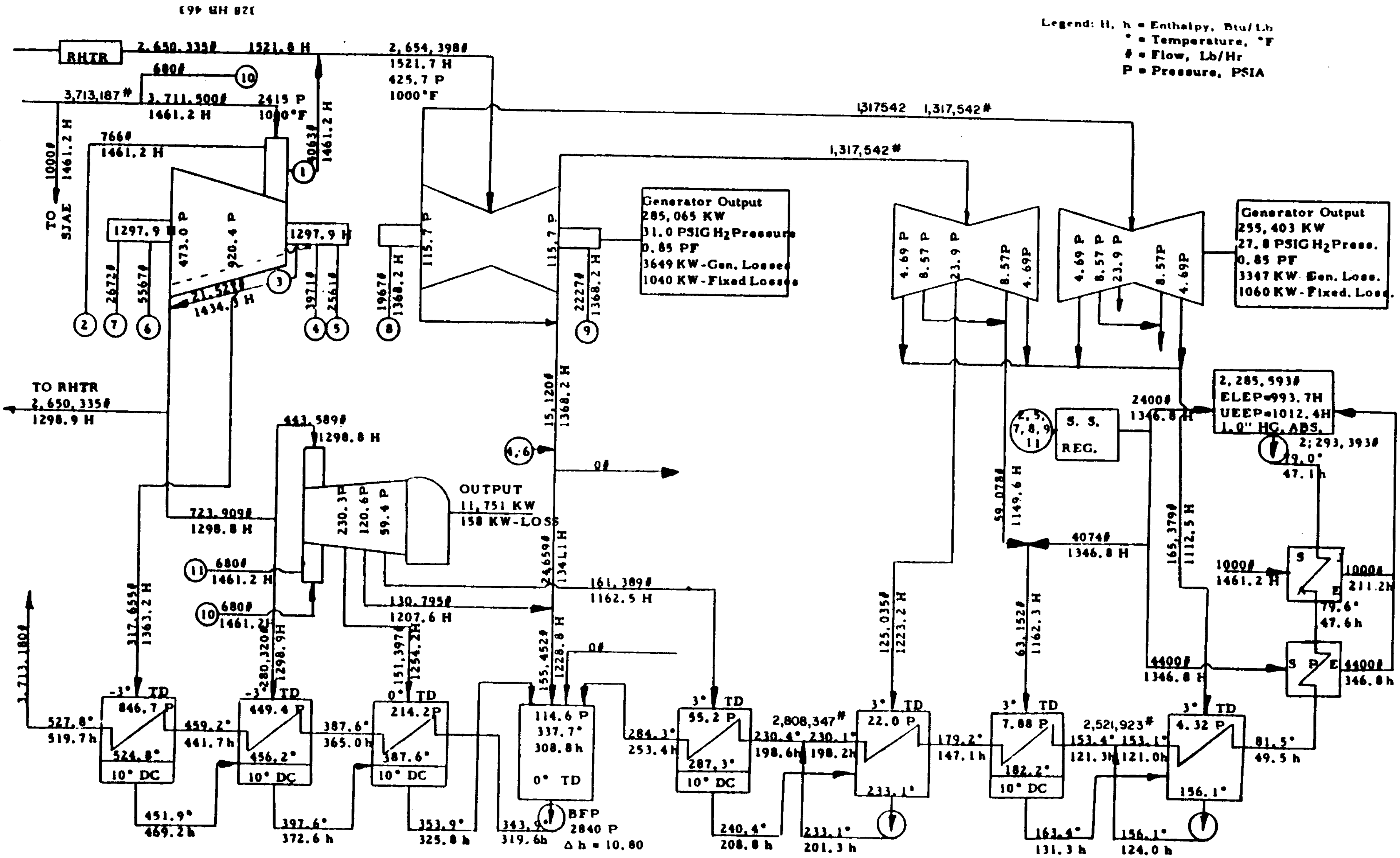
The fossil division is composed of ten generating stations having 24 units with all but two stations (4 units) located in the service territory. Five of these units are 550 MW capacity oil fired units. (Our total oil fired generating capacity is 2750 MWs.) This paper will discuss PEPSE modeling problems at three coal fired fossil units.

Three fossil units have complicated turbine drive units with multiple extractions. Located at Joliet, Illinois are two identical Westinghouse cross compound design units, with 2415 psia throttle pressure, 1000/1000 ^{o}F superheat/reheat temperatures, and 7 stages of feedwater heating. Their nameplate rating is 580 MW. The third unit located at Romeoville, Illinois is a General Electric design with a 532 MW rating. (See Figure 1) The Will County Unit has the same throttle and reheat conditions but has 8 stages of feedwater heating. The eight heater draws extraction steam from the fourth stage of the high pressure turbine.

All three units have auxiliary turbine drives with three sections and two extractions. The first extraction supplies the first high pressure (F heater) heater. The second extraction supplies steam to the deaerator (called "E" heater). The deaerator also receives steam from the main IP turbine exhaust at high loads. At low loads part of the second turbine drive extraction backflows to the IP turbine exhaust. The auxiliary turbine third stage exhausts into the top low pressure heater (D heater) just below the deaerator. The exhaust can flow to "C" heater or the condenser if the top low pressure heater is out of service. A simplified drawing of the auxiliary boiler feed pump turbine is shown in figure 2.

