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COMPUTER AIDED OPTIMAL DESIGN OF COMPRESSED AIR ENERGY STORAGE SYSTEMS

by

F.W. Ahrens, A. Sharma and K.M. Ragsdell

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Abstract

An automated procedure for the design of Compressed Air Energy Storage (CAES) systems is presented. The procedure relies upon modern nonlinear programming algorithms, decomposition theory and numerical models of the various system components. Two modern optimization methods are employed; BIAS, a Method of Multipliers code and OPT, a Generalized Reduced Gradient code. The procedure is demonstrated by the design of a CAES facility employing the Media, Illinois Galesville aquifer as the reservoir. The methods employed produced significant reduction in capital and operating cost, and in number of aquifer wells required.

Nomenclature

$A(d)$ = projected area of air bubble (Figure 3)

A_{act} = area of well-field (Figure 3)

BC = air bubble development cost

C = cost of electricity generated by CAES plant

CC = Cost of compressor train

C^* = minimum plant cost

C_1 = the part of C attributable to subsystem 1

C_2 = the part of C attributable to subsystem 2

C_1^0, C_2^0 = minimized cost functions for subsystems 1 and 2

C_{BAL} = cost of "balance-of-plant"

C_{CAP} = capital cost of subsystem 2

C_{HGT} = cost of high pressure turbine

C_{LGT} = cost of low pressure turbine

C_R = cost of recuperator

C_T = capital cost of subsystem 1

d = peak thickness of air bubble (Figure 3)

ε = recuperator effectiveness

H = mean thickness of bubble in well region (Figure 3)

K = constant or "temporary constant"

LC = land cost

$\dot{M}_c$ = air mass flow rate during storage

$\dot{m}'$ = (specific) air mass flow rate (per unit power generated)

N_w = number of wells (used as a continuous variable)

p_1 = inlet pressure to subsystem 2

$pd_{,min}$ = minimum pressure available from subsystem 1

P_c = compressor power

P_{GEN} = CAES plant power output

P_{REF} = power output of a reference turbine system whose cost is known

$\dot{Q}'$ = (specific) heat rate (per unit power generated)

r_{ec} = critical radius for well spacing

r_p = low pressure turbine pressure ratio

t_{cb_i} = beginning times for air compression (see Figure 1)

t_{ce_i} = ending times for air compression (see Figure 1)

T_3 = high pressure turbine inlet temperature

T_5 = low pressure turbine inlet temperature

U_L = utility load cycle (e.g. see Figure 1)

WC = well cost

$x_1, x_2 \ldots x_n$ = internal design variables for a subsystem

1. Introduction

Compressed Air Energy Storage (CAES) is a technique of storing large quantities of energy during off-peak consumption periods and of subsequent electric energy production to provide peaking capacity to electric utilities. An idealized diagram of an energy storage and generation cycle, arranged to meet the requirements of a typical utility grid, is shown in Figure 1. A typical CAES system schematic is given in Figure 2. The economic and engineering details of such systems have been previously discussed by many authors [1-7]. It is clear from these discussions that a large capital and technical investment would be required in CAES plants. There is also a lack of previous utility experience in design, construction and operation of CAES plants. Therefore, it is imperative that techniques of economically optimal and technically feasible design of CAES systems be developed.

The scale of technology involved in a CAES plant is of the same order of magnitude as that in any conventional power plant. Therefore, the only practical way of designing such a large system, without the benefit of previously developed standards, is to try to automate the design procedure. Any attempt at manual design would require a tremendous input of manpower and it would be difficult to guarantee a feasible much less an optimal design. The design approach presented in this paper succeeds in satisfying both these requirements.

Automated optimal design of a large engineering system presents a complicated problem with a large number of design variables and technical constraints. It is beneficial to decompose the problem into smaller subproblems. This reduces the size of individual problems to be handled and also allows different groups of experts to work within their areas of expertise. The reduction in the magnitude of the problem is significant since even the reduced subproblems require state-of-the-art optimization theory and computer programs. A further benefit of decomposition is that alternate subsystem designs can be explored more economically, since unmodified subsystems are not included in the computations. The CAES system decomposition used in this study is indicated in Figure 2.

This paper presents a comprehensive automated optimal feasible design procedure for CAES plants, including their interaction with the utility load cycle. The design approach is unified as opposed to other attempts at putting together separately designed components [5,6,8,9].

2. Optimization Methods

Space limitations will not allow us to examine in any reasonable detail the optimization methods employed. Since we anticipated difficulty in solving the subproblems, we used the best nonlinear programming methods at our convenient disposal. We attempted to use Fletcher's method of multipliers code [10] from the Harwell library, but did not meet with success because of the code's need for analytical gradients. If we had been successful in deriving correct analytical gradient expressions for the functions involved, certainly Fletcher's code would have performed in a manner similar to the other method of multipliers code used, BIAS [11]. BIAS is an implementation of the method of multipliers as developed by Root and Ragsdell [12] at Purdue. The code employs a scaling algorithm [13] which proved to be necessary in order to reach solutions. We did employ a Generalized Reduced Gradient, OPT, code [14,15] for the subproblem 2 optimizations and as a check on the BIAS results for subproblem 1.

The interested reader is referred to the cited references for the detail of these well known nonlinear programming methods.

3. CAES Problem Formulation

There are a large number of variables present in a CAES plant. The planning stage of design optimization involves selection of some of these variables as the decision (or design) variables. The remaining variables are then eliminated using various engineering relationships and system performance criteria. System decomposition is helpful at this stage as it reduces the conceptual size of individual subproblems to be solved, without compromising the final optimal design. However, the processes of decomposition and selection of design variables are interrelated and therefore iterative. The subsystem organization for the CAES problem was selected using physical intuition and by consideration of the ease of handling resulting design variables.

In broad terms, a CAES power system comprises the following: the air compression train (compressors, intercoolers, aftercoolers); compressed air piping; air storage reservoir (any type);

power generation train (e.g., turbines, combustors, recuperator); reversible motor/generator and the utility grid. Although the utility grid is not physically part of the CAES plant, this interaction should be considered in designing the plant, since the design (cost) of the plant can influence its utility usage (operating cycle). Conversely, the utility load cycle affects the plant design (i.e., a coupling exists). For the purpose of design optimization the overall system can be decomposed into three subsystems (see Figure 2). The first subsystem (subsystem 1) comprises the air compression train, the main piping and air distribution system and the air storage reservoir.

Subsystem 2 is the power generation train. The motor/generator and the utility grid are incorporated in the third group (subsystem 3). It is important to note that this particular decomposition is general, in the sense that it is not dependent upon the internal design of any particular subsystem. Furthermore, it minimizes the number of coupling variables. That is, the interactions of subsystems 1 and 2 with subsystem 3 are dependent on only one coupling "variable" -- the utility load cycle. The interactions between subsystems 1 and 2 (the ones of principle concern to the plant designer) are dependent on only three coupling variables -- the inlet pressure to the power generation train (p_1), the specific air mass flow rate ($\dot{m}'$) and the utility load cycle.

The criterion for optimum design is chosen to be the total normalized cost (C) of the system (i.e., cost per unit of electricity <u>generated</u> by the CAES power plant). This total cost is the sum of the individual costs.[†] The costs have to be minimized subject to various performance and technical constraints. The implication for CAES plant design is that, for a given utility load cycle, an optimization of subsystem 1 would provide the minimum subsystem operating cost (C_1^0) and values for the corresponding subsystem design variables, as a function of the coupling variables, p_1 and $\dot{m}'$. Similar optimization for subsystem 2 would yield C_2^0 (the minimum operating cost of subsystem 2) and its optimum design, as a function of the coupling variables only. Finally, the sum of C_1^0 and C_2^0 can be minimized to determine the optimum values of the coupling variables, the minimum plant cost (C*) and the optimal plant design. The process can obviously be expanded (in principle) to include variations in the utility load cycle and consideration of the resulting economic benefits or penalties to the utility. The remainder of this paper is confined to the design of a particular variety of subsystem 1 (one with an aquifer reservoir), to the design of subsystem 2, and to the synthesis of an optimal design for the CAES plant, using the subsystem 1 and 2 results.

3.1. Subsystem 1: Storage

An aquifer (originally water-filled) is an underground porous medium, which for storage should have the shape of an inverted saucer (see Figure 3) to prevent migration of the compressed air. The air bubble is formed by displacing the innate water; the compressed air is contained between the air tight caprock and a bottom layer of water. The operational constraints

[†] Typically the normalized operating costs include fuel costs, maintenance, charge rate on capital investment, etc.

for utilizing such a formation are discussed by Ahluwalia [16].

The compressor train included in this subsystem follows the recommendations of United Technologies Research Center [17]. To illustrate the procedure, a simplified piping and distribution system was adopted.

The following discussion briefly describes the technical modeling of subsystem 1. A detailed discussion of the model employed is given by Ahluwalia, et al [16], where an explanation of all the cost functions is also included. Here, we focus on the formulation of the optimal design problem.

