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PHOTOVOLTAIC SYSTEMS CONCEPT STUDY

Final Report. Volume 5 of 5

April 1977

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Solar Energy

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FINAL REPORT
PHOTOVOLTAIC SYSTEMS CONCEPT STUDY

VOLUME V OF V

● APPENDICES

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PREFACE

This report documents the work performed in the conceptual design and systems analysis of three sizes of photovoltaic solar electric power systems. Conceptual system designs were developed for a single family residence, a central station power plant, and for two on-site intermediate systems (shopping center and commercial retrofit). The work was carried out by a team consisting of Spectrolab, Inc.; Bechtel Corporation; Ingenasu Associates--a group of faculty members from Arizona State University; Facilities Systems Engineering Corporation; and Midwest Research Institute; with Spectrolab as prime contractor and program manager.

This report has been prepared in nine sections plus appendices, separated into five separate volumes based on subject content. The following outlines the report format and section content:

Volume I Sections 1 and 2

INTRODUCTION AND OVERALL PROGRAM SUMMARY

Volume II Sections 3 and 4

DESCRIPTION OF SOLAR CELL ARRAYS, POWER CONDITIONING,
AND STORAGE COMPONENTS
DETAILED DESIGN OF RESIDENTIAL SYSTEM

Volume III Sections 5 and 6

DETAILED DESIGN OF SHOPPING CENTER SYSTEM, RETROFIT
APPLICATION, AND SIMPLIFIED ON-SITE SYSTEM DESIGN METHOD

Volume IV Sections 7, 8, and 9

DETAILED CENTRAL POWER STATION DESIGN,
ECONOMIC PERFORMANCE CHARACTERISTICS,
AND SOCIAL-INSTITUTIONAL ASSESSMENT

Volume V Appendices

REFERENCE DOCUMENTATION ON ECONOMIC MODELS
TECHNICAL DATA, AND PERFORMANCE ANALYSIS DATA

APPENDIX A

ECONOMIC THEORY, ELECTRIC UTILITIES AND PEAK LOAD PRICING

ECONOMIC THEORY, ELECTRIC UTILITIES AND PEAK LOAD PRICING

I. Introduction

One of the important tasks in evaluating the potential use of photovoltaic energy systems by electric utilities is to understand the nature of the industry. Economic theory offers a great deal of insight into the behavior of these firms. Although the existing economic literature on the subject is necessarily abstract, important overviews of the problem can still be gained.

This review is divided into four sections. After the introduction, the general theory of monopoly is presented. It is brief and intended to set the stage for the more specific subjects that follow. Section III deals with the behavior of a monopoly under regulations on the rate of return. The major conclusion of the section is that regulated monopolies tend to employ more capital equipment than is socially optimal. The conclusion is supported by both theoretical and empirical studies. The final section addresses peak load pricing. The most significant aspect of the discussion is that, in certain conditions, it may be in a utility's best interest to charge a higher price during the off-peak periods than during the peaks.

II. Economic Theory of the Unregulated Monopoly

The electric utility industry is one of the best examples of a monopoly market in the United States. It has often been termed a "natural" monopoly. That is, the characteristics of the product and the market cause the monopolist to be the most efficient producer. In terms of electricity, the monopoly avoids duplication of high cost transmission and distribution systems and makes large cost saving facilities economically feasible.

The behavior of a firm in a monopoly environment is the subject of a great deal of economic literature. The major differences between a monopoly and a competitive firm are: (1) the monopoly faces a downward sloping demand curve; and (2) the monopolist can control the price or quantity of his product. It is helpful, for the discussion that follows, to briefly review this theory.

The monopolist faces no competitors (i.e., no close substitutes) in the supply of his product. In other words, the monopolist constitutes the entire industry and faces the industry demand curve. The total revenue (TR) received by the monopolist is represented by the quantity sold (Q) times its price (P).

$$TR = P \cdot Q \quad (1)$$

The demand curve facing the monopolist is represented by:

$$Q = f(P)$$

and $dQ/dP < 0$. In other words, the monopolist faces a negative sloped demand curve in which the quantity demanded decreases as the price increases.