Auxiliary Turbine Model Layout

Modeling the auxiliary turbine involves using three type eight general turbines. A detailed diagram of the PEPSE



NET HEAT RATE $= \frac{3,712,180\,(1461.2 - 519.7) + 2,650,335\,(1521.8 - 1298.9)}{540,460} = 7560$ BTU/KW-HR

532,000 KW @ 1.0" HG. ABS., 0% MU
INCLUDING 100,000# TO AIR PREHEATER
CC4F-38" LSB 3600/1800 RPM
2400 PSIG 1000°/1000°F
GEN. #1: 332 MVA @ 30 PSIG H_2 PRESS. & 0.85 PF(LIQ)
GEN. #2: 308 MVA @ 30 PSIG H_2 PRESS. & 0.85 PF(LIQ)

328 HB 463

GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK

FIGURE NO. 1: WILL COUNTY UNIT 4 VENDOR HEAT RATE

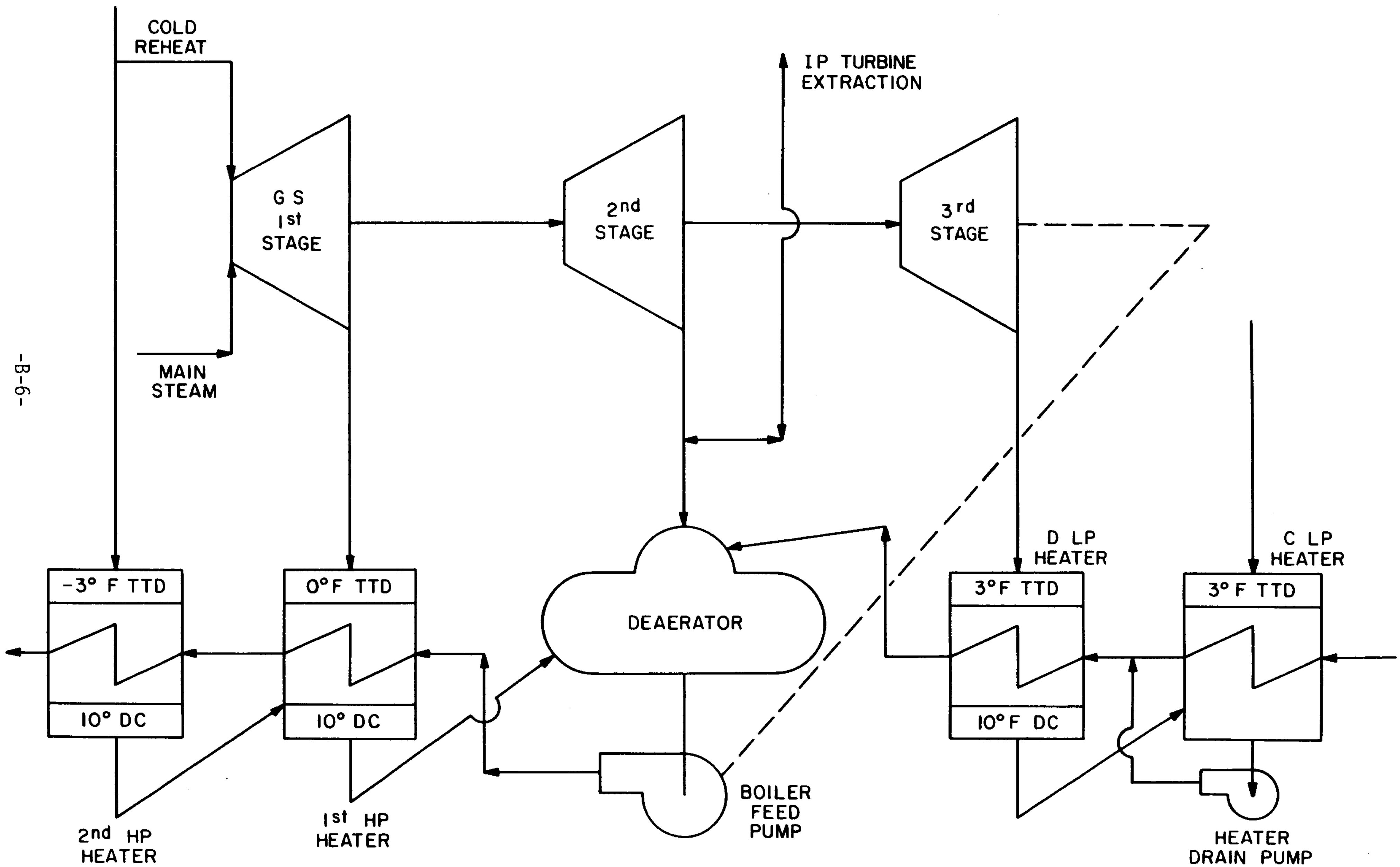


FIGURE 2: AUXILIARY TURBINE CONFIGURATION

auxiliary turbine model is shown in figure 3. Three turbines stages drive a type 42 boiler feed pump (component #670). The first turbine stage (component #690) simulates a governing stage. The second stage (component #700) goes from the first extraction to the second extraction point. The second stage simulates an IP turbine. The third stage (component #720) goes from the second extraction to the turbine exhaust (stream #725). The third stage simulates no particular turbine design type. A type 61 fixed flow splitter (component #270) and (stream #277) simulate an extraction line from the IP turbine. This acts as a secondary source of steam for the deaerator (component #620). The deaerating heater is referenced to the second steam driven turbine (component #700). Under normal conditions a type 52 mixer would be used to combine the two extractions together before entering the deaerator. Auxiliary turbine exhaust feeds the top low pressure heater just below the deaerator (component #610). This is commonly referred to as "D" heater. This heater is not referenced to the last stage for extraction updating.