In the optimization of subsystem 1, the objective is to determine the combination of internal design variables which minimizes the subsystem operating cost, for given values of the coupling variables, $p_1, \dot{m}'$ and U_L, where p_1 is the inlet pressure to subsystem 2 (Figure 2), and $\dot{m}'$ the specific mass flow rate. U_L is the power load cycle of subsystem 3, the utility power grid (Figure 1).

The set of design variables can be classified into two subsets. The first subset includes variables which are restricted to take a limited number of discrete values. Engineering considerations require that the main piping diameter, the type of low pressure compressor, and the reservoir wellbore diameters be restricted to discrete, economically available designs. As the number of alternates is limited, a simple method of incorporating these discrete variables in the optimization is an exhaustive search in all discrete dimensions.

Therefore, the following formulation assumes that the parameters resulting from the selection of a main piping system, low pressure compressor, and the well bore diameter are temporary "constants". The final step in optimization would be a search for minima in the parametric "constant" space.

The remaining internal variables of subsystem 1 are treated as continuous variables to be optimized, in a bound and constrained space. These variables are four geometric parameters of the reservoir design; N_W, H, A_{act}, and d, illustrated in Figure 3; and the energy storage process variables t_{cb_i} and t_{ce_i}. The variables t_{cb_i} represent the times during the weekly cycle when energy storage processes begin and t_{ce_i} are the ending times of these processes. The storage (charging) time variables are shown, for a typical cycle, in Figure 1.

The operating cost, to be minimized, can be written as

$$C_1 \; (N_W, H, A_{act}, d, t_{cb_i}, t_{ce_i})$$

$$= K_1(U_L)C_T + K_2(U_L)P_{c_i} \sum_i (t_{ce_i} - t_{cb_i}). \qquad (3.1)$$

In the equation above, K_1 and K_2 are functions of the coupling variable U_L, but are treated as constants for the purpose of optimization. Similar notation is used to represent functions of other coupling variables and functions of the three discrete internal variables. Absolute constants appear in the following without any functional dependence shown. However, for the purpose of the optimization problem statement, all K's can be treated as constants. The first term in equation (3.1) represents the operating cost due to the annual charge rate on the capital, C_T, of subsystem 1, where C_T is the sum of capital costs of components,

$$C_T(N_w, H, A_{act}, d, t_{cb_i}, t_{ce_i})$$

$$=WC + LC + BC + CC + K_3(\text{piping}) \tag{3.2}$$

K_3(piping) is the capital cost of the main piping and distribution system which depends upon the piping design selected. The capital cost of wells is:

$$WC(N_w, H, A_{act}) = N_w[K_{w_1} + K_{w_2} \{H - F(A_{act})\}] \tag{3.3}$$

with constants K_{w_1}, K_{w_2}, and $F(A_{act})$, a known function of A_{act} determined from reservoir geometry. The term within curly brackets in equation (3.3) is the depth to which wells have to be bored. The second term in equation (3.2) is the cost of purchasing the land over the proposed reservoir;

$$LC(d) = K_\ell A(d). \tag{3.4}$$

A(d) is the land area over the air reservoir, a known geometric function of d.

In this simplified model, the capital cost of initially displacing water from the aquifer, or bubble development, is calculated in terms of energy required to compress the volume of air in the bubble, as

$$BC(d) = K_b V(d) \tag{3.5}$$

where V(d) is the volume of air bubble, which is a function of d.

Finally, the capital cost of the compressor train is required and is expressed as:

$$CC(N_w, H, A_{act}, d, t_{cb_i}, t_{ce_i})$$

$$= K_{c\ell_1} + K_{c\ell_2}\dot{M}_c + K_{cb_1}\left[\dot{M}_c\{\frac{p_c}{K_{c\ell_3}} - 1\}\right]^{K_{cb_2}} \qquad (3.6)$$

Here $K_{c\ell_1}$, $K_{c\ell_2}$, and $K_{c\ell_3}$ are parametric constants determined by the choice of compressor train design, $\dot{M}_c$ is the air mass flow rate during the storage processes, chosen to be the same during all storage processes due to compressor performance considerations.

$$\dot{M}_c = \frac{K_M(U_L, \dot{m}')}{\sum_i (t_{ce_i} - t_{cb_i})} \qquad (3.7)$$

K_M is another "constant" determined by the coupling variables U_L and $\dot{m}'$. The remaining unknown term in equation (3.6) is p_c, the discharge pressure required of the compressor train. This pressure can be calculated using the pressure drop models given by Sharma [1].

The second term in equation (3.1) is the subsystem operating cost incurred due to compressor power consumption, P_c, which is given by

$$P_c(N_w, H, A_{act}, d, t_{cb_i}, t_{ce_i})$$

$$= [K_{P_1} + K_{P_2} p_c + K_{P_3}p_c^2 + K_{P_4}p_c^3]\dot{M}_c. \qquad (3.8)$$

The functional dependences of the objective function are summarized in the subproblem graph of Figure 4.

Engineering intuition, aquifer geology and geometry, and the utility load cycle U_L specify bounds on the design variables. The design space to be searched for optima is, however, specific to the example considered in section 4.

$$\begin{aligned} &1 \le N_w \le 1500 \\ &0 \le H \le 105 \text{ ft.} \\ &0 \le A_{act} \le 1.3 \times 10^9 \text{ ft}^2 \\ &0 \le d \le 115 \text{ ft.} \\ &t_{cb0_i} \le t_{cb_i} \le t_{ce0_i} \\ &t_{cb0_i} \le t_{ce_i} \le t_{ce0_i} \end{aligned} \tag{3.9}$$

where t_{cb0_i} and t_{ce0_i} are the bounds on storage process times specified in the utility load cycle, as shown in Figure 1.

As mentioned earlier, various performance requirements, subsystem interactions and other criteria limit the design space; thus requiring a constrained optimization. For the case being considered, a number of additional constraints are appropriate. The first set of constraints,

$$t_{ce_i} - t_{cb_i} \ge 0 \tag{3.10.1}$$

state that a storage process must end after it begins. The second constraint requires that the well spacing should be close enough to ensure full utilization of the reservoir volume,

$$\pi r_{ec}^2 N_w - A_{act} \ge 0 \tag{3.10.2}$$

where r_{ec} is the "critical" radius discussed by Ahluwalia, [16]. Furthermore, the following constraints derive from the air reservoir geometry:

$$A_{act} - 4r_w^2 N_w \geq 0 \tag{3.10.3}$$

states the requirement that well bores should not interfere,

$$A(d) - A_{act} \geq 0 \tag{3.10.4}$$

requires the area over the "bubble" be the maximum area available for well sinking. The next constraint,

$$d - K_{dc} - H + F(A_{act}) \geq 0 \tag{3.10.5}$$

prevents the well bores from extending to a depth that might cause water coning, and

$$K_U(U_L) - P_c \geq 0 \tag{3.10.6}$$

limits the compressor power P_c to that available from the utility. Finally we impose:

$$P_{d,min}^2 - P_1^2 \geq 0. \tag{3.10.7}$$

$P_{d,min}$ is the minimum pressure available from subsystem 1. This last constraint involves the coupling variable p_1 and ensures that the pressure requirements of subsystem 2 are met at all times during the weekly cycle.

Note that constraints (3.10.4) through (3.10.7) are non-linear. Also the calculation of $p_{d,min}^2$ for the last constraint uses the pressure drop models in a manner similar to the calculation of p_c [1].

We now have a complete definition of the optimization problem for subsystem 1. Application of a nonlinear programming algorithm to this problem provides optimum values for all the internal variables which correspond to the least value of the subsystem cost function $C_1^0\ (U_L;\ p_1,\ \dot{m}')$.

3.2 Subsystem 2: Generation

Subsystem 2 of the CAES system comprises the high and low pressure turbines, their combustors and the recuperator, as indicated in Figure 2. It is also considered to include the balance-of-plant (assumed not be variable). The most interesting design tradeoffs for this subsystem are: (a) larger, more effective recuperator vs. greater premium fuel consumption in the combustors, for preheating the air entering the turbines, and (b) advanced, high inlet temperature turbines, having high cost but high performance vs. conventional, lower temperature, lower cost turbines. An additional tradeoff, of secondary importance, is the pressure ratio split between the high-pressure turbine and the low-pressure turbine.

The performance model for subsystem 2 is based on a thermodynamic analysis (i.e., mass and energy balance equations) of the components. The detailed equations are given by Kim [18,19]. It should be mentioned, however, that the model includes the effect that as the turbine inlet temperatures are increased above a certain threshold value (taken to be 1600°F), it is necessary to use an increasing fraction of the compressed air from storage to provide cooling for the turbine blades and other turbine components.

For the purpose of calculating the subsystem 2 performance, the coupling variables, p_1 (the subsystem inlet pressure) and $\dot{m}'$ (the specific turbine system air flow rate, lb_m/kWh), and P_{gen}, the total power output from the two turbines, are regarded as inputs. Because of this, it is not possible to independently specify both turbine inlet temperatures, T_3 and T_5, if fixed, state-of-the-art, turbine efficiencies are assumed. In the present model, T_5 (low-pressure turbine inlet temperature) was considered as a design variable and T_3, along with several intermediate variables, was subsequently determined during the iterative solution of the model equations. The other design variables of subsystem 2 are the recuperator effectiveness, ε, and the low-pressure turbine pressure ratio, $r_p (= p_5/p_6)$. The variable r_p was considered to be discrete. Its two values (11 and 16) correspond to the current practice of turbomachinery manufacturers.

