EVALUATION OF COGENERATION AT OCCIDENTAL

INTRODUCTION

In today's phosphate industry with overcapacity in the United States and foreign competition growing, producers must continually seek methods for reducing production costs. Aside from raw materials, the largest contributors to variable costs are utilities (chiefly electricity). It also happens that electricity is one of the few major production costs that can be controlled to a significant degree. The method for that control is cogeneration, or on-site power generation. Although cogeneration can refer to power generated by fossil fuel produced steam, in the phosphate industry the steam is usually waste heat derived from the contact sulfuric acid process. The subject of this paper is cogeneration at Occidental Chemical's Suwannee River Chemical Complex. The content will chiefly attend to the feasibility study, evaluation, and economic justification of a cogeneration project, as it applies to Oxy.

FEASIBILITY

To ascertain the feasibility of a cogeneration project, the first step is the identification of the source(s) of steam on a quantitative basis (see fig. 1). As is the case of most phosphate producers, the steam producers are sulfuric acid plants. Next, the steam users must be identified. The steam users (see fig. 2) can be quite diverse and include processes both within and outside the sulfuric acid plants. The majority of users and generators will be variable as a function of production rate, product mix and efficiency.

A further key to proper evaluation involves analyzing the distribution of steam from a physical and pressure level stand point. "Physical" references to the sizing and configuration of the steam lines and valves (see fig. 3). This step is used later during quantitative steam balances, as the addition of a steam-turbine generator may result in significant changes in the distribution of steam within a system. These changes could result in pressure drops that impact system and turbine-generator performance. Peferring to pressures, it is necessary to identify system and turbine-generator operating pressures (see fig. 4). These pressures would be used later in conjunction with a steam balance to estimate the quantity of power produced from the turbine-generator.

To enhance the project's viability it is desirable to have the maximum available steam for the turbine-generator. Achieving this requires the identification of system modifications that will reduce heat losses, improve turbine efficiency, increase heat recovery or reduce usage (see fig. 5). Each of these projects, of course, must be justified on its own economic merits and technical risks.

EVALUATION

After this information is gathered, a steam balance must be developed. In the appendix, there is a sample calculation that illustrates a typical steam balance for a phosphate plant. Unfortunately, at any location that produces more than one product, a "typical" steam balance only tells a small fraction of the overall story. This is due to the strong variability of steam distribution as a function of production rate and product mix. A useful method for defining the trends of a system in terms of potential power generation as a function of product mix and production rate, is the use of "average liquid concentration" (see fig. 6). The method uses the weighted average of the concentration of all P_2O_5 liquids that are either shipped or used to make dry products. System trends can be closely approximated by developing steam balances at various production rates, for various product mixes from low P_2O_5% to high P_2O_5% combinations. The results may be expressed graphically (see fig. 7). This information is very versatile when preparing evaluations or requests for appropriation because it addresses all operating scenarios.

After completing the steam balances, it is necessary to calculate the electric power that could be produced utilizing the excess steam. This is illustrated in the sample calculation in the appendix. The information required for the calculation is: (see fig. 8)

- Steam Turbine Internal Efficiency
- Throttle Steam Conditions & Flow
- Extraction Steam Flow
- Flow as a Function of Maximum
- Generator Efficiency

Utilizing this information, power generated is calculated. By applying this to fig. 7, a similar representation of power vs. rate and product mix may be calculated (see fig. 9). Generated power represents the gross benefit of a cogeneration project, but there are factors that must be subtracted from this benefit. These factors are: (see fig. 10)

Maintenance Cost
Labor Cost
Electrical & Process Chemical Costs

Maintenance Costs for a cogeneration facility will be approximately 1% of the initial capital cost over the life of the project. (see fig. 11)

Labor costs will depend on location specifics. However, the power house should require only one operator per shift. (see fig. 12)

Electrical and process chemicals include those required to run powerhouse auxiliaries and maintain a cooling water treatment program. A typical turbine generator found in a phosphate complex would consume approximately: (see fig. 13).