A type 52 extracting mixer could not be used to combine the two extractions. The extraction flows are not equally divided between the two turbine stage groups. At high loads the steam driven turbine supplies 90% of the extraction steam and the remaining 10% supply comes from the IP turbine. Secondly, at low loads the IP turbine supplies no steam. The steam driven turbine returns steam to the main IP turbine exhaust through the IP turbine exhaust extraction line. The IP turbine extraction line has no extraction check valve in it. Thirdly, a type 52 mixer cannot be used on the last stage group of the turbine.

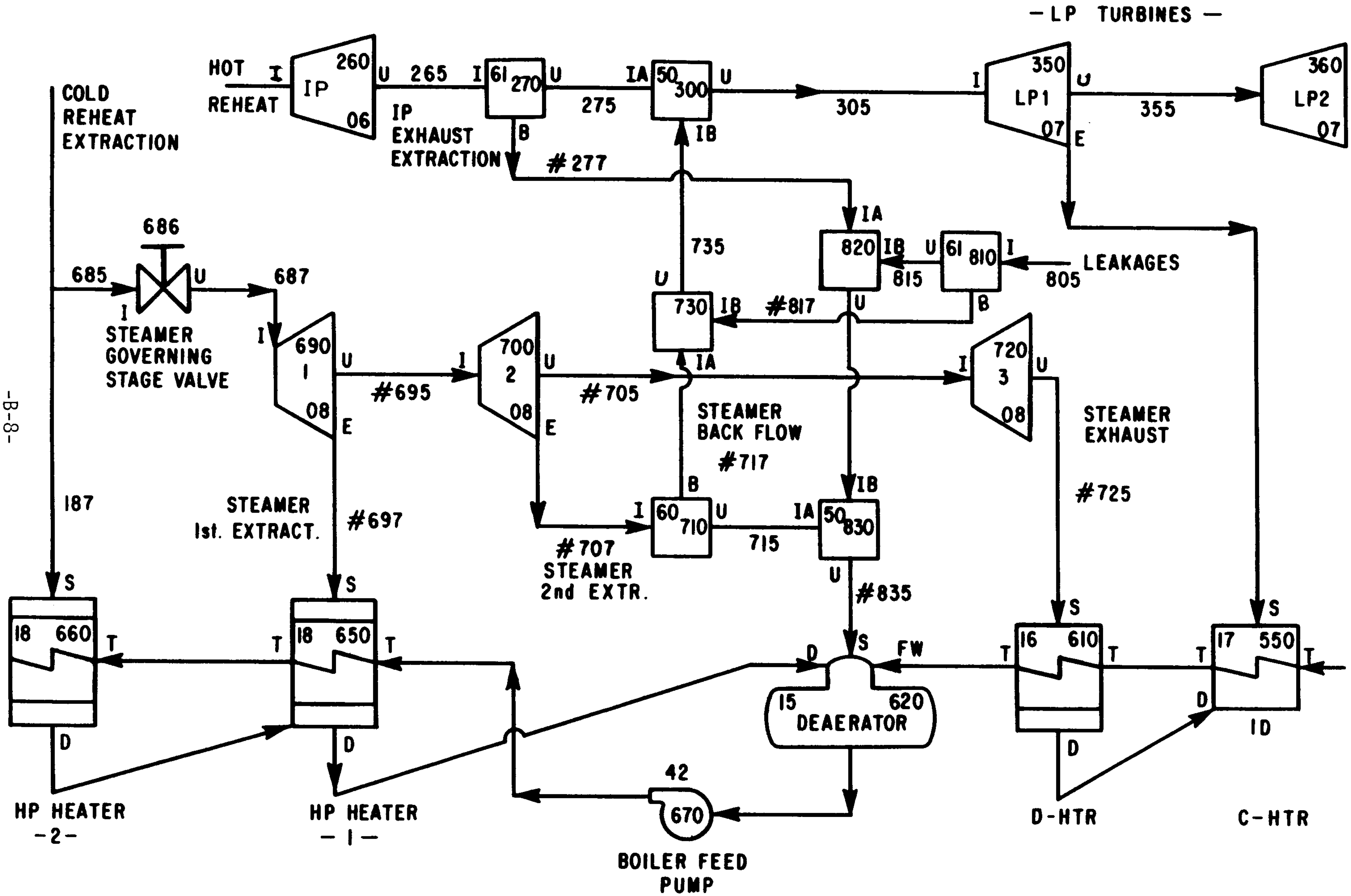


FIGURE 3: PEPSE MODEL OF AUX. TURBINE CONFIGURATION

Auxiliary Turbine Operation:

As shown in Figure 3, fixed flow splitters, and mixers are used to backflow excess steam at low loads from the second stage turbine extraction line (stream #707). A type 61 splitter (component #710) is located on the extraction line of the second auxiliary steam turbine stage (component #700). It is used to backflow excess steam to the IP turbine exhaust. A fixed flow type 61 splitter (component #810) located on the leakage totalizer line to the deaerator (stream #817) backflows turbine leakages at low loads. Two type 50 mixers combine second stage backflow (stream #717) and leakage backflow (stream #817) at (mixer #730). Mixer #730 sends it to the main turbine stream line via (stream #735) to another mixer (component #300).

A fixed flow splitter (component #270) located between the IP and LP turbine supplies the deaerator extra extraction (stream #277) at high loads. Extra IP extraction combines with the leakages going to the deaerator (stream #815) at a type 50 mixer (component #820). It further combines with the second stage extraction at another type 50 mixer (component #830). From that mixer all three flows go to the deaerator through stream #835.