With specified values of the design variables, others operating conditions and performance characteristics are predicted from the solution of the model equations. Of particular note is the specific heat rate, $\dot{Q}'$ (Btu/kWh), which is proportional to the rate of premium fuel consumption of the CAES plant.

In the optimization of subsystem 2, the objective is to find the combination of internal design variables which minimizes the subsystem operating cost, for given values of the coupling variables. During a particular optimization process, the coupling variables, p_1 and $\dot{m}'$, and U_L, are fixed, and so will be omitted from the functional relationships which follow. The discrete variable r_p is also omitted, since an optimization is performed separately for each of its values.

The operating cost to be minimized can be written as:

$$C_1 \ (T_5,\varepsilon) = K_1(U_L)C_{cap} + K_F\dot{Q}' + K_{om} \tag{3.11}$$

The first term represents the operating cost due to the annual charge rate on the capital, C_{cap}, of subsystem 2, where C_{cap} is the sum of capital costs:

$$C_{cap} \ (T_5,\varepsilon) = C_{LGT} + C_{HGT} + C_R + C_{BAL} \tag{3.12}$$

The capital cost components indicated are as follows. First, the cost of the low pressure turbine is:

$$C_{LGT} \ (T_5) = \frac{P_{GEN} \ (U_L)}{P_{REF}} C_L(T_5) \tag{3.13}$$

where $C_L(T_5)$ is the cost of the low pressure turbine for a reference turbine system of power output, P_{REF}. It is an increasing function of T_5, reflecting the added complexity of providing for cooling air when high inlet temperatures are used. $C_L(T_5)$ is based on a curve fit of data given by Davison [17]. $P_{GEN} \ (U_L)$ is the CAES plant power output required by the utility load cycle (U_L).

Similarly, the cost of the high pressure turbine is:

$$C_{HGT}(T_5,\varepsilon) = \frac{P_{GEN} \ (U_L)}{P_{REF}} C_H \ (T_3(T_5,\varepsilon;p_1,\dot{m}'); \ p_3) \tag{3.14}$$

The cost (C_H) of the reference high pressure turbine increases with both its inlet temperature (T_3) and inlet pressure (p_3). The latter is taken to be 9% lower than p_1, due to pressure losses. The cost function is based on a curve fit of data given by Davison [17].

The cost of the recuperator is modeled by the relation:

$$C_R(\varepsilon) = K_R(U_L,\dot{m}') \frac{1}{(\frac{1}{\varepsilon} - 1)} \qquad (3.15)$$

The balance-of-plant (switchgear, buildings, etc.) is assumed proportional to power generation level:

$$C_{BAL} = K_{BAL}\ P_{GEN}\ (U_L) \qquad (3.16)$$

K_{BAL} is taken to be \$70/kw.

The constant $K_1(U_L)$ in equation 3.11 converts capital cost to an equivalent operating cost (mills/kWh) and includes several factors such as capital charge rate, contingencies, engineering and administration, etc. Data used for these factors is the same as employed by Kim [19,20]. A yearly operating time of 2500 hours at full power is assumed.

The second term in equation 3.11 is the cost of the premium fuel used in the combustors. K_F is taken as \$2.50/10^6 Btu. The heat rate, $\dot{Q}'$, is dependent on $T_3(T_5,\varepsilon)$ and T_5. The final term in equation 3.11 is the operating and maintenance cost of the plant. It is considered to have a constant value, 2 mills/kWh.

When the subsystem model was used in optimal design studies the following vairable bounds and design constraint were specified:

$$0 \leq \varepsilon \leq 1 \qquad (3.17)$$

$$1500 \leq T_5 \leq 2400 \text{ F} \qquad (3.18)$$

$$1500 \leq T_3(T_5,\varepsilon) \leq 2400 \text{ F} \qquad (3.19)$$

The first of these simply represents the physically possible range for a heat exchanger effectiveness. The second and third correspond to the range of turbine inlet temperatures considered to be of practical interest, and for which cost data were available.

To aid in obtaining accurate predictions of optima, it was found advantageous to define a scaled temperature variable, $T_5' = T_5/1000$. This causes ε and T_5' to be of the same order of magnitude, which is desirable when employing an optimization code without an automated scaling procedure.

When a nonlinear programming algorithm is applied to the subsystem 2 problem, the optimum values for its internal variables are found. These correspond to the minimum cost function, $C_2^0\ (U_L;\ p_1,\ \dot{m}')$.

4. Numerical Results

To illustrate the application and to determine the implications of the CAES plant design problem formulation which has been presented, a specific problem has been considered. It is desired to produce the plant design (subsystems 1 and 2) which minimizes the normalized operating cost for the generation of 600 MW, for ten hours each weekday, by utilizing the Media, Illinois Galesville aquifer as the reservoir. Contour maps and material properties for this aquifer, and other problem parameters, are given in references by Sharma [1], Katz [9], and Ahluwalia [16].

The subsystem 1 problem was solved, for a number of combinations of p_1 and $\dot{m}'$, using the BIAS [11] nonlinear programming code, which is an implementation of the Method of Multipliers. The initial values of design variables were chosen by engineering judgement. The BIAS algorithm does not require the inital point to be a feasible design. It should be noted that the BIAS code contains a variable scaling algorithm, which proved to be essential in getting problem solutions.

Contours of constant minimized operating cost for subsystem 1 are shown in Figure 5. A very significant cost variation is evident. The steeply rising cost at high pressure reflects the presence of a constraint, built into the aquifer mathematical model rather than appearing directly in the optimization problem constraint definitions. This constraint insists that the mean weekly pressure in the aquifer should equal its natural "discovery" pressure (840 psia in this example) in order to maintain a constant mean air storage volume. Figure 5, indicates that small $\dot{m}'$ values (i.e., low air flow rates) are favored. This is due primarily to the higher cost of the air storage reservoir as the quantity of air stored is increased.

The optimum subsystem 1 designs corresponding to points in Figure 5 were also found to vary widely. Of particular interest is the number of wells required. It was found to vary from a low of 54 in the lower left (low cost) region to values in the 200-500 range in the upper right region. Finally, it is noted that the effects of the discrete variables (low pressure compressor compression ratio, wellbore diameter, and main pipe diameter) have been studied, for one set of coupling variables, and are reported by Ahrens [21]. The only significant one of these is wellbore diameter. Cost increases with increasing diameter. For the present optimizations, these discrete variables were held fixed at optimum or near-optimum values.

The subsystem 2 problem was solved, for many combinations of p_1 and $\dot{m}'$, using the nonlinear programming code, OPT [14], which is based on the generalized reduced gradient method. A problem solution is initiated by specifying the coupling variables and trial values for T_5, ε and r_p. The subsystem model equations are solved by an iteration method, to yield the value of T_3. If this initial T_3 value violates constraint equation 3.19, OPT performs a "Phase 1" search for a combination of T_5 and ε which minimizes the square of the constraint violation. If this procedure yields a feasible starting point, the reduced gradient iterations begin; if not, the problem solution attempt is terminated (i.e., it is assumed that no solution exists for the problem as specified).

Contours of constant minimized operating cost for subsystem 2 are presented in Figure 6 for a range of p_1 and $\dot{m}'$ values. The minimum cost contour (22 mills/kWh) corresponds approximately to designs having the minimum allowed (1500°F) turbine inlet temperatures, T_3 and T_5. These correspond to conventional designs proposed for CAES plants. The maximum cost contour (24.5 mills/kWh) shown is near to the constraint boundary representing the upper limit (2400°F) on turbine inlet temperatures. These are advanced designs requiring considerable cooling air. From the overall system viewpoint, the advantage of these turbines is that they reduce the amount of air which must be stored (proportional to $\dot{m}'$), thus reducing the reservoir cost.

The results in Figure 6 are based on $r_p = 16$. It was found that use of $r_p = 11$ yielded similar, but slightly higher, cost results throughout the region explored. The optimum recuperator effectiveness, ε, was found to vary from 0.52 to 0.77 for the ranges of coupling variables yielding solutions. The most common value encountered was on the order of 0.7.

By the nature of the decomposition strategy employed in the CAES design problem, the optimum CAES plant - that design which minimizes the power generation cost for the specified utility load cycle and aquifer site - may be easily found by superposing the results from Figures 5 and 6. The resulting minimized cost contours are shown in Figure 7. Interestingly, even though the individual subsystem contours are open, their sum exhibits an overall optimum which is within the coupling variable domain considered. Figure 7 demonstrates that the power generation (operating) cost of the optimum CAES plant is slightly under 37.75 mills/kWh, and that the optimum values for the coupling variables are, approximately, $p_1 = 625$ psia and $\dot{m}' = 8.5$ lbm/kWh. Knowing the optimum coupling variables, one can readily obtain the optimum values of other design variables from the separate subsystem 1 and 2 optimization results. These, and some pertinent dependent variable values, are indicated in Table 1. The associated cost components for the optimum design are given in Table 2.