1 MW YR Electricity	450,000 $	(@ $0.051/KWH)
	50,000 $	Water Treatment Costs
Total	500,000 $	/Yr.

JUSTIFICATION

When seeking an appropriation for a cogeneration project, it is necessary to total credits and costs. When attempting to estimate the cost benefits of generating electricity, several cost advantages exists. These are: (see fig. 14)

Energy Credit
Demand Credit
Peak Demand Credit

Energy credit represents the portion of a power bill that is related solely to the total KWH consumed. This quantity is determined by calculating the average power that will be generated and multiplying it by the energy cost. (see fig. 15)

Demand credit represents the portion of a power bill that relates to the highest amount of power drawn for a specified time during a billing period. Calculation of this quantity involves estimation of the reduction in power demand during each billing period and multiplication by the demand charge factor. (see fig. 16)

Peak demand credit is the credit that is possible to gain if the generation rate of the cogenerator is flexible. (see fig. 17) That is, on a day to day basis, the cogenerator must maximize power output during peak demand periods and therefore realize higher average revenues for the same KWH's generated. Calculation of this credit for appropriation purposes is difficult. However, on an individual basis the flexibility of a given installation may be estimated or applied to the appropriate peak demand charges. The term flexibility in this case refers to:

- Sulfuric Acid Capacity to Phosphoric Acid Capacity Ratio.

- Sulfuric Acid Storage to Sulfuric Acid Capacity Ratio.

Totalling all credits and operating costs, the annual benefits are determined. (see fig. 18) These are combined with a capital cost estimate of the installation (determined by factors outside the scope of this paper). The entire package is then turned over to financial analysis for economic evaluation.