Actual Working Solution:

This is not a straight forward application of PEPSE for the following reasons. First, flow going through the last auxiliary steam driven turbine stage is dependant solely upon extraction needs of the top low pressure heater ("D" heater: component #610). Thus, steam flow through the last stage (component #710) is limited by the amount of feedwater heating done by "D" heater. The amount of third stage auxiliary turbine pump work done is secondary. If this were not the case, "D" heater would tend to flash from too much steam sent to it.

The PEPSE model can be solved using only schedules: a schedule each to handle leakage backflow, IP turbine extraction, and second steam driven turbine backflow. The schedules are referenced against main turbine throttle flow. However, the model would tend to be quite rigid. For example, the PEPSE model could not handle individual heaters or entire high pressure heater strings out of service. The model would not accurately account for off design conditions such as low main turbine throttle pressure, temperature, and reheat conditions. The three type 8 turbines (components #690, #700, and #710) are very unstable unless shell pressures and enthalpies are input (IPCASE No. 5) for each run. Scheduling the pressure and enthalpies over the load range was not very successful.

The actual PEPSE working solution for handling this configuration is divided into six parts. First, there is the PEPSE configuration and logic for thermally balancing "D" heater. Second, there is the method for calculating the amount of deaerating heater extraction. Third, is the configuration and logic to handle combined extraction leakage flows into the deaerator. Fourth, is the logic for IP turbine extraction. Fifth, is the backflow logic for handling auxiliary turbine second extraction flow to the IP turbine. Sixth, is the calculations required for the auxiliary steam driven turbine and boiler feed pump to follow the predicted performance curves.

1. "D" Heater Routine (Auxiliary Turbine Exhaust)

The "D" heater routine shown on page 12, performs a heat balance around the top low pressure heater. Steam flowing through the last steam driven turbine stage (component #720) depends on feedwater heating demands of the top low pressure heater ("D" heater). The last turbine stage merely utilizes available energy in extraction steam going to "D" heater. The routine starts out by calculating an enthalpy rise across the condensate in "D" heater. Next a drain enthalpy is calculated based on the actual saturation temperation at the heater shell pressure and a ten degree drain cooler approach. If desired a different drain cooler approach could have been used. From there, expected shell side enthalpy rise is calculated for "D" heater. The ratio of condensate enthalpy rise to expected, shell side extraction drop is calculated. This ratio is multiplied by actual condensate flow through "D" heater. The expected flow through the last stage of the steam driven turbine is calculated. The calculated extraction flow is compared to actual flow going to "D" heater shell. The resultant difference, called the error, is divided by two (It has a 0.5 relaxation factor.) The error is added to the second stage auxiliary turbine extraction flow, and results in the corrected second stage extraction flow. These operations determine the flow to the last turbine stage.

2. Deaerator Extraction Logic Routine:

The second extraction is the adjusting point of the auxiliary turbine. It receives the correcting factor from the

D Heater Routine

1.) Calculate condensate enthalpy rise across D heater:

HH, 615 SUB, HH, 605, OPVB, 4

2.) Calculate "D" heater drain temperator based on a 10 Degree F drain cooler approach (DCA):

OPVB,2, ADD, TT, 605, OPVB, 5

OPVB,2 = 10.0

3.) Calculate "D" heater drain enthalpy based on shell pressure (above) drain temperature:

PP, 725, PTH, OPVB, 5, OPVB, 6

4.) Calculate expected enthalpy drop in "D" heater shell side:

HH, 725, SUB, OPVB, 6, OPVB, 7

5.) Take the ratio of "D" condensate enthalpy rise to expected shell side extraction drop "D":

OPVB, 4, DIV, OPVB, 7 OPVB, 8

6.) Multiply the ratio in step 5 by the condensate flow to get the calculated auxiliary turbine exhaust flow:

OPVB, 8, MUL, WW, 605, OPVB, 9

7.) Take actual exhaust flow and subtract the calculated extraction steam flow to get the error:

WW, 725, SUB, OPVB, 9, OPVB, 10

8.) Divide the error by 2 (0.5 relaxation factor)

OPVB, 10, MUL, OPVB, 3, OPVB, 11

OPVB, 3 = 0.5

9.) Add the error to actual auxiliary turbine second extraction. The answer is the "corrected second extraction flow".

WW, 707, ADD, OPVB, 11, OPVB, 12

OPVB, 12 = Corrected Second Stage Extraction Flow

"D" heater routine to adjust steam flow to the last stage. The second stage extraction must help satisfy deaerator heating requirements.

Second stage extraction flow is precisely controlled so flow to the last stage will satisfy feedwater heating requirements in "D" heater. Deaerator feedwater heating extraction requirements may be different than the auxiliary turbine second extraction is supplying the deaerator. If the steam requirement is larger, then the balance has to come from turbine leakages and IP turbine exhaust extraction. At low loads second stage turbine extraction is greater than deaerator heating load. No IP turbine extraction or turbine leakage is necessary. Some second stage auxiliary turbine extraction must be backflowed to the main turbine.

At low load more cold reheat steam is needed due to its lower pressure and auxiliary turbine operating efficiency. These constraints for flow and pump work requirements make added problems for the deaerator energy balance. This is resolved by using the IP turbine extraction line as an "open avenue" for supplying additional or returning excess extraction steam to the main turbine. In the actual cycle the IP turbine extraction line does not have a check valve in it. The extraction steam can flow either way.

Before any additional IP extraction is needed, fixed turbine leakages are utilized. This is accomplished by the following set of operations. Total deaerator shell flow is subtracted from corrected second stage extraction flow (shown on page 14). Deaerator shell flow is comprised of:

DEAERATOR EXTRACTION LOGIC ROUTINE

1.

