PEPSE® Analysis of Cogeneration Opportunities

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Introduction

Rochester Gas and Electric Corporation serves the upstate New York area, with corporate headquarters in Rochester, New York. Electric generation consists of a 500 MW nuclear plant, five (5) coal fired units with a total output of 350 MW, hydro-electric stations on the Genesee River with a total output of 50 MW, and two (2) 18 MW combustion turbines. RG&E is also a partner with neighboring utilities for 200 MW of oil fired generation and 150 MW of nuclear. RG&E and the other seven New York state utilities have been affected by independent power production in the state. The power from the Non Utility Generators is displacing power from our fossil fueled units, resulting in very low capacity factors. RG&E is pursuing customer partnering arrangements, in which RG&E would install a cogenerating facility on a customers site, to mutually benefit RG&E and the customer. PEPSE has been used to analyze the performance of cogeneration systems.

Background

The Public Utility Regulatory Policies Act was passed in 1978 as part of the National Energy Act. The intention of PURPA was to encourage efficient power production, especially in the area of cogeneration. PURPA removed utility and regulatory barriers to non-utility generation, and required utilities to purchase the electric output at a reasonable price. This price was determined by the state legislature, and in New York state this price was .06$/KWH. This applied only to "qualifying facilities", where at least 5% of the output of the plant was thermal energy, with the overall plant efficiency greater than 42%. The intent was that a local industry would become a thermal host, utilizing waste heat from an electric generating station. In New York state, however, the "6 cent rule" provided an opportunity for developers to sell electricity at a guaranteed price to the local utility, regardless of the need for that electricity. This has resulted in an excess of generation capacity in the state, and the utility's fossil generation units have been turned down as the NUGs come on line. There are many operating "PURPA plants" in New York state, where a developer found a thermal host and therefore could become a qualifying facility. The thermal energy can be provided at a very low cost to the host, because the plant will make sufficient income just from the electric sales. It is a good deal for the host and for the developer, but not for the utility or the utility's customers. The utility is forced to pay .06$/KWH for power that could be generated for about half that cost at a coal fired plant.

There are several examples of "PURPA plants" in our area. One is a 55 MW combined cycle plant that supplies steam to an industrial facility in Silver Springs, NY. The plant operates base loaded at 55 MW, and needs only to be certain that on an annual basis 5% of the plant output is supplied as steam to the industrial customer. This averages 30,000 lb/hour of steam flow, and the plant has an auxiliary boiler to provide this steam when the combustion turbine is out. All of the electric is sold to the local utility.

A much larger example is the Independence plant in Oswego, NY, which is scheduled to start up by year end. This is an 800 MW combined cycle plant, with 4 combustion turbines and 4 steam turbines. Approximately 400,000 lb/hour of steam will be supplied to the adjacent Alcan plant, and the 800 MW will be sold to Consolidated Edison and Niagara Mohawk.

Customer Partnering

The "6 cent rule" was written into contracts between the utilities and power producers, and will remain in effect for the 15 or 20 year contract period. The rule has now been changed, and new contracts require the utilities to purchase power at the rate determined by the Long Range Avoided Cost, which is 3 to 4 cents/KWH. Today it is generally not economical for customers to install a cogeneration facility with an electric output that exceeds the site demand, because the utility must only pay the LRAC rate for the excess power. However, if the utility owns and operates the cogeneration facility, the utility can oversize the unit and then dispatch the plant to meet utility system electric demands.

We have a program of Customer Partnering in which we work with major customers to identify any shared facilities that could benefit both RG&E and the customer. Many customers with large thermal loads are interested in cogeneration, and we have discussed placing a generation facility on the customers site that RG&E would own and operate. PEPSE has been used to prepare heat balances and analyze thermal output.

Example 1

A local college was considering a cogeneration plant to meet their energy needs. They currently have a central coal fired steam plant and an extensive campus steam distribution system. They also have a central chiller plant, with steam turbine drives on the centrifugal chillers. This results in a year round steam demand, with a winter peak of 150,000 lb/hour. They purchase all their electric from RG&E, with a peak demand of 20 MW. They were considering a 20 MW combustion turbine with a heat recovery steam generator. Example 1 shows a PEPSE schematic and heat balances for this application.

Example 2

A local manufacturing site requires 50 MW and 30,000 lb/hour of steam. Because the electric demand is high relative to the thermal requirement, they considered a combustion turbine in a combined cycle to maximize electric production. A cooling tower or air cooled heat exchanger were considered to condense the steam turbine exhaust. Example 2 shows PEPSE schematics and heat balances for these options.