EVALUATION OF COGENERATION

AT

OCCIDENTAL'S SUWANNEE RIVER

CHEMICAL COMPLEX

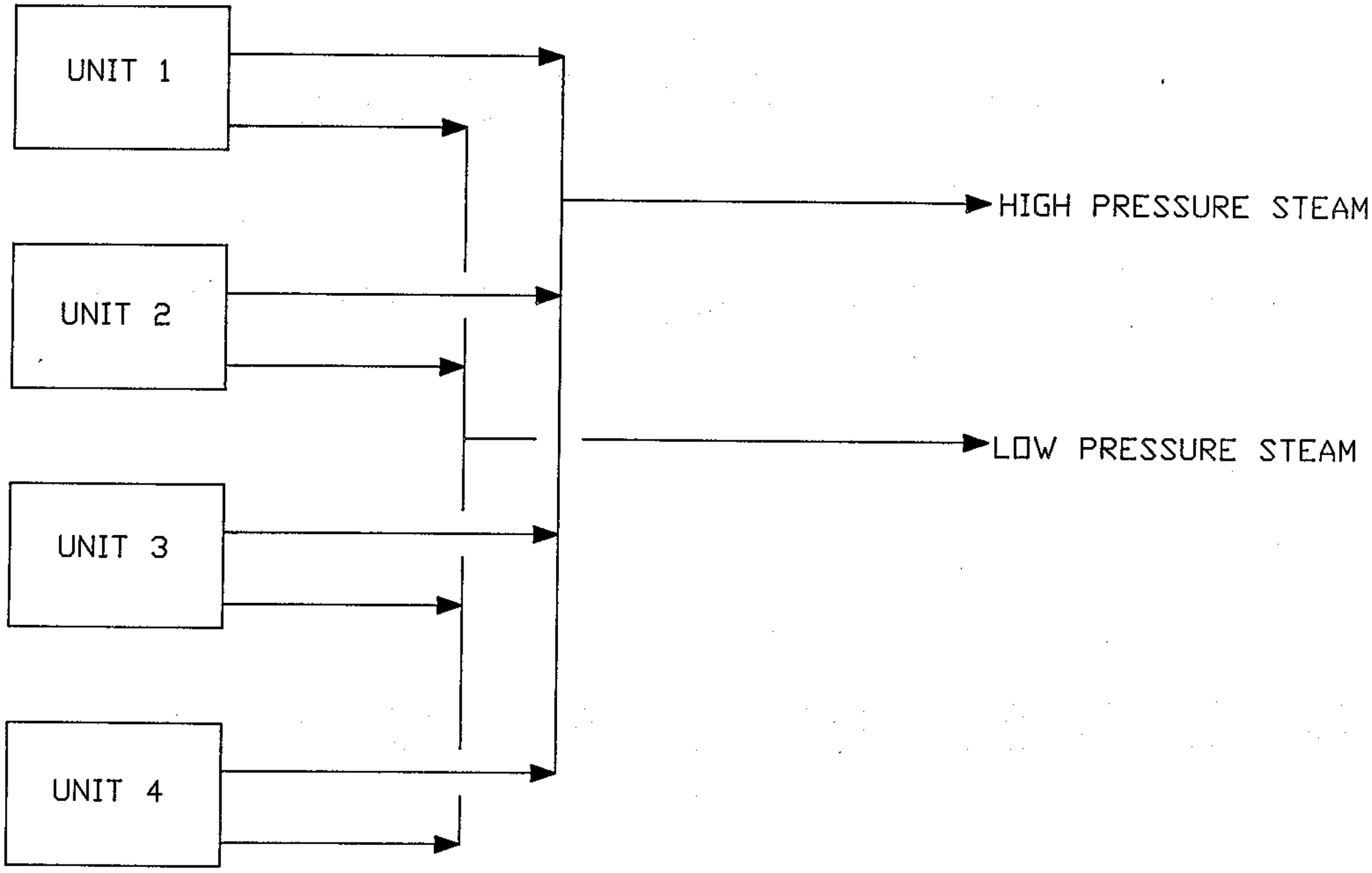
UNIT 1
UNIT 2
UNIT 3
UNIT 4
HIGH PRESSURE STEAM
LOW PRESSURE STEAM

FIGURE - 1

STEAM USERS

- * MAIN COMPRESSOR TURBINES (PRESSURE CHANGE)
- * SULFUR MELTING
- * BOILER FEEDWATER DEARATION
- * SMALL MECHANICAL DRIVE TURBINES (PRESSURE CHANGE)
- * LOW PRESSURE EVAPORATION

FIGURE - 2

* HIGH PRESSURE EVAPORATION