Corrected Second Stage Auxiliary Turbine Extraction Flow	-	Total Deaerator Shell Flow: 1. Second Stage Turbine Extraction Flow 2. IP Turbine Extraction 3. HP & IP Leakage	=	Actual Deaerator Extraction Adjustment D.E.A.

High Loads: IP Extraction & Leakages to Deaerator; D.E.A. is negative.

Low Loads: IP Extraction & Leakages to Turbine; D.E.A. is Positive.

2. Take the absolute valve of D.E.A.: [D.E.A.]

3. $\frac{[D.E.A.] - D.E.A.}{2}$ = At high loads the equation equals the amount of additional steam necessary to satisfy deaerator heating load.

0 At low loads the equation equals zero. The actual difference was negative (meaning the deaerator needs less steam than the second extraction is sending.

second stage turbine extraction, IP turbine extraction, and HP & IP turbine leakages dumping into the deaerator. The resultant from equation 1 should be the deaerator extraction adjustment (D.E.A.). At high loads this adjustment is the additional IP turbine extraction and leakages necessary. At low loads it is the second stage turbine extraction and leakage to be backflowed. The absolute value of the deaerator extraction adjustment is taken (equation 2), subtracted from itself and then divided by two (equation 3). Two things can happen: If D.E.A. was positive (meaning the deaerator needs less steam then what the second extraction is sending), equation 3 will be zero. Or the answer in equation 3 will represent the amount of additional steam necessary for deaerator heating load. Please note the main purpose of the auxiliary turbine second extraction is to regulate flow to the third stage. The deaerator feedwater heating done by the second extraction is the secondary.

3. <u>HP & IP Turbine Leakage Logic</u>

The previous section determined if additional extraction steam is necessary for the deaerator. This section deals with how much turbine leakage will be necessary. This logic also calculates the leakage split between the IP turbine and deaerator.

The first turbine leakages on both, ends of the high and intermediate pressure turbines are dumped into the deaerator during normal high load conditions. Below 70% of full turbine load part of the leakage is sent back to the IP turbine exhaust. The following logic to handle this in the model is shown on page 16. First, additional steam for deaerator heating load : D.E.A. (Deaerator Extraction Adjustment) is subtracted from

HP & IP TURBINE LEAKAGE LOGIC

1. | | | | |
|---|---|---|---|
| HP & IP Turbine Leakage Flow To The Deaerator (Leakages) | Subt. | Amount of Additional Steam Necessary To Satisfy Deaerator Heating Load (D.E.A.) | = Difference (DIFF) |

2. DIFF is compared to zero in a Binary IF (BIF) operation:

DIFF BIF:0 = X

"X" acts as a logic gate signal for determining whether to back flow turbine leakages to the IP turbine exhaust instead of sending them to the deaerator.

If DIFF is POSITIVE BIF RESULTANT = ONE

If DIFF is NEGATIVE BIF RESULTANT = ZERO

3. The binary if resultant "X" is multiplied by DIFF. The answer is the amount of steam leakage to be backflowed to the IP turbine.

DIFF multiplied by "X" = DIFFC

LOGIC SIGNAL

WHEN	BIF (X) RESULT:	STATUS
DIFF GREATER than 0	(1)	Turbine leakage is enough or more than enough to cover additional deaerator feedwater heating requirements.
DIFF LESS than 0	(0)	Turbine leakage is not enough to cover additional deaerator feedwater heating requirements.

4. Take the ABSOLUTE Value of the leakage difference [DIFFC]:

5. The absolute value of the leakage difference [DIFFC] is used for the WWFIXB variable in component #810.

[DIFFC] = WWFIXB, 810

This is the amount of turbine leakage to be backflowed to the IP turbine exhaust. At high loads [DIFFC] equals 0 whereas at low loads [DIFFC] equals leakage backflow amount.

actual turbine leakage flow. Second, the answer (DIFF) is compared to zero in a binary if statement. If the leakage was greater than the difference then the answer (X) will be one. If the leakage was less than the difference (DIFF), then the answer (X) will be zero. The answer (X) is used as a "logic gate" for signaling backflow leakage to the IP turbine exhaust. In the third step, the difference (DIFF) is multiplied by the resultant from the binary if operation. This amount is either zero or the leakage (DIFF) that should be backflowed to the IP turbine exhaust. The absolute value is taken to insure a positive number for the backflow leakage splitter (component #810). At certain loads only some of the leakage is backflowed.

4. <u>IP Turbine Extraction Logic</u>

At high loads auxiliary turbine second extraction and leakages do not supply enough steam to the deaerater for feedwater heating. Extra steam for the deaerator is supplied by the IP turbine. This section determines the extra extraction to be supplied by the IP turbine.

As shown on page 18 and 19, the shaft packing leakage sent to the deaerator is subtracted from the adjustment to the deaerator flow. At high loads the value "IPEXT" is positive representing the need for IP turbine extraction (equation 1). At low loads it is negative signifying IP turbine extraction is not necessary. A binary if operation is used on the result (equation 2). The answer is one for a positive "IPEXT", and zero for a negative "IPEXT." The binary if result gets multiplied by "IPEXT", the answer is zero or the amount of additional IP extraction steam necessary to satisfy deaerator feedwater heating (equation 3).