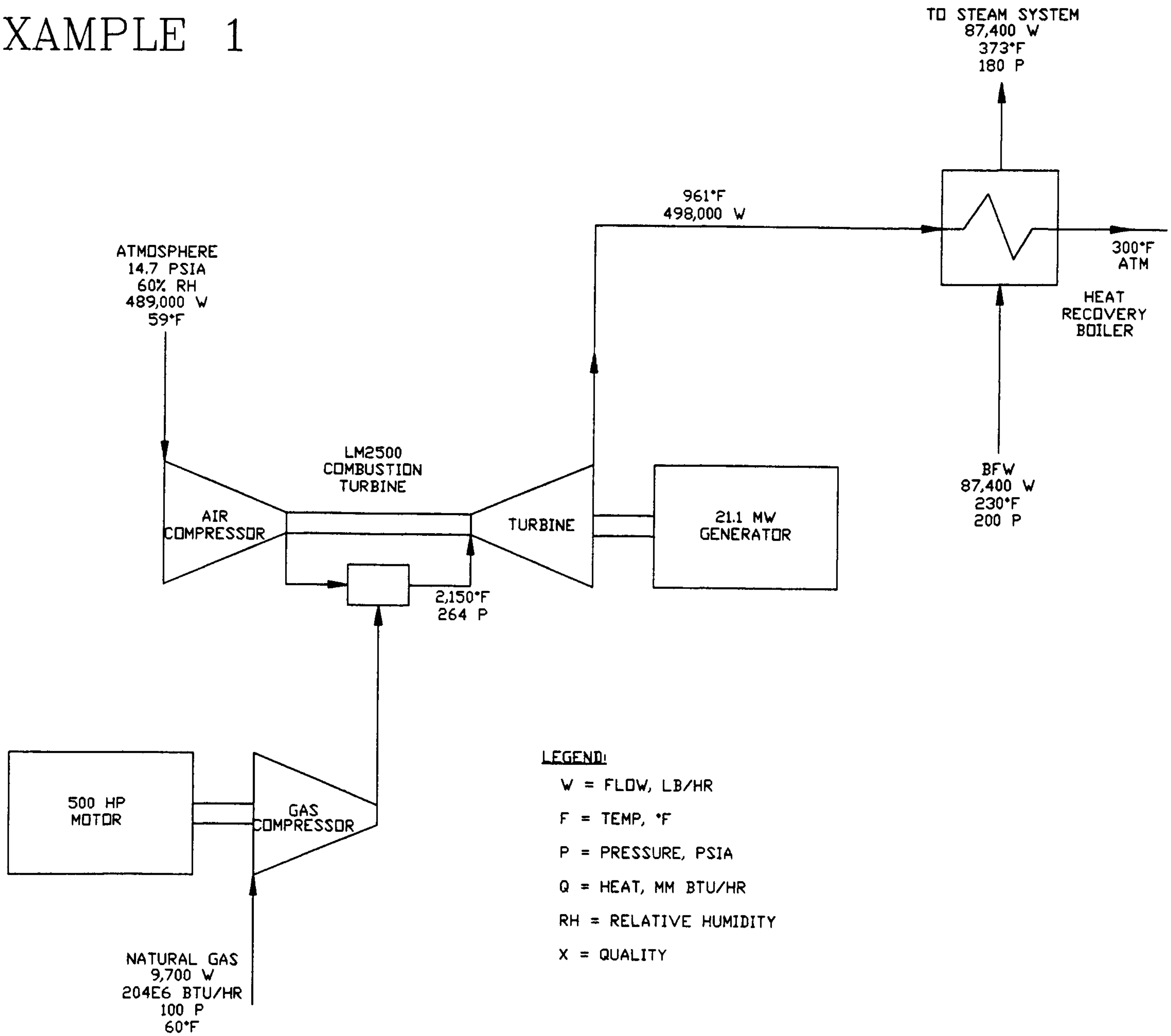
Example 3

A large manufacturing site has an extensive steam generation and distribution system. There are fifteen boilers on the site, ranging in size from 80,000 lb/hour to 550,000 lb/hour. The highest pressure boilers produce 1400 PSIG steam. The high pressure steam feeds back pressure turbines driving generators, and the exhaust steam is utilized in process applications. Many other mechanical drives utilize backpressure turbines to produce the lower pressure steam required. Total steam production capability from the boilers is 4 million lb/hour, with 200 MW of electric production. PEPSE was utilized to help evaluate the economics of steam turbine drives versus electric motors on process equipment.