* STEAM EJECTORS
* FILTER WASH WATER HEATING
* TRACING
* LOSSES

FIGURE 2 (contd)

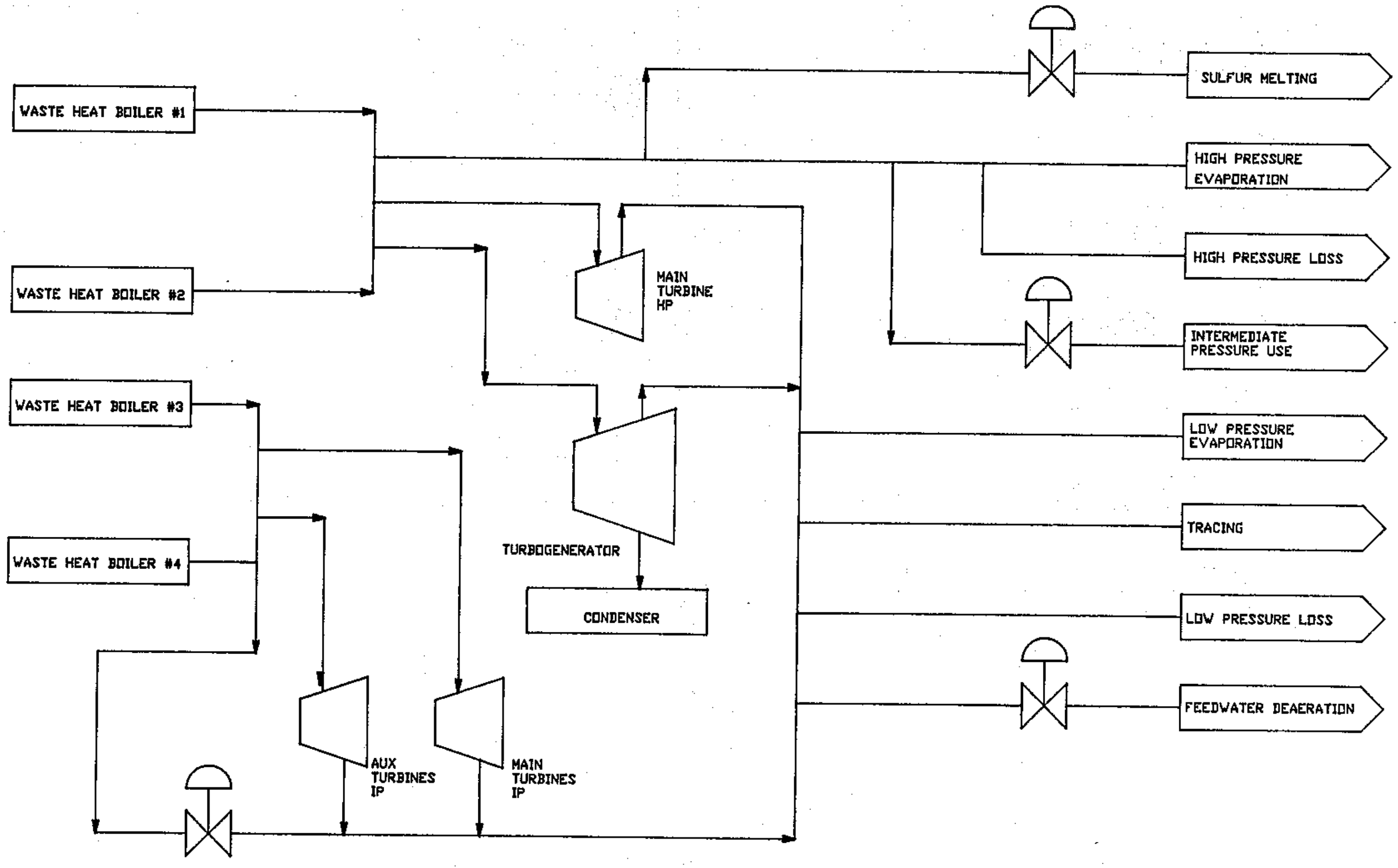
WASTE HEAT BOILER #1
WASTE HEAT BOILER #2
WASTE HEAT BOILER #3
WASTE HEAT BOILER #4
MAIN TURBINE HP
TURBOGENERATOR
CONDENSER
AUX TURBINES IP
MAIN TURBINES IP
SULFUR MELTING
HIGH PRESSURE EVAPORATION
HIGH PRESSURE LOSS
INTERMEDIATE PRESSURE USE
LOW PRESSURE EVAPORATION
TRACING
LOW PRESSURE LOSS
FEEDWATER DEAERATION