IP TURBINE EXTRACTION LOGIC

1.	Amount of Additional Steam Necessary To Satisfy Deaerator Heating Load (D.E.A.)	SUBTRACT	HP & IP Turbine Leakage Flow To Deaerator (Leakages)	=	IPEXT (IP Turbine Exhaust Extra Extraction)

IPEXT Represents the extra extraction needed for the deaerator to be satisfied.

IF IPEXT is GREATER than 0	Turbine leakages not enough to satisfy deaerator feedheating. IPEXT indicates the amount of IP turbine extraction necessary.
IF IPEXT is LESS than 0	IP turbine extraction not necessary. Too much turbine leakage is being supplied to the deaerator for feedwater heating. IPEXT indicates the amount of leakage to be backflowed (after the absolute value of IPEXT is taken) to the IP turbine exhaust.

IP TURBINE EXTRACTION LOGIC

2. Next "IPEXT" is compared to zero in a Binary IF (BIF) operation.

IPEXT BIF : 0 = Y

"Y" acts as a logic gate signal for determining whether to add extra IP turbine extraction.

LOGIC SIGNAL

When	BIF (Y) Result	Status
IPEXT Greater than 0	(1)	Turbine leakage is not enough to cover additional deaerator feedwater heating requirements. IP turbine extraction is necessary.
IPEXT Less than 0	(0)	Turbine leakage is enough or more than enough to cover additional deaerator feedwater heating requirements. No IP turbine extraction is necessary. Note: IPEXT in this case actually indicates the amount of leakage to be backflowed.

3. The binary if resultant Y is multiplied by IPEXT. The answer (IPEXTC) is the amount of IP extraction necessary.

IPEXT multiplied by "Y" = IPEXTC

Synopsis

IP Turbine Ext. Logic:	Leakage Logic:	Action:
IPEXT GT. 0 Y = 1;	DIFF LT. 0 X = 0	IP extraction; no leakage backflow.
IPEXT LT. 0 Y = 0;	DIFF GT. 0 X = 1	No IP extraction; leakage backflow.

4. Here the IP Extraction to the deaerator is compared to 20,000 lbm. The lesser of the two gets input into WWFIXB, 270:

IPEXTC, MIN, 20,000lbm, WWFIXB,270

For added stability the answer is compared to 20,000 lbm. This is the maximum amount that could be supplied by the IP turbine to the deaerator. This result is fed into (WWFIXB variable) the fixed flow splitter #270 on the main turbine stream line. (equation 4)

5. <u>Auxiliary Turbine Second Extraction Backflow Logic</u>

At low loads no IP turbine extraction, is used. Additionally some auxiliary turbine second extraction is backflowed to the main turbine. The following logic on pages 21 and 22 determines how much second extraction should be backflowed.

Total deaerating heater shell flow is subtracted from the second extraction corrected flow. The answer is called the deaerator extraction adjustment (D.E.A.). At high loads D.E.A. is negative because the deaerator needs more extraction than the second extraction can supply. On the other hand, at low loads, D.E.A. is positive because the auxiliary turbine second extraction is supplying more steam than the deaerator needs for feedheating.

Next, the absolute value of the deaerator extraction adjustment (D.E.A.) is taken (equation 2). Third, subtract D.E.A. from the absolute value of D.E.A.. The answer from equation three is then divided by two (equation 4). In the fifth equation the normalized deaerator extraction adjustment is added to the actual deaerator adjustment. The answer is the second stage backflow adjustment. At high loads there is not enough second stage extraction steam going to the deaerator and D.E.A. is negative. When D.E.A. is added to the normalized value the answer is zero. At low loads there is too much second turbine extraction going back to the deaerator. D.E.A. is then positive. The answer is the second extraction steam to be backflowed.

AUXILIARY TURBINE SECOND EXTRACTION BACKFLOW LOGIC

1.	Second Extraction Corrected Flow	–	Total Deaerating Heater Shell (Extraction) Flow	=	Deaerator Extraction Adjustment (D.E.A.)

Note:

At high loads deaerator extraction adjustment is <u>negative</u> because the deaerator needs more extraction steam than the second extraction can supply.

On the other hand, at low loads deaerator extraction adjustment (D.E.A.) is <u>positive</u> because the second extraction supplies more extraction than the deaerator needs.

2. Take the absolute value of the deaerator extraction adjustment: [D.E.A.]

3. Subtract D.E.A. from the absolute value of D.E.A.

   [D.E.A.] – D.E.A. = 0 or Twice D.E.A.

At <u>High</u> load equation three:

D.E.A. – (-D.E.A.) = 2 D.E.A.

At <u>Low</u> Loads:

[D.E.A.] – D.E.A. = 0

4. Take the answer from step three and divide by two:

$$\frac{[D.E.A.] - D.E.A.}{2} = \begin{cases} COR.D.E.A.: & \text{High loads} \\ 0: & \text{Low loads} \end{cases}$$

5. Add the actual D.E.A. (from eqn. 1) to the corrected difference (from eqn. 4) and supply the answer to WWFIXB splitter 710.

D.E.A. + COR.D.E.A. = Amount of Second Auxiliary Turbine Extraction to be sent to the IP turbine exhaust.