It is of interest to note that the constraints active at the problem solution were the three defined by equations 3.10, 2,5,7. These state that: (a) the wells should be separated by the maximum spacing consistent with efficient aquifer utilization (as dictated by unsteady flow considerations), (b) the wells should penetrate as deeply into the air bubble as would just avoid water coning into the wellbore during a discharge process, and (c) the reservoir pressure should be allowed to fall to a weekly minimum value which just permits flow to the turbines with no excess driving force. In addition, the low pressure turbine inlet temperature (T_5) is at its upper bound (2400 ^{o}F) at the solution. The charging time durations were found to take their maximum allowed value on weeknights, but not on the weekend.

5. Discussion

The optimal design approach affords a significant opportunity for cost savings in the construction and operation of compressed air energy storage systems; as can be seen from the previously given results. On the other hand, the models necessary to adequately represent such a practical physical system can be quite complex. We have given what we feel to be the least complex system model, which will produce a meaningful optimal design. Even with our simplified approach the complete CAES system optimization (including subsystems 1 and 2) involves 20 design variables, 4 discrete design parameters, 8 linear constraints, 5 nonlinear constraints, upper and lower bounds on all design variables, and a nonlinear objective function. Furthermore, the model includes functions which require calculation of the modified Bessel functions of the first and second degree and first and second kind, and various spline approximations for empirical data.

We expected the full CAES problem (that is, including subsystems 1 and 2) to provide a significant challenge to modern nonlinear programming methods. We sought relief in decomposition theory, whereby the largest NLP contained 16 design variables, 12 constraints, variable bounds and a nonlinear objective. We did, of course, have to solve the resulting optimization problems for various values of the coupling variables. Our experiments with subsystem 1 and 2 support our original fears concerning the difficulty of the complete CAES problem. Furthermore, the subsystem optimization problems have value within themselves. That is, these subgroup results provide insights that would be difficult at best to gather in any other way. Finally, the decomposition strategy employed here allows an orderly modular approach of design to be employed. That is, we might envision a different storage system (such as a hard rock cavern) which would produce a different subsystem 1 model. We could perform the subsystem 1 optimizations and synthesize the overall system results just as before. That is, the subsystem 2 results would be unaffected.

The results presented in Figures 5,6, and 7 demonstrate an interesting consequence of the decomposition strategy. Subsystem 2 results show a very simple dependence on the coupling variables which is intuitively satisfying. Subsystem 1 results also show a somewhat simple variation with changes in p_1 and $\dot{m}'$. Interestingly, neither of the subsystems had an optimum inside the design space explored. However, once the two subsystem results were combined, a distinct minimum was found.

Another benefit of decomposition in this particular problem is that for the purpose of plant site selection, only subsystem 1 results would be site-dependent. When one of many available sites has to be selected, as is the case with a proposed CAES pilot plant in Indiana or Illinois, the geological and cost data for the various aquifers can be input to the procedure and the optimal designs of subsystem 1 at various sites can then be compared in making the final decision. However, since different sites might have different base electricity cost, etc., a consideration of the interactions of subsystem 1 and 2 with subsystem 3 may be important to the evaluation.

It is noteworthy that the technical and economic modeling of subsystem 1 and 2 was performed by two teams working relatively independently, and in parallel. The decomposition approach enabled a rather straightforward way of integrating these efforts into an overall system optimization capability.

An interesting aspect of the optimization of subsystem 1, showing the great value of optimal design, is as follows. The authors originally felt, based on engineering judgment, that the CAES plant for the site assumed in this study should be designed with $p_1 \simeq 750$ psia and $\dot{m}' \simeq 10.4$ lbm/kWh. In a preliminary paper on CAES system design [1], results for an intuitive subsystem 1 design and an optimized design were presented. The former had a capital cost of $101.6 million, an operating cost of 24.25 mills/kWh and 700 wells, while the latter had a $62 million capital cost, 19.36 mills/kWh operating cost and 402 wells. Finally, referring to information in Tables 1 and 2, it was found that the subsystem 1 design at system optimum had a capital cost of only $22.26 million, an operating cost of 12.51 mills/kWh and only needed 54 wells!

The subsystem 2 results in Figure 6 show that the cost decreases with increasing specific turbine air flow rate ($\dot{m}'$). The nature of the turbine cost functions are such that the lower cost region corresponds to lower turbine inlet temperatures. Thus, from the standpoint of subsystem 2 cost, conventional turbines tend to be favored over advanced, high temperature turbines. Interestingly, in a study which considered design of CAES plants having water-compensated (constant pressure) hard rock caverns for air storage [20], it was likewise concluded that no significant power generation cost advantage results from the use of advanced, undeveloped, turbines. This same conclusion was later drawn for salt cavern and aquifer reservoir based plants [22] when the cost of these reservoirs was simply represented as a fixed fraction of the equivalent hard rock cavern cost. The cost results in Figures 6 and 7 (based on a far more detailed aquifer reservoir model) indicate, however, that considerable care must be taken in applying conventional, lower temperature turbines or a large economic penalty could result. That is, only if one keeps the inlet pressure, p_1, near its optimum value ($\approx$ 625 psia in this example), could one go to a higher than optimum $\dot{m}'$ value (lower inlet temperatures) without too much cost increase relative to the optimum design (which required a 2400 $^{\circ}$F low pressure turbine).

The results which were presented in Section 4 were based on a fixed set of cost parameters for the various system components. Obviously, variations in these parameters can be considered in an extended design study in order to determine the sensitivity of the plant economics and design to uncertainties in their values. Effects of base plant electricity costs and of well-field land costs, as examples, are shown in Figures 8 and 9, for the case of an optimum subsystem 1 configuration when p_1 = 750 psia and $\dot{m}'$ = 10.4 lbm/kWh. Interestingly, it was found that the optimum design variables did not change as these costs were varied, thus explaining the linear relationships in the figures. Although this observation may not be of general validity, it would be comforting to know that a CAES design would remain optimum if the cost of base-plant electricity were to increase in the future!

To achieve a more comprehensive CAES design procedure some aspects of the economic models and some technical models can be improved. For example, a more detailed piping model should be introduced with accompanying cost modeling. Also, a differential cost policy for the active and non-active (over the bubble) land areas could be adopted. Another area which would appear to be beneficial is the definition of the aquifer coning constraint. A major remaining task is the development of a suitable model for subsystem 3. This would permit variations in available storage time, plant availability, and more realistic load cycles to be evaluated [23].

In conclusion, it can be stated that a computer-aided optimal design technique has been developed, and applied,for design of a complex power system with energy storage. The results presented demonstrate the great value of the optimization approach, in general, and of the decomposition method, in particular, for this type of system.

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Table 1. Optimum CAES Plant Design

Number of wells	54
Active well-field area (acres)	276.1
Air bubble thickness (ft.)	69.75
Average active formation thickness (ft.)	45.45
Wellbore diameter (in.)	7.0
Surface area to be purchased (acres)	1973
Main piping diameter (in.)	48
Total weekly storage time (hrs.)	52.1
Compressor power required (MW)	371
Compressor system discharge pressure (psia)	969
Low pressure compressor pressure ratio	11.0
Recuperator effectiveness	0.715
Low pressure turbine inlet temperature (^{o}F)	2400
High pressure turbine inlet temperature (^{o}F)	1625
Premium fuel heat rate (Btu/kWh)	4230
Inlet pressure to subsystem 2 (psia)	625
Specific turbine system air flow rate (lbm/kWh)	8.5

Table 2. Costs of Optimal CAES Plant

	Capital Items ($$10^6$)
Land Cost	2.959
Piping	3.449
Bubble Development	1.407
Well Construction	5.637
Low Pressure Compressor	4.486
Booster Compressor	4.656
Recuperator	3.102
Turbine System	12.553
Balance-of-Plant	42.000
Total Capital Cost	80.249
Other	
Base Load Electricity (mills/kWh)	9.662
Premium Fuel (mills/kWh)	10.723

Subsystem 1 operating cost	12.51	
Subsystem 2 operating cost	23.12	
Total power generation cost	35.63	mills/kWh