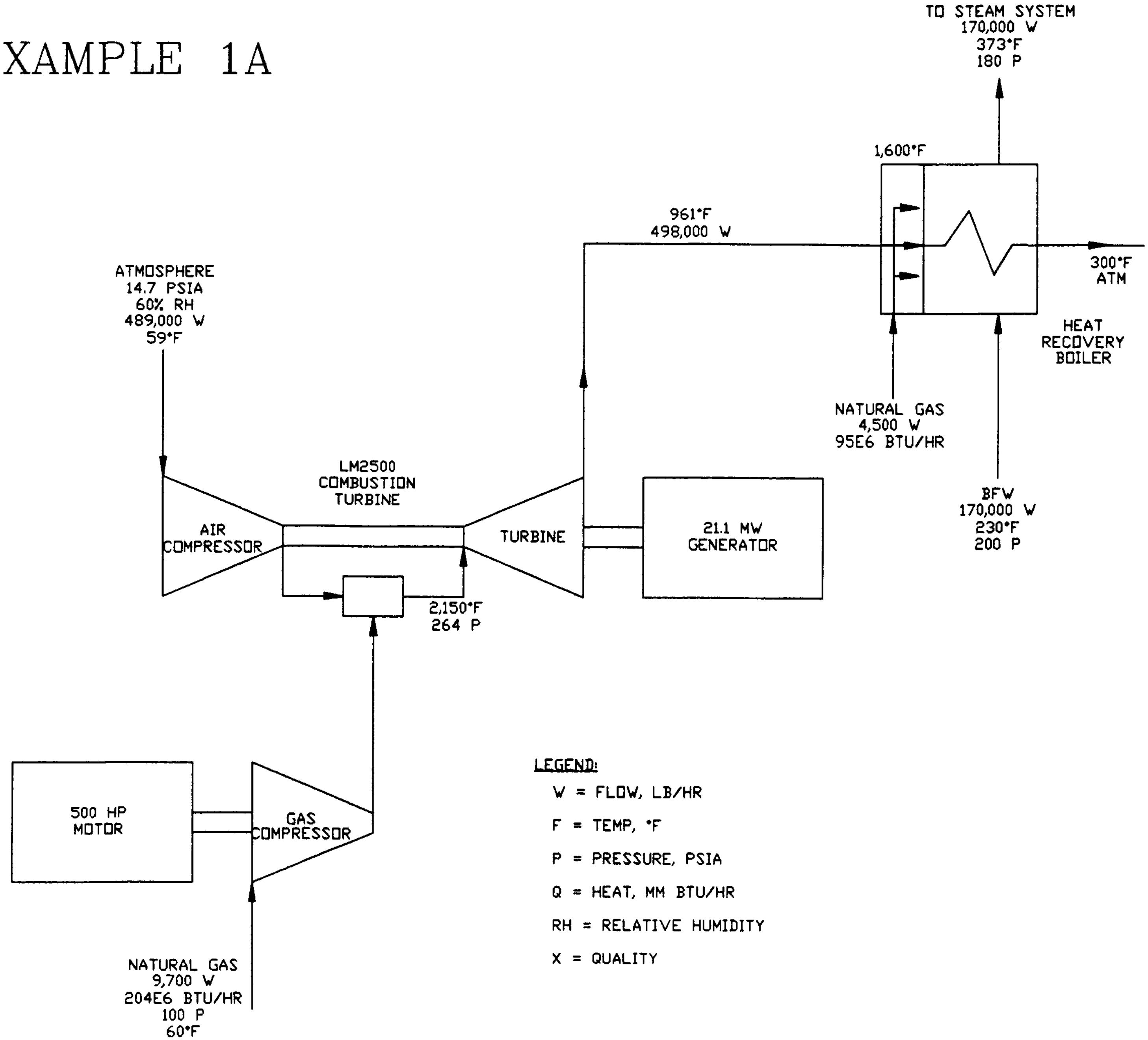
Conclusions

PEPSE is an effective tool that can help predict the performance of a wide range of process plant thermal systems. It has proven to be beneficial when used in screening studies, when firm vendor information is not available.

EXAMPLE 1


TO STEAM SYSTEM
87,400 W
373°F
180 P
961°F
498,000 W
300°F
ATM
HEAT
RECOVERY
BOILER
ATMOSPHERE
14.7 PSIA
60% RH
489,000 W
59°F
LM2500
COMBUSTION
TURBINE
AIR
COMPRESSOR
TURBINE
21.1 MW
GENERATOR
BFW
87,400 W
230°F
200 P
2,150°F
264 P
500 HP
MOTOR
GAS
COMPRESSOR
NATURAL GAS
9,700 W
204E6 BTU/HR
100 P
60°F
LEGEND:
W = FLOW, LB/HR
F = TEMP, °F
P = PRESSURE, PSIA
Q = HEAT, MM BTU/HR
RH = RELATIVE HUMIDITY
X = QUALITY
FILE: EX1