At low loads:

(There is too much second auxiliary turbine extraction steam going to the deaerator)

D.E.A. + 0 = Second Auxiliary Turbine Extraction Back Flow Amount

At High Loads: (D.E.A. is negative)

(There is not enough second auxiliary turbine extraction steam going to the deaerator)

D.E.A. + COR. D.E.A. = 0

= Second Extraction Back Flow Amount

6. Pump and Turbine Performance Curves

Before performance curves can be used, the flow has to be checked to determine whether boiler feed pump flow is greater than half the maximum flow per pump. The curves are given per individual pump flow and not total boiler feed pump flow. This is accomplished by taking total boiler feed pump suction volume flow rate (cubic ft/hr) and dividing it by two (equation one on page 24). Next half the maximum flow per pump is compared (using a BIF operation) to half the actual flow (equation 2). The resultant will be zero if half the maximum flow per pump is less than half the actual volume flow per pump (equation 3). The answer will be one if half the maximum flow for one pump is greater than the actual flow (equation 4). The binary if resultant is multiplied by half the total volume flow (equation 5). The resultant will be zero or one half the actual volume flow. The resultant is then added to one half the actual volume flow rate (equation 6). This will result in the total volume flow when the pump flow is less than the two pump minimum (equation 7). It will be one half the actual flow when it is over the minimum amount for two pumps (equation 8).

Unlike the main turbines which run at constant speed, the auxiliary turbine is a variable speed turbine operating between 4300 - 5300 rpm. As a consequence this complicates the turbine performance curves. Except for the first HP turbine stage and the last LP turbine stage of the main turbine the efficiency curves and pressure ratios are relatively constant throughout the entire load range. In the case of a variable speed machine the pressure ratios and

BOILER FEED PUMP FLOW CHECK:

(1)	Actual Boiler Feed Pump Suction Volume Flow Rate	DIVIDE BY 2	=	1/2 Actual Volume Flow
(2)	1/2 Max Volume Flow Per Pump	BIF 1/2 Actual Flow	=	Resultant:(0,1)

(3) WHEN	1/2 Max Volume Flow Per Pump	Less Than	1/2 Actual Volume Flow	BIF Resultant = 0
(4) WHEN	1/2 Max Volume Flow Per Pump	Greater Than	1/2 Actual Volume Flow	BIF Resultant = 1

When BIF resultant = <u>Zero</u>; two pumps are required

When BIF resultant = <u>One</u>; only one pump is required

(5)	0 or 1	<u>Mult. By</u>	1/2 Actual Volume Flow	=	Zero or 1/2 Actual Volume Flow

(6) Answer from equation 5 + 1/2 Actual Volume Flow = Pump Flow for Curve

(7) When 1/2 Max Volume Flow Rate is Greater Than 1/2 Actual Volume Flow (Equation 4):

1/2 Actual + 1/2 Actual = Actual Volume Flow (One pump flow range)

(8) Or When 1/2 Max Volume Flow Less Than 1/2 Actual Volume Flow (Equation 3):

1/2 Total + 0 = 1/2 Actual Volume Flow (One pump flow range) efficiencies change over the load range. The pressure ratio is a function of flow. The efficiency curve is dependent on speed (rpm) divided by the square root of isentropic stage enthalpy drop. These curves exist for all three stages of the steam driven boiler feed pumps. The first stage has two curve sets: one for cold reheat steam nozzles and another set for main (primary) steam nozzles. There is even a curve for governor valve pressure drop.

The logic used to determine pressures and flows through each stage is as follows. The given parameter is auxiliary turbine second stage extraction pressure. This is determined by looking at main IP turbine exhaust pressure. Westinghouse balances use the same pressure for the auxiliary turbine second stage exhaust pressure. General Electric assumes a slight pressure drop in their balances. Using second stage flow and IP turbine exhaust pressure, the pressure ratio is obtained. Thus second stage inlet pressure (which is the first stage exhaust pressure) is determined. The third stage pressure ratio is determined by using second stage exhaust pressure and flow to the third stage.

Efficiency of each of the three stages will change with load as pump speed is changed. Turbine speed is the same as pump speed because the two machines are directly coupled. To determine pump speed, a characteristic bivariant capacity curve was installed. Boiler feed pump suction flow and discharge pressure determines pump rpm. The "X" variable was pump flow, the Y variable was discharge pressure and, the Z variable is pump rpm. Next the isentropic enthalpy drop square root is determined at the inlet to each stage. The pump rpm is divided by the square root drop and used to determine stage efficiency from the curve. The auxiliary turbine pressure ratios and stage efficiencies get entered into PEPSE.

Problems Encountered Using the Vendor Curves

Several curves for the auxiliary steam turbine did not match vendor heat balance diagrams. In some instances the curves and balances did not agree at all. We assumed the numbers on the balances were correct, unless their was a heat balance mistake. The IP turbine extraction was off by an estimated 10,000 lbm on one Westinghouse balance. For both vendors, efficiency curves were modified to match the efficiency shown on the balance. The flow function curve for the G.E. unit was not included in the auxiliary turbine thermal kit and was obtained from the vendor. Efficiency calculations were done every 5th iteration for optimum results at all load points. Unless done every 7th iteration pressure ratio calculations would not converge.

Primary Steam Use:

Main turbine throttle steam (or primary steam) usage depends upon maximum volume flow rate of cold reheat steam through the auxiliary turbine. At high loads maximum volume flow rate is exceeded through seven cold reheat governor valves and nozzle blocks. Additional supplemental steam is supplied by two primary steam valves and nozzle blocks. The maximum volumetric flow rate for cold reheat steam is calculated off the design heat balance diagram. This number is divided by the cold reheat specific volume. The answer is used for WWDMAX in the demand splitter supplying cold reheat steam to the auxiliary turbine. The splitter then signals the primary steam secondary source splitter.