FIGURE - 3

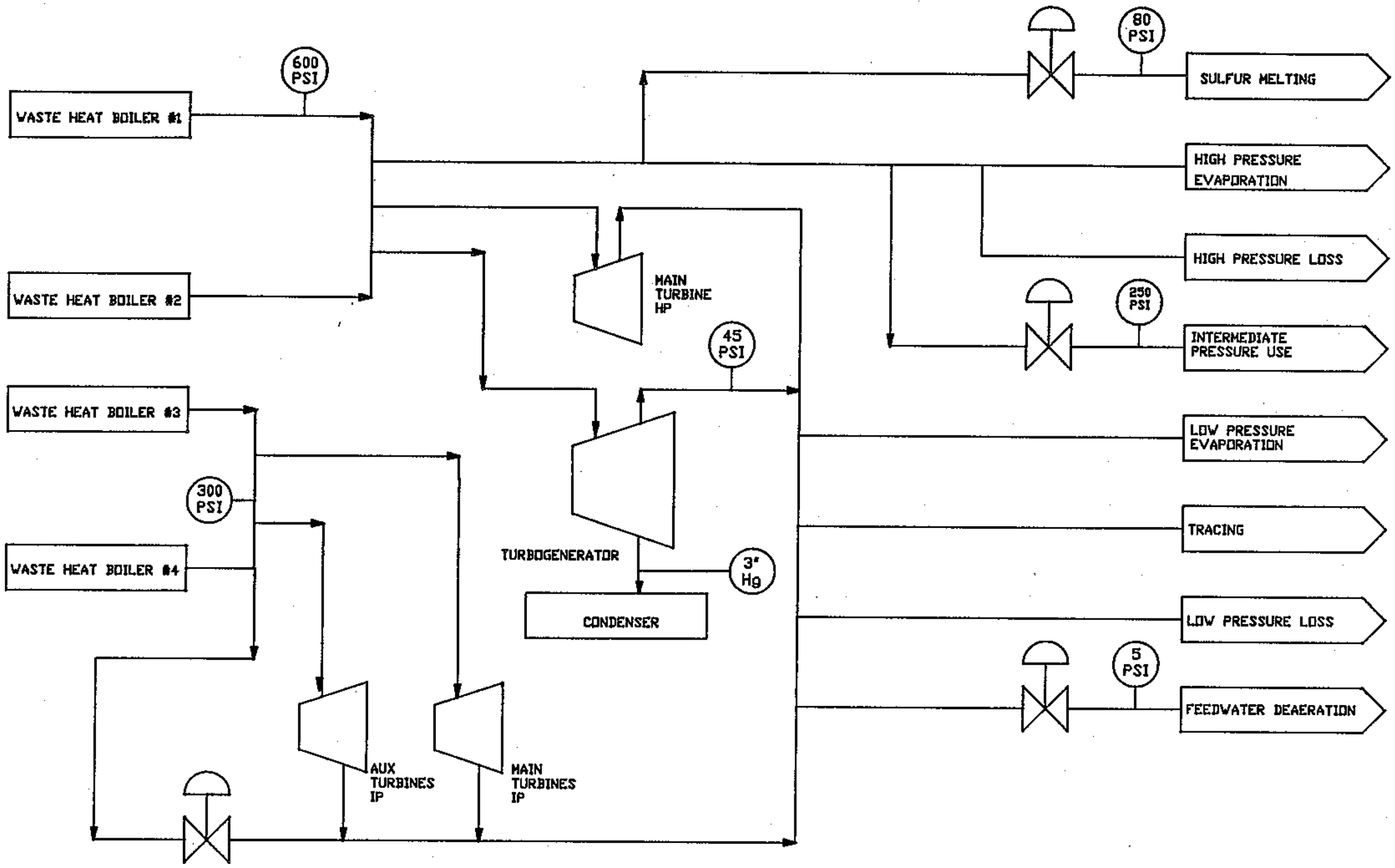
WASTE HEAT BOILER #1
600 PSI
WASTE HEAT BOILER #2
WASTE HEAT BOILER #3
300 PSI
WASTE HEAT BOILER #4
MAIN TURBINE HP
45 PSI
TURBOGENERATOR
3" Hg
CONDENSER
AUX TURBINES IP
MAIN TURBINES IP
80 PSI
SULFUR MELTING
HIGH PRESSURE EVAPORATION
HIGH PRESSURE LOSS
250 PSI
INTERMEDIATE PRESSURE USE
LOW PRESSURE EVAPORATION
TRACING
LOW PRESSURE LOSS
5 PSI
FEEDWATER DEAERATION