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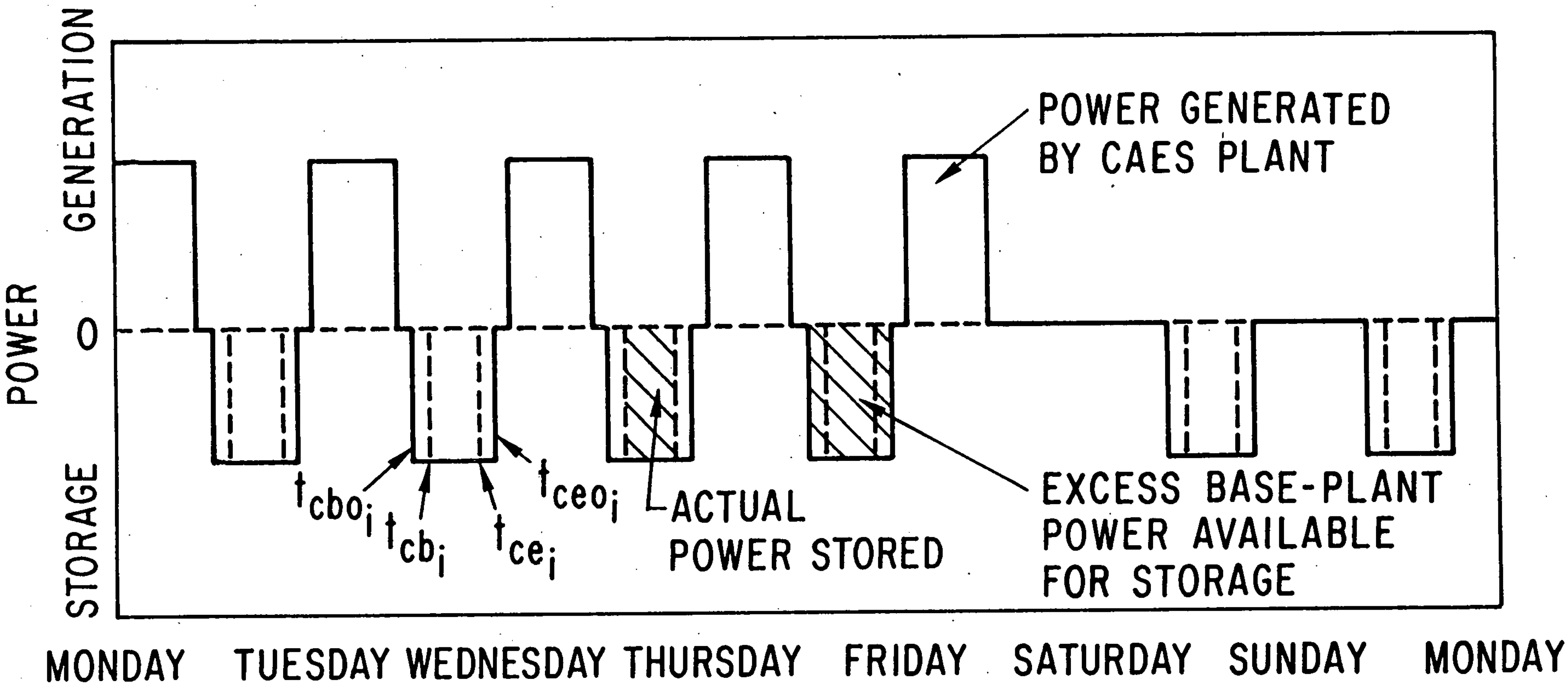
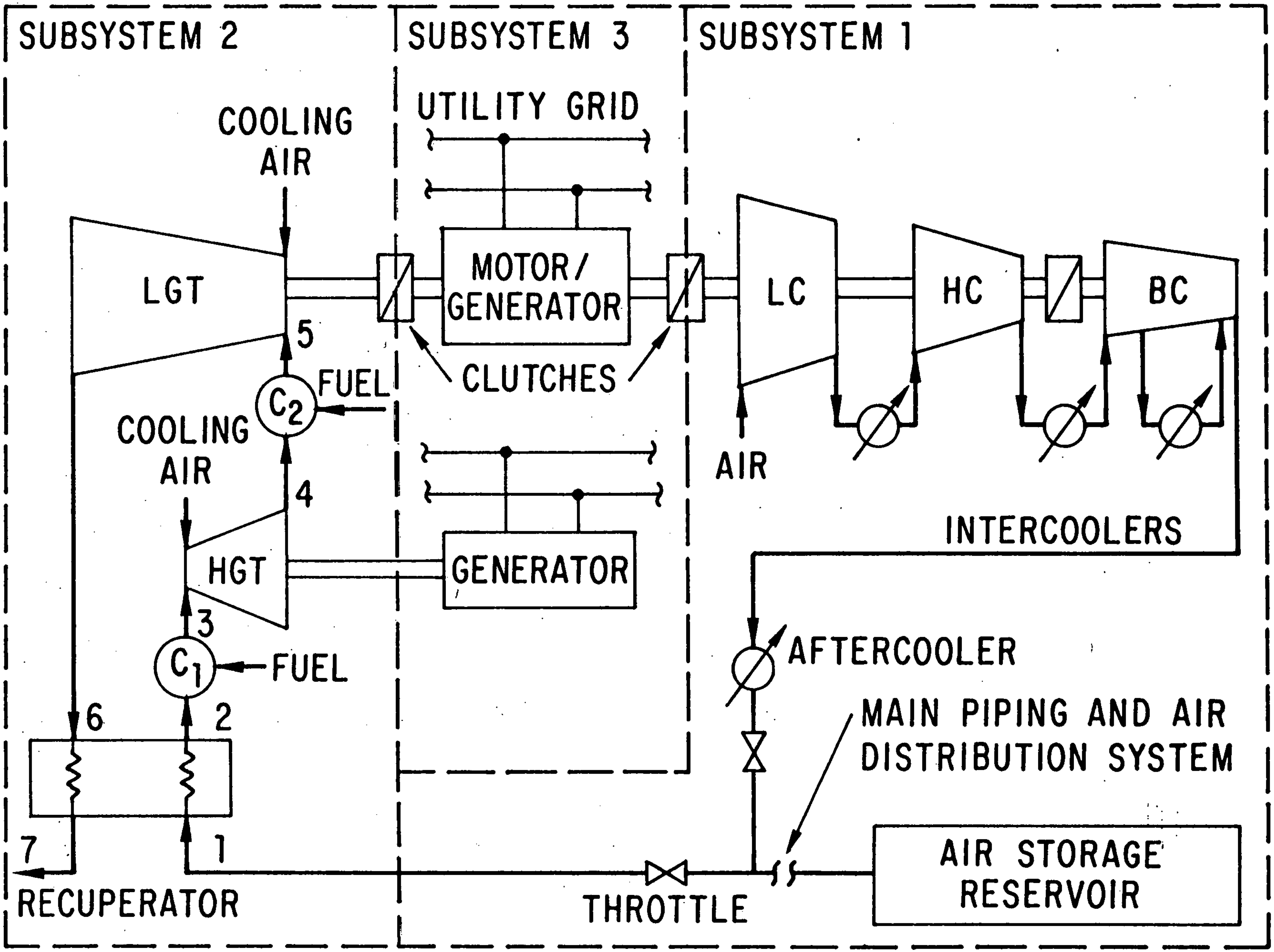
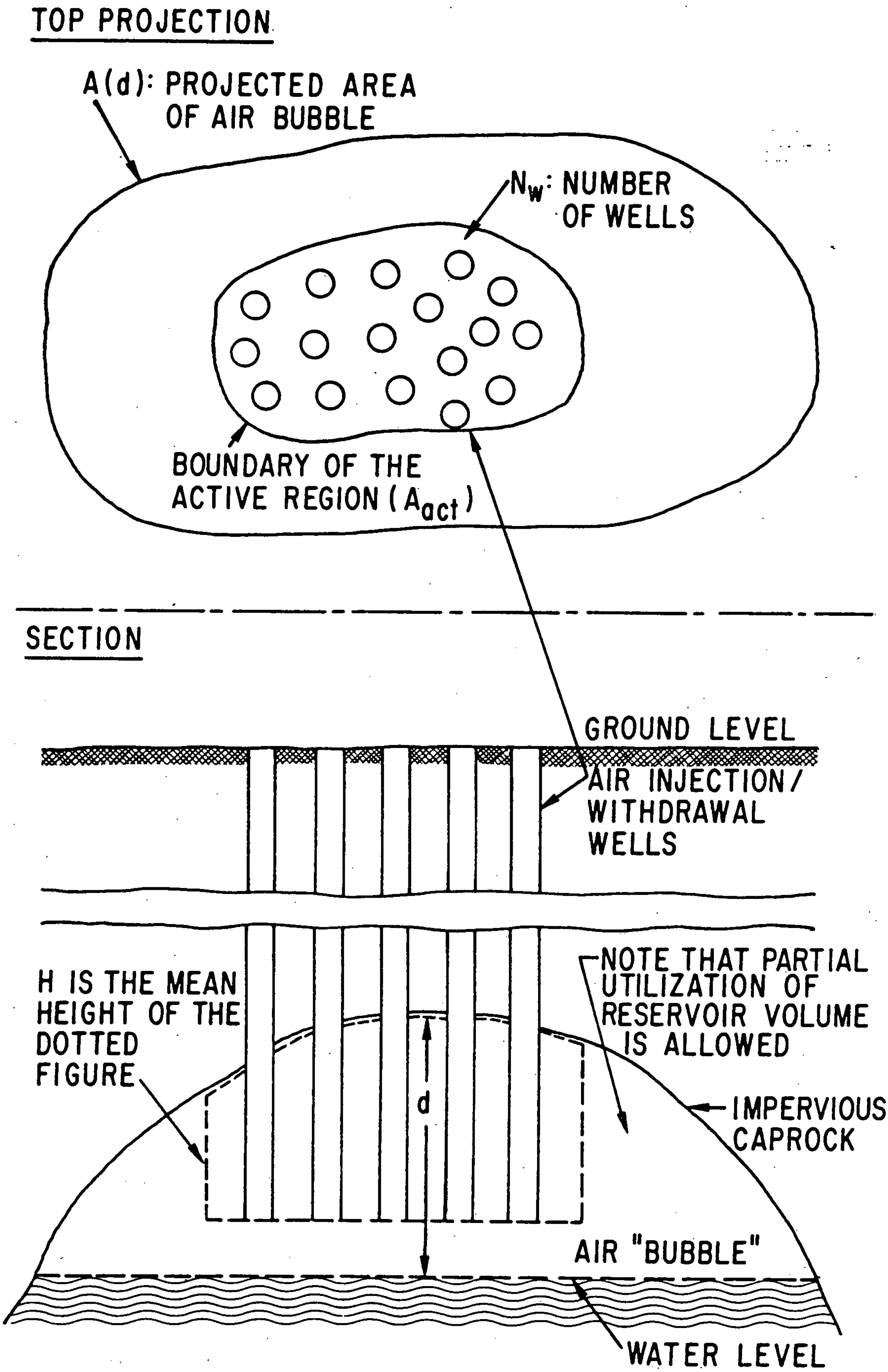
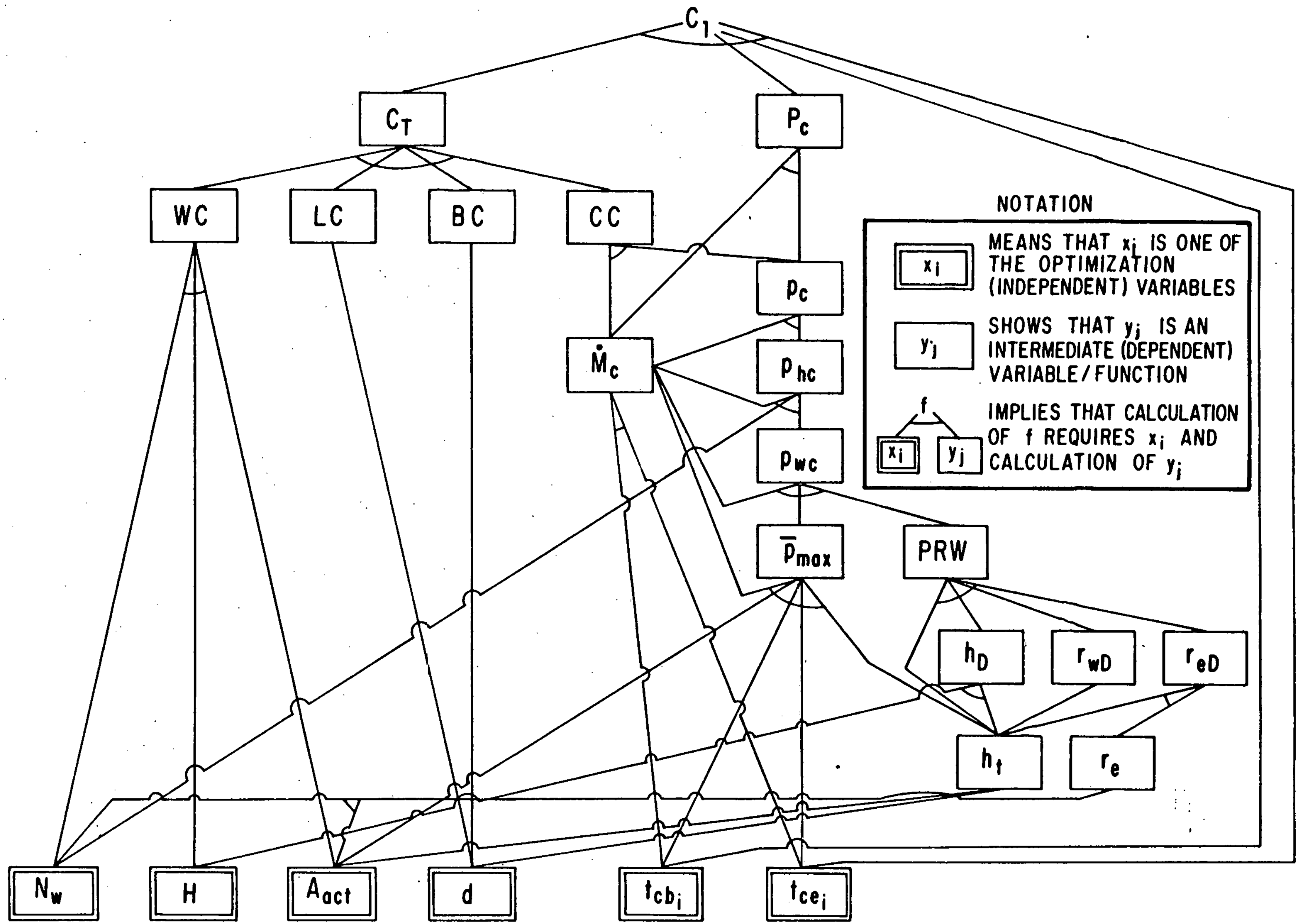
List of Figures