Conclusions

The PEPSE turbine model simulating these units uses between 55 and 135 operating iterations to converge. This amounts to between 1.5 and 4 minutes on an IBM 3083 processor. The solution converges to the standard one lbm/1000 BTU convergence criteria. The model inaccuracy is less than one percent. This was accomplished by using effmults and shapers at all vendor load points. Effmults and shapers are fudge factors to adjust the expansion line curve to conform with actual real conditions. The effmult was especially necessary at the HP exhaust enthalphy. The models are sensitive to changes in HP turbine exhaust enthalpy. A few BTUs' change in enthalpy will cause the steam driven turbine to swing and become highly unstable.

The models still have minor short comings when only primary (main steam) steam is used. Primary steam flows through a different set of valves and nozzle blocks. There are a different set of pressure ratio and efficiency curves for primary steam. Accuracy is not affected when less than 10% primary steam is used in conjuction with cold reheat steam. It is a determining factor when more than 10% primary steam is used. In order to properly address this, two separate first stage sections are needed as shown in figure 4.

Having three high pressure heaters (the Will County model) above the deaerator, significantly improved model stability. Since the Will County Unit 4 model was finished first, it was assumed the same logic would work for the Joliet units. However, having two high pressure heaters instead of three heaters above the deaerator affected stability greatly. The Joliet model is less stable without the extra heater. The eight heater helped stabilize the auxiliary turbine as it slowly converged. A generic solution can not always be used for each application. Each different case must be treated separately.

Summary

Modeling extracting boiler feed turbines such as these using PEPSE is not an easy problem. The solution presented here is the results of three people: Mr. Scott Perry, Mr. David Ibrahim, and myself working on these models periodically over a time span of 3.5 years. Because of our efforts Commonwealth Edison Co. has working PEPSE models for extracting boiler feed pump turbines, that help predict, and test their performance.

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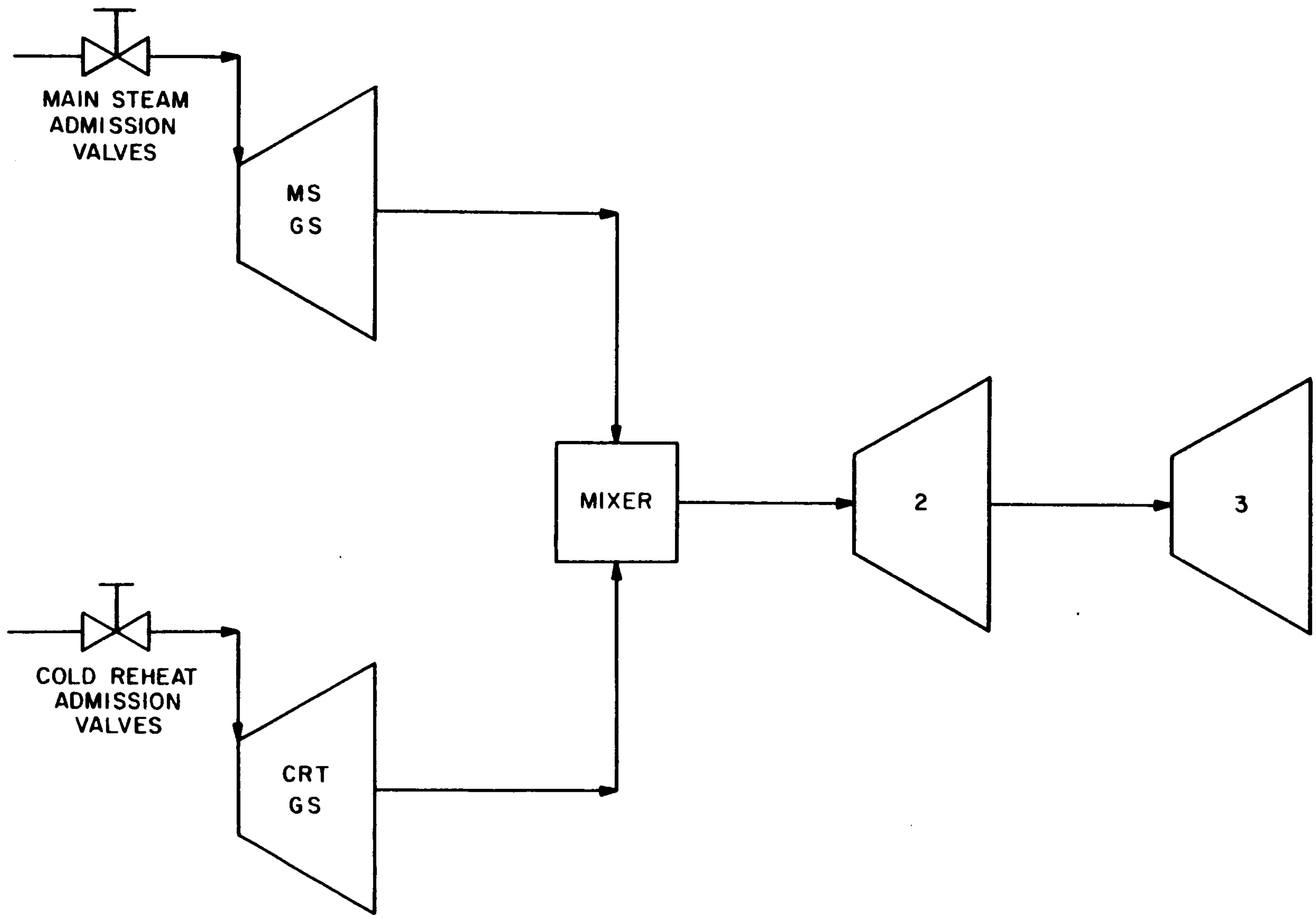

FIGURE 4: PROPOSED DUAL SUPPLY AUX. TURBINE CONFIGURATION