FIG - 4

SYSTEM IMPROVEMENTS

* LOWER TEMPERATURE ECONOMIZERS
* FEEDWATER PREHEATING
* SMALL TURBINE — MOTOR REPLACEMENT
* STEAM EJECTOR — VACUUM PUMP
  REPLACEMENT
* FILTER WASH WATER HEATING

FIGURE - 5

* MAXIMIZING FIRST FILTRATE CONCENTRATION

* INSULATING STEAM VALVES

* MINIMIZING BOILER BLOWDOWN

* MAXIMIZING TURBINE THROTTLE STEAM SUPERHEAT

FIGURE 5 (contd)

$$\text{AVERAGE P2O5 CONCENTRATION} = \frac{\left[\text{(CONC A)(TONS P2O5 A)} + \text{(CONC B)(TONS P2O5 B)} + \text{(CONC C)(TONS P2O5 C)}\right]}{\left[\text{(TONS P2O5 A)} + \text{(TONS P2O5 B)} + \text{(TONS P2O5 C)}\right]}$$

FIGURE - 6

FIGURE - 7

TYPICAL STEAM(HP) vs PRODUCT CONCENTRATION

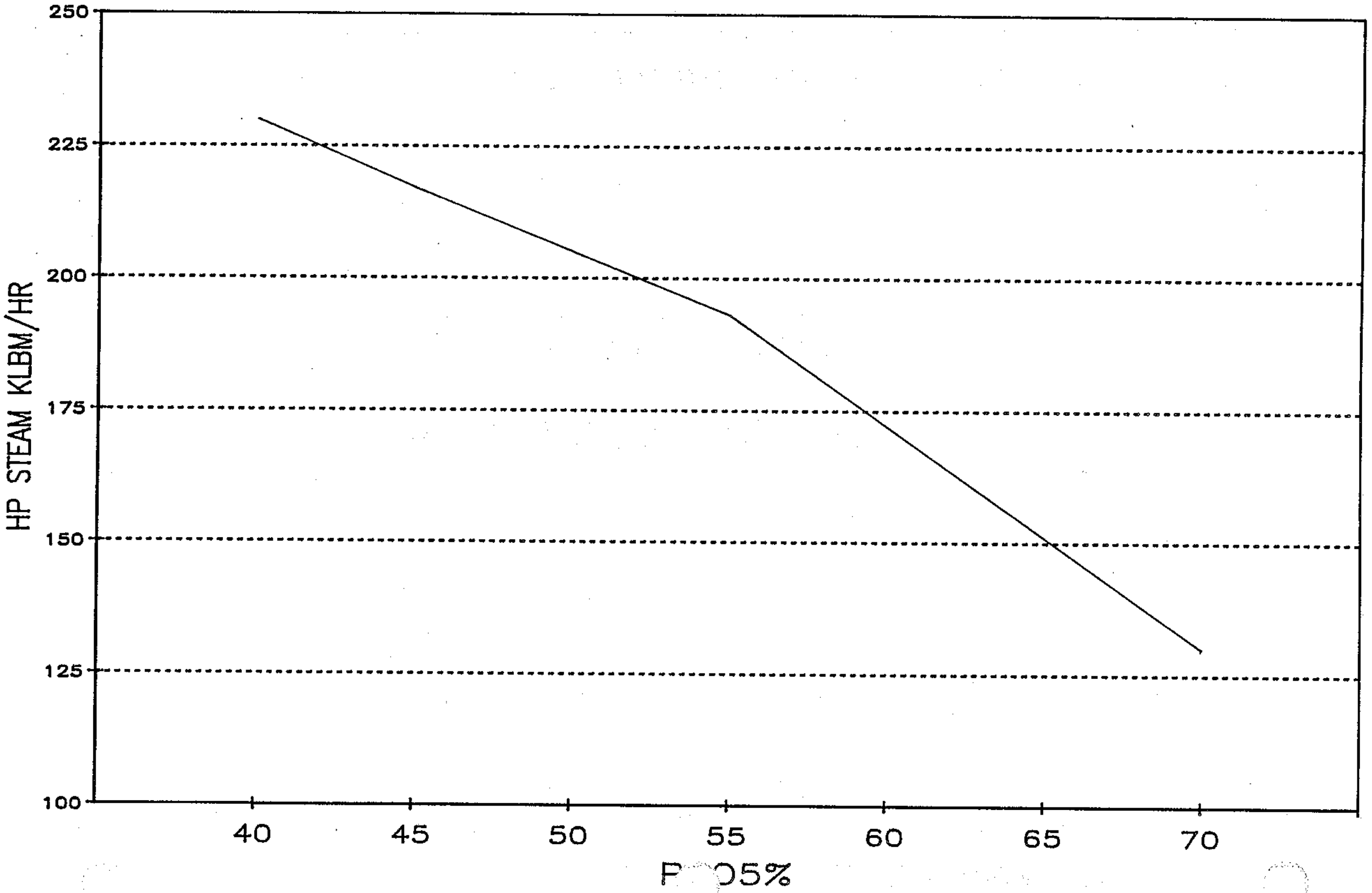

FIGURE - 8

FACTORS UTILIZED FOR CALCULATING POWER GENERATION

* MASS THROTTLE STEAM FLOW
* MASS EXHAUST STEAM FLOW
* EXTRACTION OR ADMISSION STEAM FLOW
* STEAM CONDITIONS
* TURBINE INTERNAL EFFICIENCY
* GENERATOR EFFICIENCY
* PARTIAL LOAD CORRECTIONS