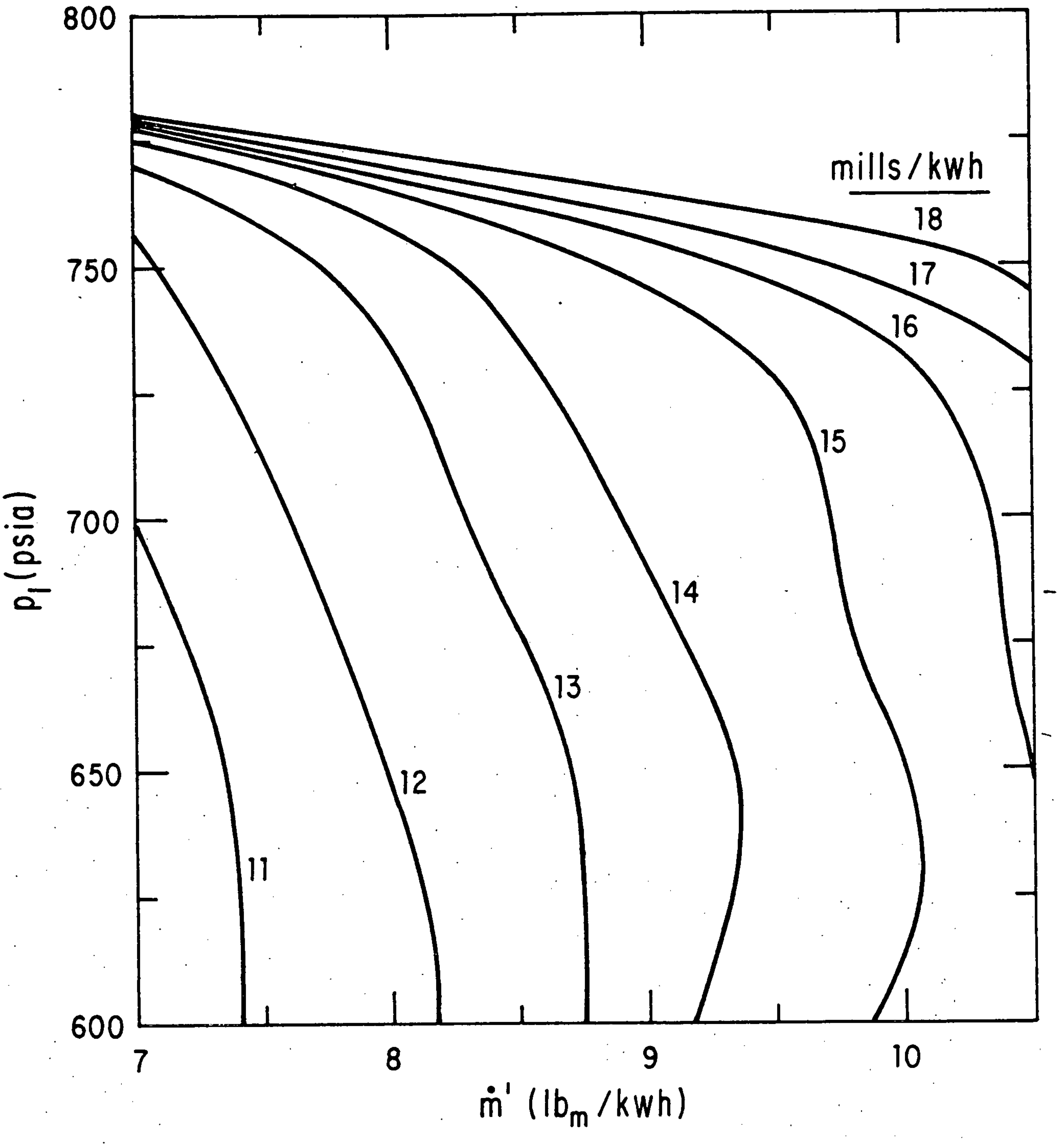

POWER
GENERATION
0
STORAGE
POWER GENERATED BY CAES PLANT
t_{cbo_i}
t_{cb_i}
t_{ce_i}
t_{ceo_i}
ACTUAL POWER STORED
EXCESS BASE-PLANT POWER AVAILABLE FOR STORAGE
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
SUNDAY
MONDAY