EXAMPLE 1A



TO STEAM SYSTEM
170,000 W
373°F
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961°F
498,000 W
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ATM
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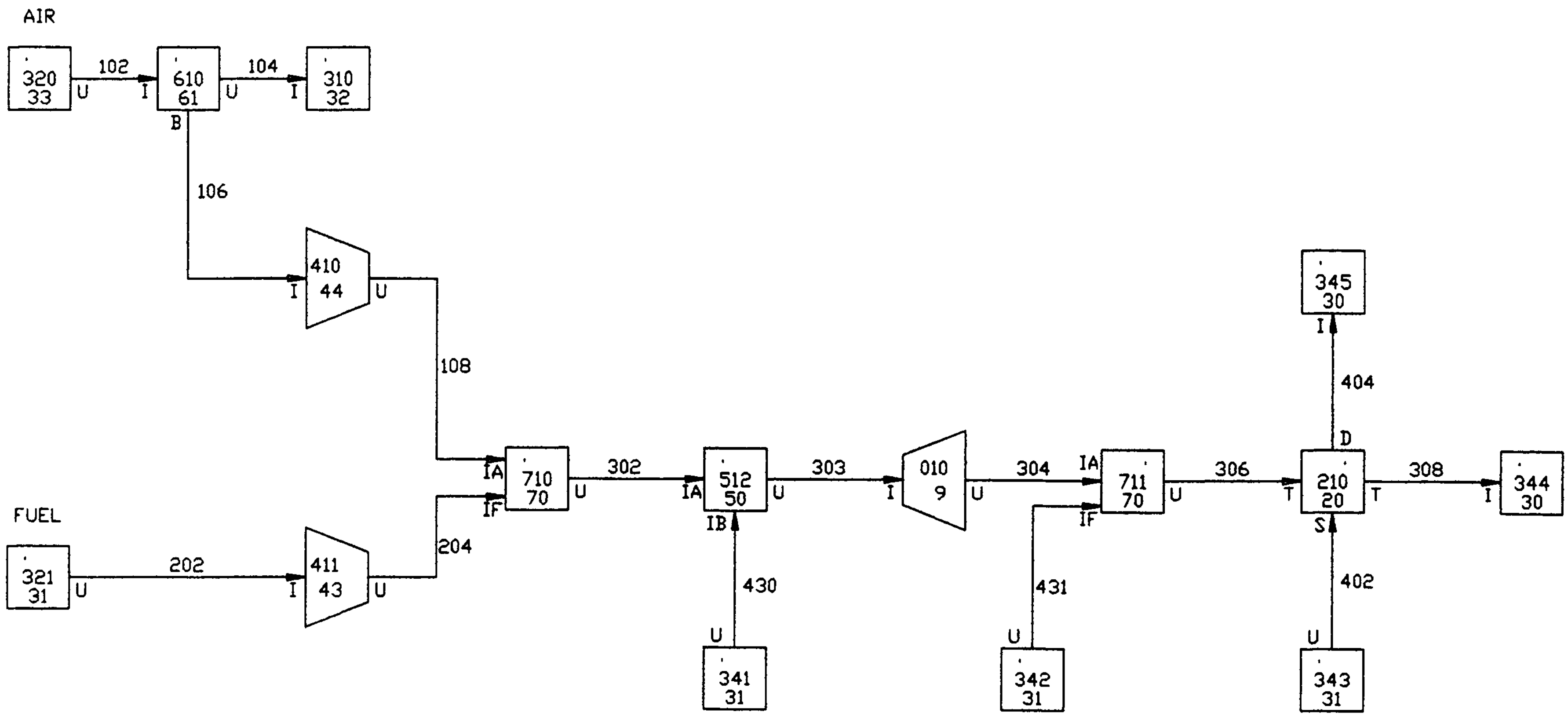
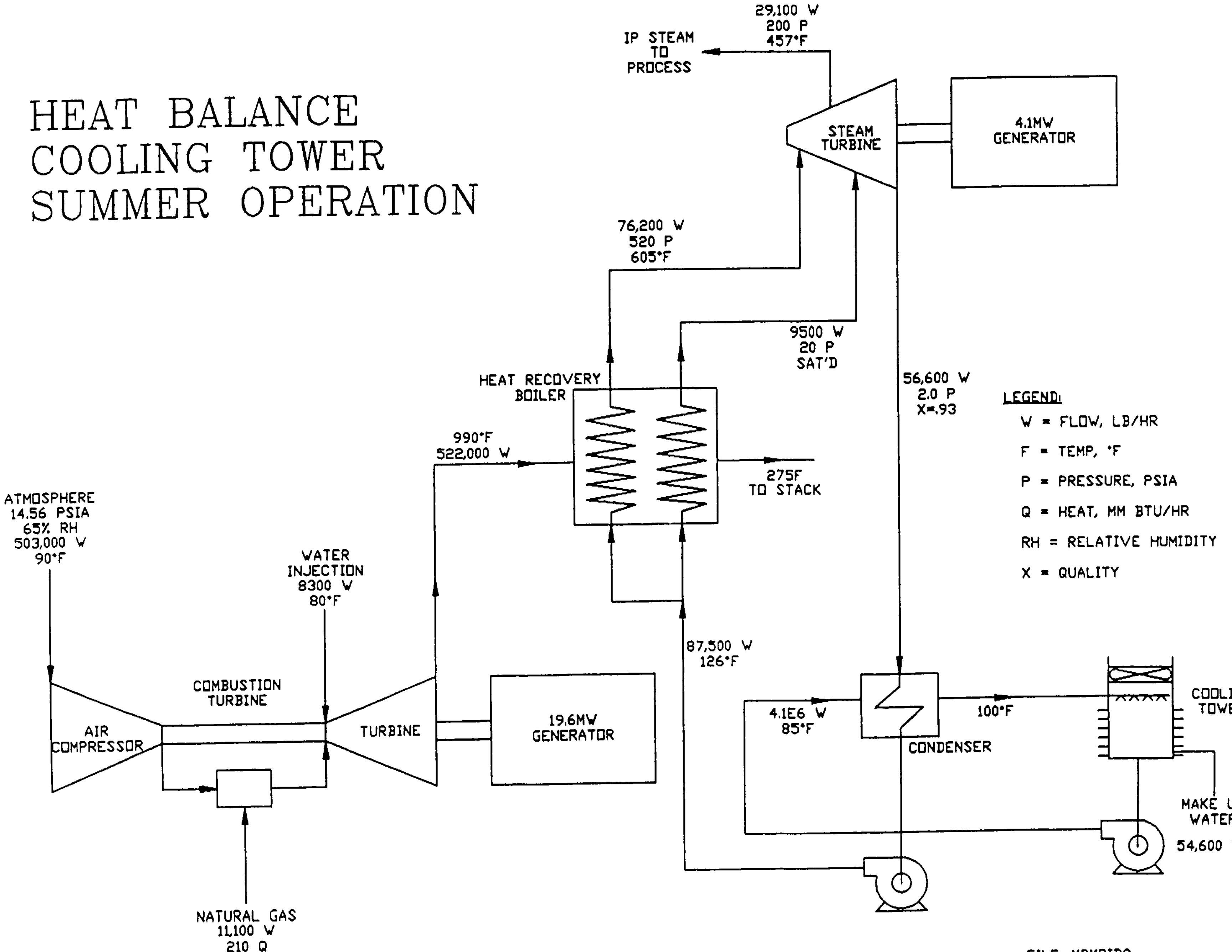
Q = HEAT, MM BTU/HR
RH = RELATIVE HUMIDITY
X = QUALITY
FILE: EX2