FIGURE - 9

TYPICAL POWER VS PRODUCT CONCENTRATION

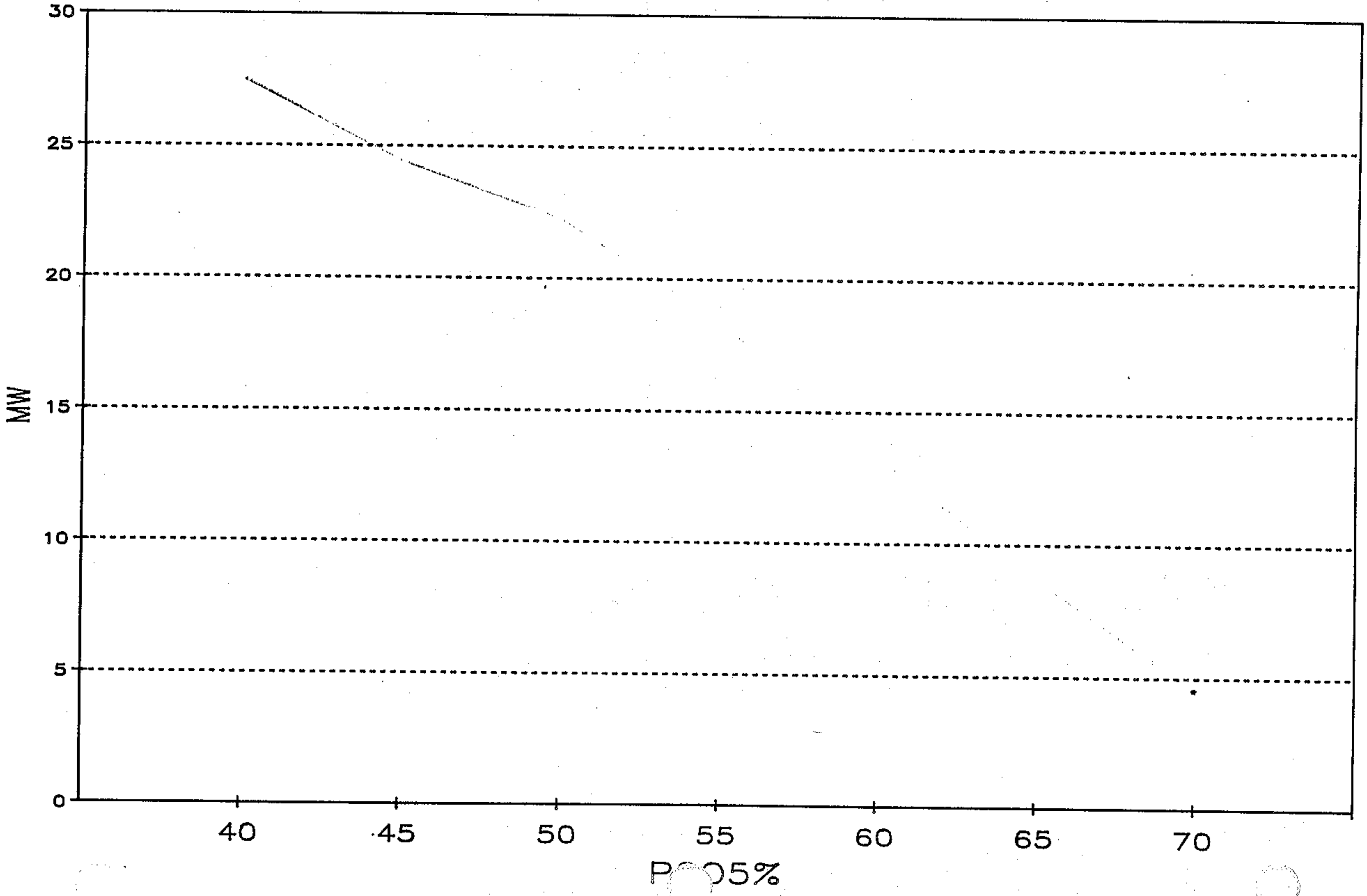

FIGURE - 10

MAINTENANCE COSTS

LABOR COSTS

ELECTRICAL & PROCESS

CHEMICAL COSTS

FIGURE - 11

MAINTENANCE COSTS

1% OF INITIAL CAPITAL COST

FIGURE - 12

LABOR COSTS

ONE (1) OPERATOR PER SHIFT

FIGURE - 13

ELECTRICAL & PROCESS COSTS

1 MW YEAR -- 450,000 $ (FLORIDA)

WATER TREATMENT -- 50,000 $

TOTAL -- 500,000 $/YR

FIGURE - 14

ENERGY CREDIT

DEMAND CREDIT

PEAK DEMAND CREDIT

FIGURE - 15

ENERGY CREDIT

=

(KW HR GENERATED)(COST/KW HR)

FIGURE - 16

DEMAND CREDIT

=

(REDUCTION IN DEMAND KW)(COST/KW)

FIGURE - 17

PEAK DEMAND CREDIT

FIGURE - 18

OPERATING CREDITS

— OPERATING COSTS

NET BENEFITS