SUBSYSTEM 2
SUBSYSTEM 3
SUBSYSTEM 1
UTILITY GRID
COOLING AIR
LGT
MOTOR/ GENERATOR
LC
HC
BC
5
FUEL
CLUTCHES
C2
COOLING AIR
4
AIR
HGT
GENERATOR
INTERCOOLERS
3
C1
FUEL
AFTERCOOLER
6
2
MAIN PIPING AND AIR DISTRIBUTION SYSTEM
7
1
AIR STORAGE RESERVOIR
RECUPERATOR
THROTTLE


TOP PROJECTION
A(d): PROJECTED AREA OF AIR BUBBLE
N_W: NUMBER OF WELLS
BOUNDARY OF THE ACTIVE REGION (A_{act})
SECTION
GROUND LEVEL
AIR INJECTION/ WITHDRAWAL WELLS
H IS THE MEAN HEIGHT OF THE DOTTED FIGURE
NOTE THAT PARTIAL UTILIZATION OF RESERVOIR VOLUME IS ALLOWED
d
IMPERVIOUS CAPROCK
AIR "BUBBLE"
WATER LEVEL



C1
CT
Pc
WC
LC
BC
CC
pc
Ṁc
phc
pwc
p̄max
PRW
hD
rwD
reD
ht
re
Nw
H
Aact
d
tcbi
tcei
NOTATION
xi
MEANS THAT xi IS ONE OF THE OPTIMIZATION (INDEPENDENT) VARIABLES
yj
SHOWS THAT yj IS AN INTERMEDIATE (DEPENDENT) VARIABLE/FUNCTION
f
xi
yj
IMPLIES THAT CALCULATION OF f REQUIRES xi AND CALCULATION OF yj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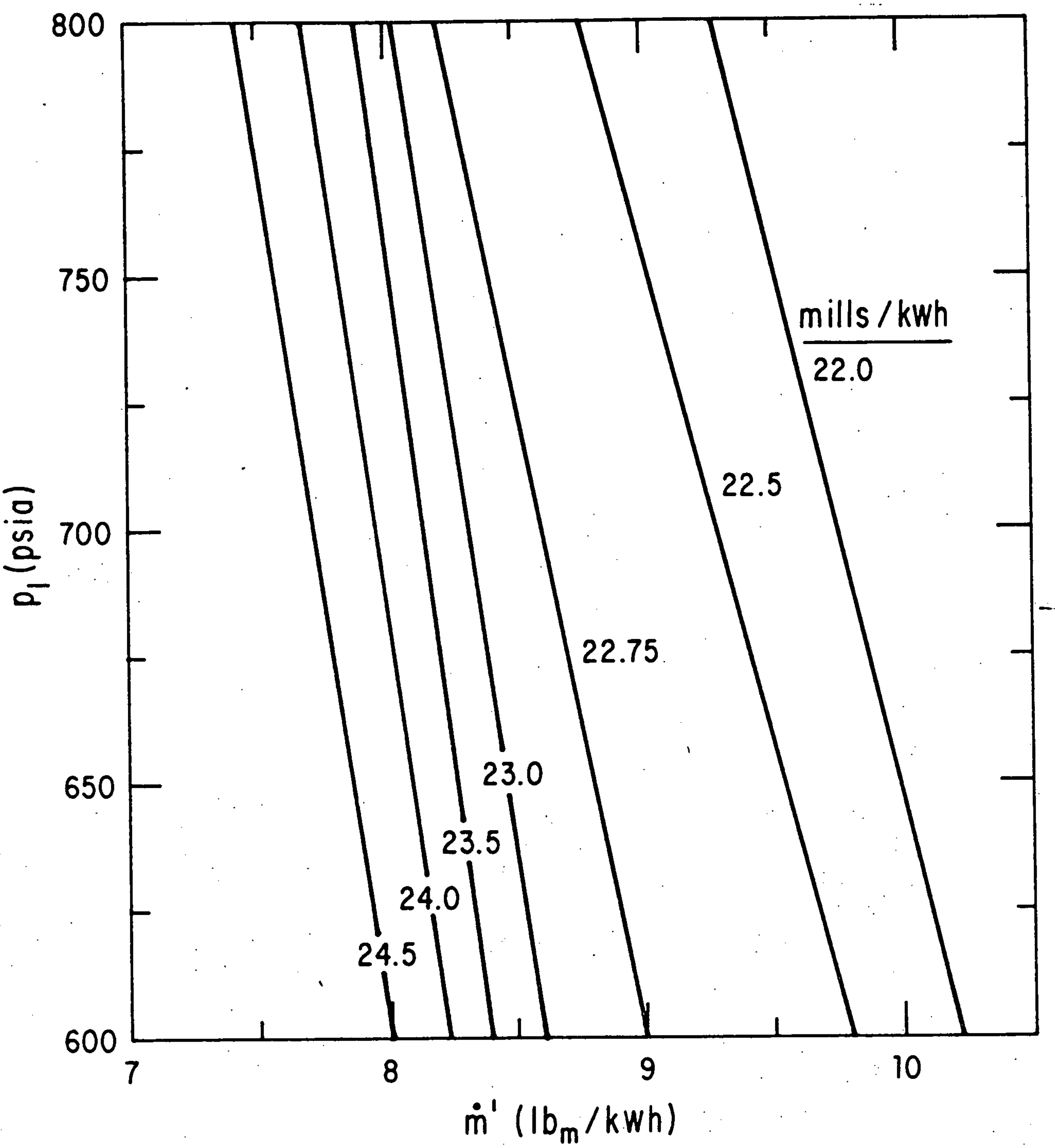
750
700
650
600
p_1 (psia)
7
8
9
10
$\dot{m}'$ (lb_m/kwh)
mills/kwh
18
17
16
15
14
13
12
11