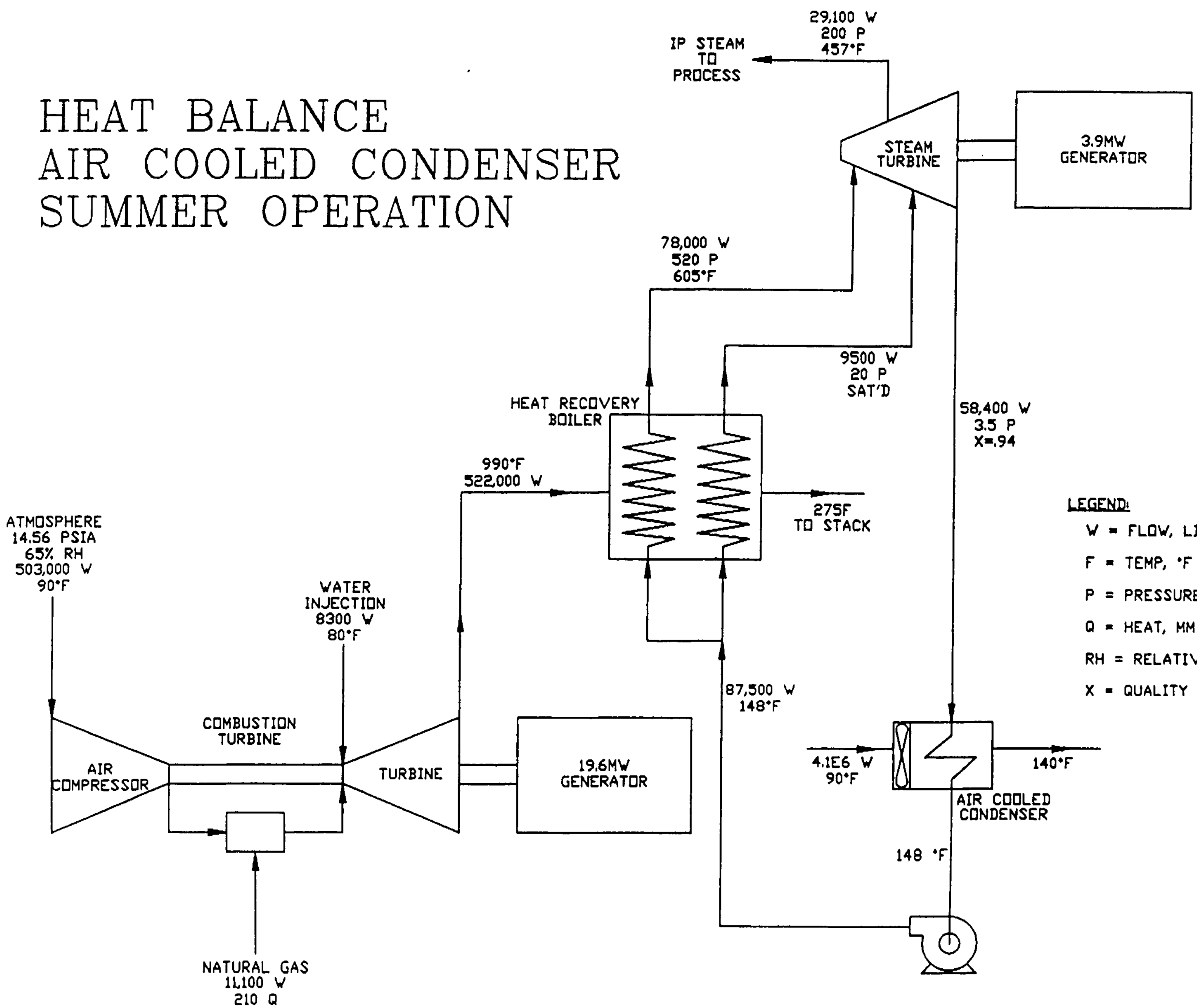
PEPSE SCHEMATIC
EXAMPLE 1B

FILE: EX3

HEAT BALANCE
COOLING TOWER
SUMMER OPERATION



HEAT BALANCE
AIR COOLED CONDENSER
SUMMER OPERATION



LEGEND:

W = FLOW, LB/HR

F = TEMP, °F

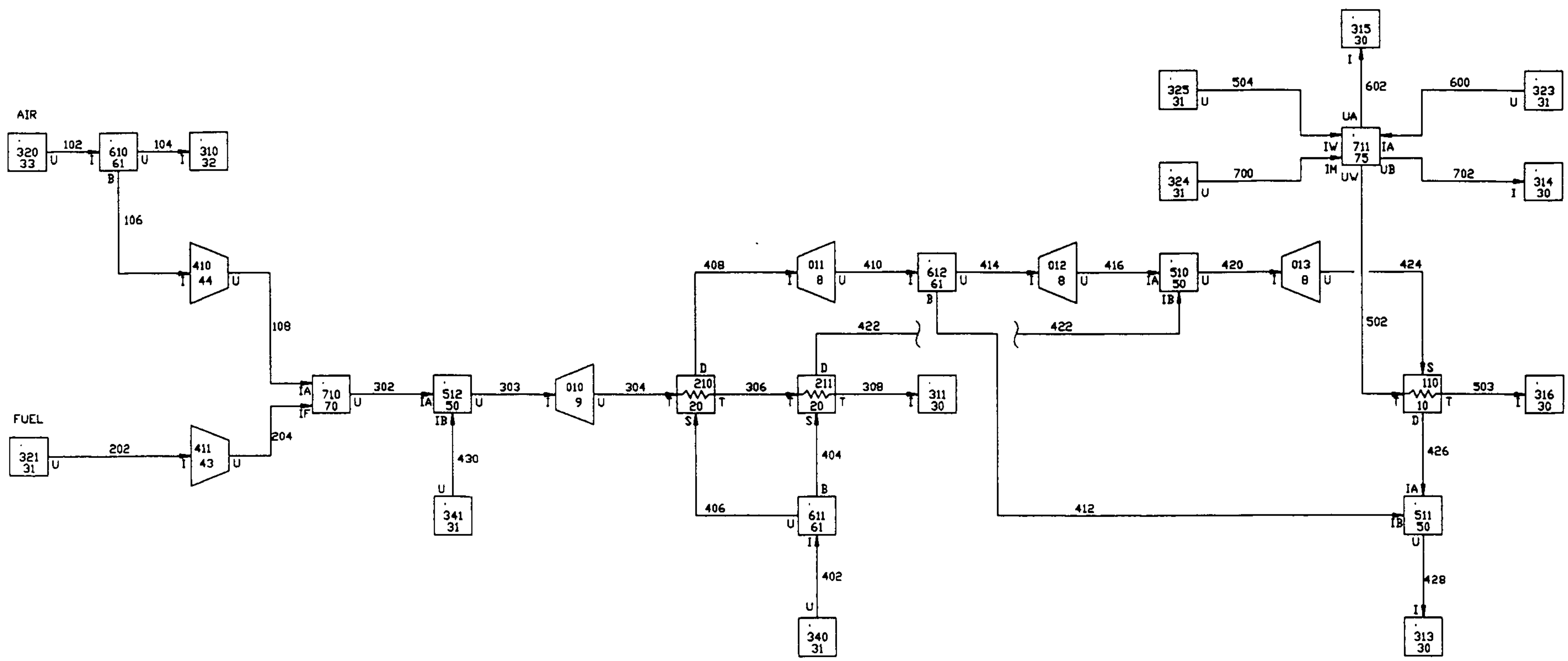
P = PRESSURE, PSIA

Q = HEAT, MM BTU/HR

RH = RELATIVE HUMIDITY

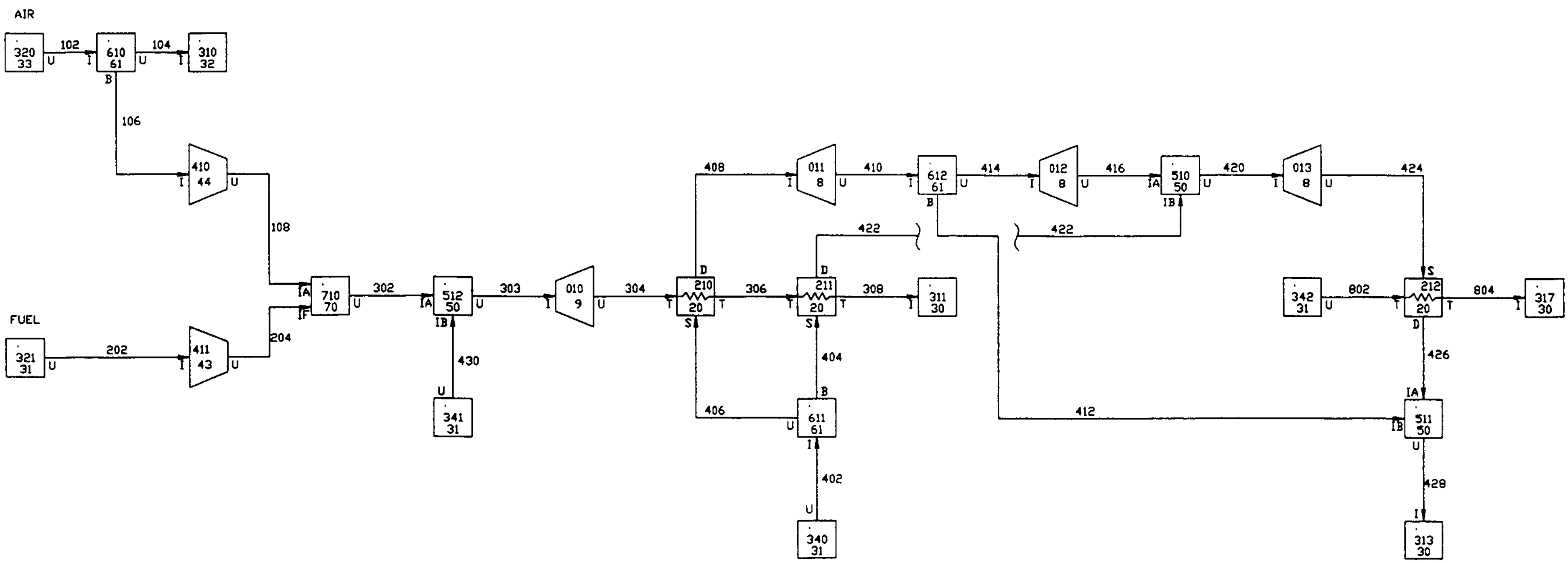
X = QUALITY

FILE: XRXPID7



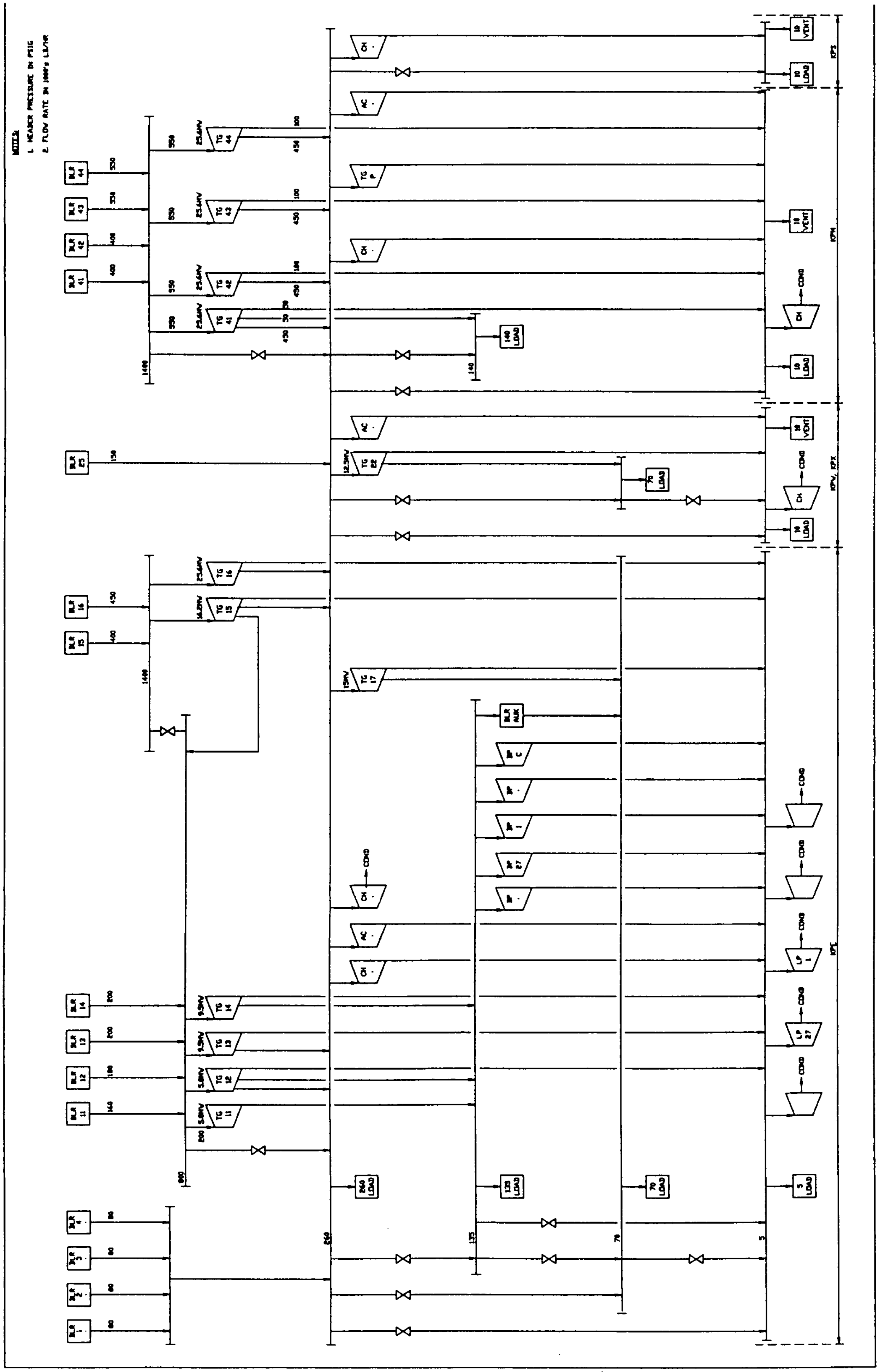
PEPSE SCHEMATIC
COGENERATION
COOLING TOWER

FILE: XRXPID4



PEPSE SCHEMATIC
COGENERATION
AIR COOLED CONDENSER

FILE: XRXPID3


NOTES:
1. HEADER PRESSURE IN PSIG
2. FLOW RATE IN 1000's LB/HR
BLR 44
BLR 43
BLR 42
BLR 41
BLR 23
BLR 16
BLR 15
BLR 14
BLR 13
BLR 12
BLR 11
BLR 4
BLR 3
BLR 2
BLR 1
TG 44
TG 43
TG 42
TG 41
TG 22
TG 16
TG 15
TG 17
TG 14
TG 13
TG 12
TG 11
BLR AUX
140 LOAD
70 LOAD
260 LOAD
135 LOAD
5 LOAD
VENT
COND
1400
800
260
135
70