800
750
700
650
600
p_1 (psia)
7
8
9
10
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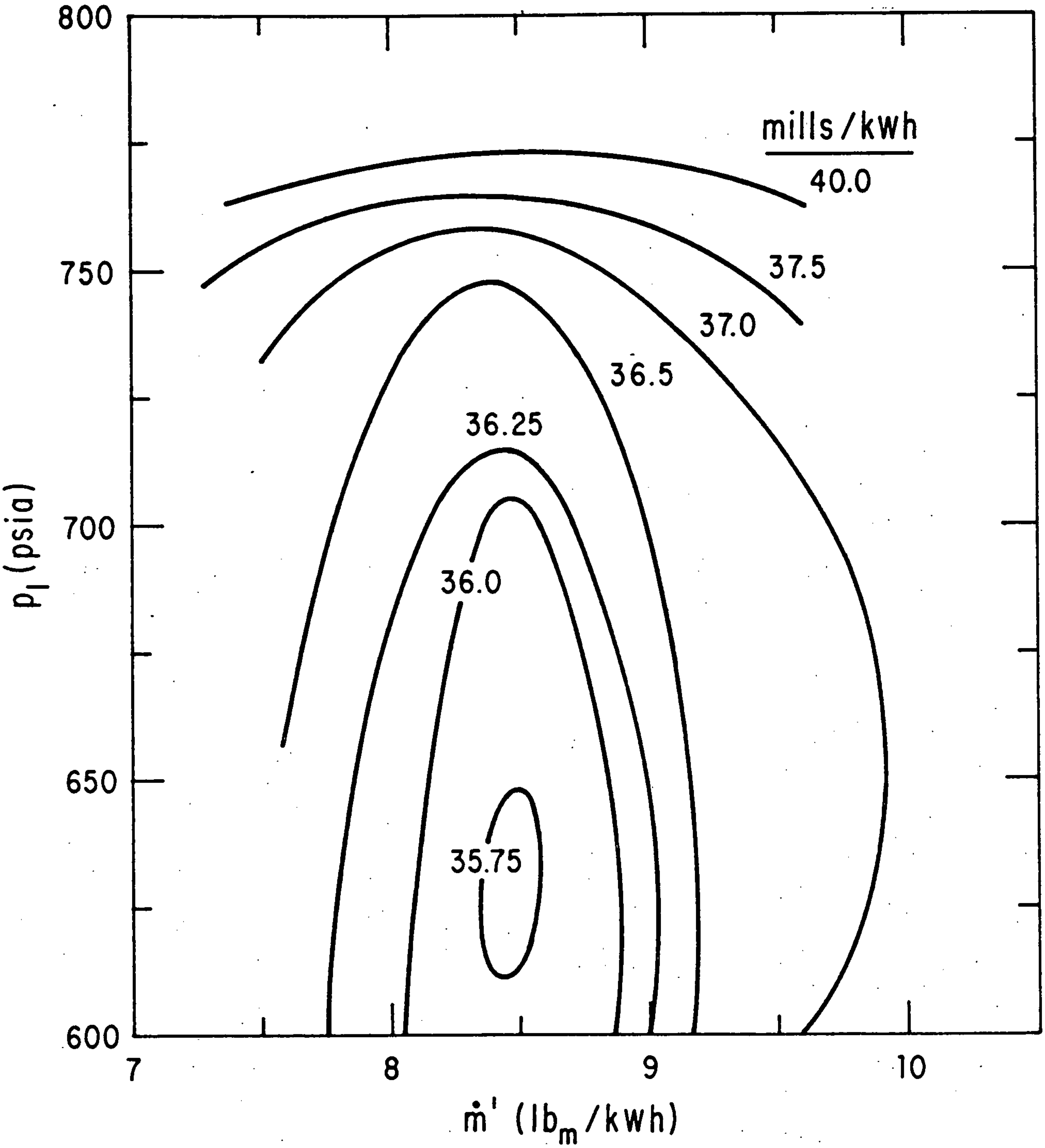
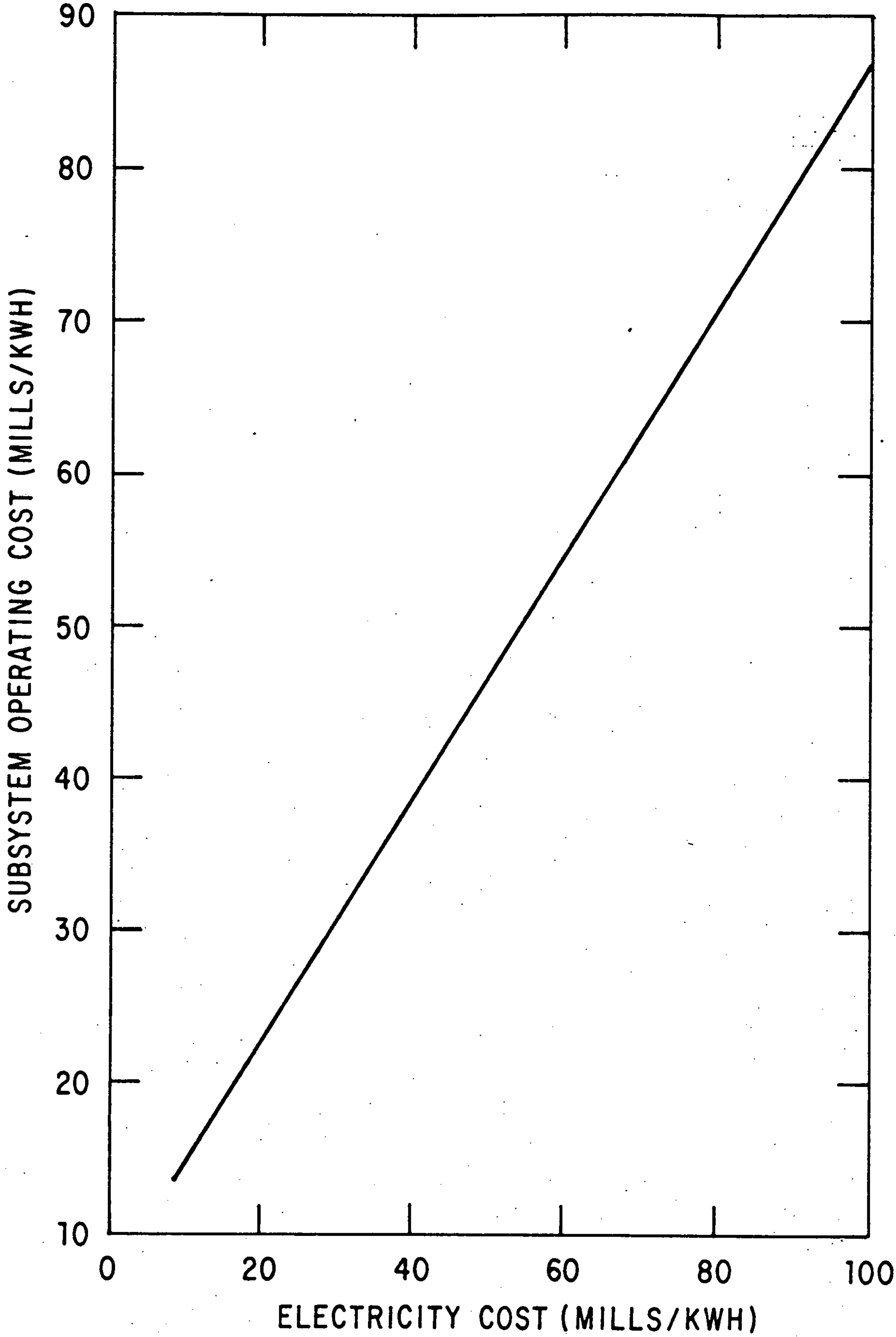
22.5
22.75
23.0
23.5
24.0
24.5



mills / kWh
40.0
37.5
37.0
36.5
36.25
36.0
35.75
800
750
700
650
600
p_1 (psia)
7
8
9
10
$\dot{m}'$ (lb_m/kWh)


90
80
70
60
50
40
30
20
10
SUBSYSTEM OPERATING COST (MILLS/KWH)
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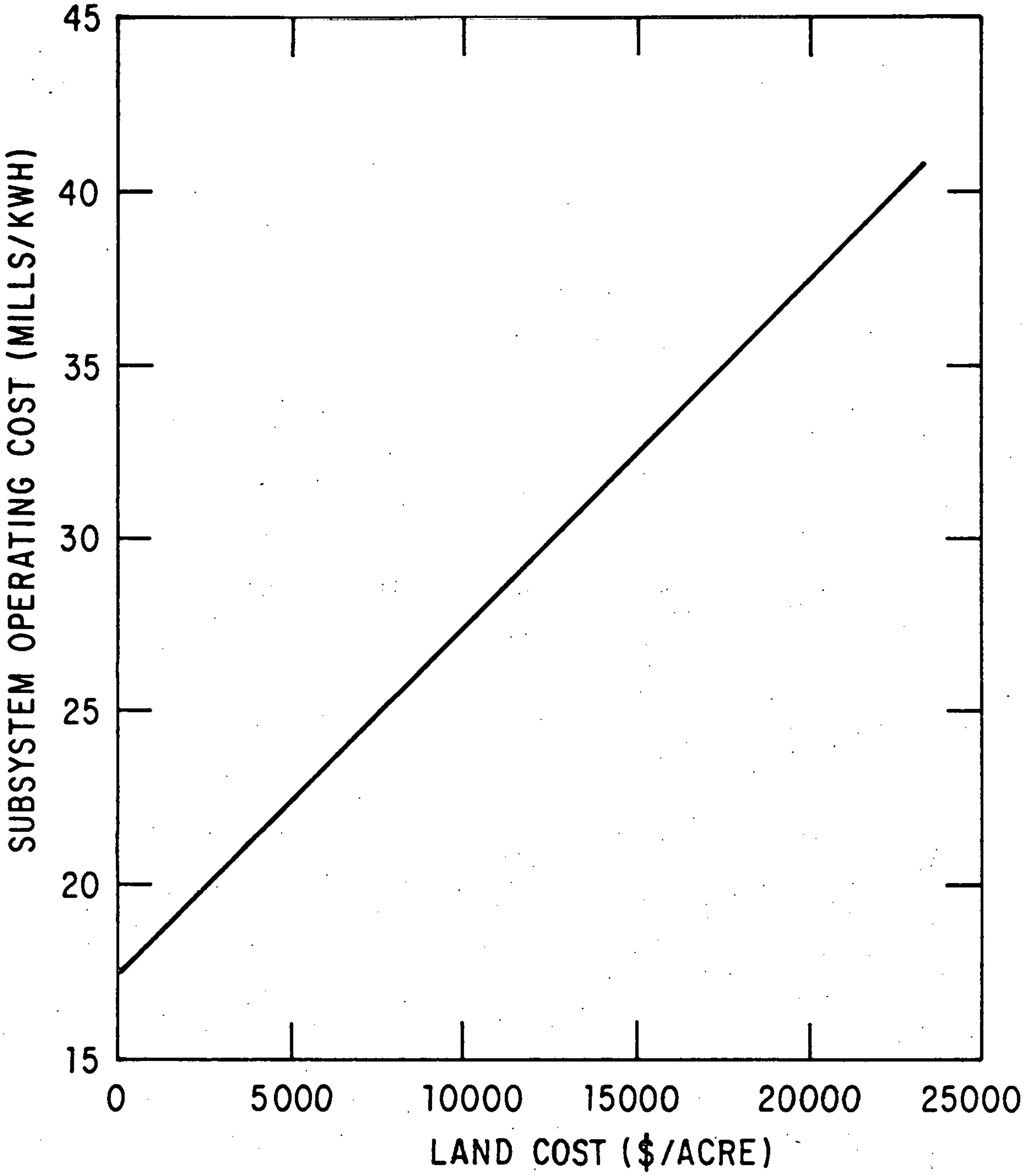
20
40
60
80
100
ELECTRICITY COST (MILLS/KWH)



45
40
35
30
25
20
15
SUBSYSTEM OPERATING COST (MILLS/KWH)
0
5000
10000
15000
20000
25000
LAND COST ($/ACRE)