The marginal revenue curve facing the monopolist represents the additional revenue attainable from selling one more unit of output. If the quantity demanded did not change with price, similar to the situation facing the small competitive seller ($dQ/dP = 0$), the marginal revenue would equal the price. In other words, the additional revenue gained from selling another unit of output would equal its selling price. However, once the monopolist has supplied the demand at a given price, he must lower the price of all units to increase sales. His marginal revenue is therefore the gain from the additional sales minus the decreased revenue resulting from the lower price. The monopolist's marginal revenue will therefore be less than the selling price. Algebraically, the marginal revenue is the first derivative of the total revenue curve.^{1/}

$$TR = P \cdot Q$$

where $P = f(Q)$

$$\frac{dTR}{dQ} = P + \frac{dP}{dQ} \quad \dots (2)$$

where $\frac{dP}{dQ} < 0$

^{1/} Henderson, James, and Richard Quandt, Microeconomic Theory - A Mathematical Approach, 2nd Edition (McGraw-Hill, NY, NY, 1971), pp. 209-210.

The relationship between demand and marginal revenue can be expressed graphically. Figure 1 shows a linear demand curve (DD) and the corresponding marginal revenue curve (MR).

Figure 1 - Monopoly Demand and Marginal Revenue Curve

For any quantity on the horizontal axis, the total revenue is represented by the area of the rectangle found by the quantity and corresponding price given by the demand curve. For example, the total revenue associated with Q_1 is the area Q_1AP_1O in Figure 1.

The cost curve facing the monopolist is of the same general form as that encountered by the competitive firm. The total cost (TC) is an increasing function of the quantity produced and is expressed below. It includes both fixed and variable costs, as well as labor and capital costs.

$$TC = C(Q) \quad \dots(3)$$

The marginal cost curve is the incremental cost of producing one more unit of output. It is represented by the first derivative of the cost curve with respect to quantity.

$$MC = \frac{dTC}{dQ} = C'(Q) \quad \dots(4)$$

where MC = the marginal cost

Graphically, a typical marginal cost curve is shown in Figure 2. The additional cost of producing more output decreases over the lower range of production. As production increases the additional cost begins to increase. As production nears the capacity of the capital equipment the additional costs increase progressively faster.

Figure 2 - Typical Shape of a Marginal Cost Curve

The objective of the monopolist is to alter the quantity or price of his product to maximize profits. Algebraically:

$$\max_{Q \text{ or } P} \pi = TR - TC$$

$$\max \pi = PQ - C(Q) \quad \dots(5)$$

where π = profit

The maximization is carried out by taking the first derivative of the profit equation with respect to Q or P and setting it equal to zero.^{2/}

$$\pi = P \cdot Q - C(Q)$$

$$\frac{d\pi}{dQ} = P + Q \frac{dP}{dQ} - C'(Q) = 0$$

$$= MR - MC = 0$$

$$\therefore MR = MC$$

...(6)

The familiar result of equating marginal cost and marginal revenue is obtained. The quantity and price resulting from the equality are shown in Figure 3.

Figure 3 - Profit Maximization Solution for Unregulated Monopoly

^{2/} It is also assumed that the second derivative is negative.

The marginal cost curve (MC) intersects the marginal revenue curve (MR) at point A in Figure 3. The optimal quantity produced by the monopoly is given by Q_2 . The maximum price that the monopolist can charge for the quantity Q_2 is given by point B on the demand curve (DD) (i.e., price P_2). The total revenue received by the monopolist is $P_2 \cdot Q_2$ or the area Q_2BP_2O in Figure 3.

If the market was perfectly competitive each producer would equate marginal cost and price. This intersection is given by point C in Figure 3. The quantity Q_3 would be produced and sold at price P_3 . In other words, under a competitive market a larger output would be produced. In addition, it would be sold at a lower price.

The discussion to this point has focused only on short run analysis. The short run is defined as a period of time short enough so that no changes in the size or amount of capital equipment employed can be altered. In the long run both labor and capital inputs into the production process can change. A similar set of cost curves exist in the long run. Figure 4 presents a typical family of both short and long run cost curves.

Figure 4 - Long Run Equilibrium of an Unregulated Monopoly

Long run equilibrium is attained when marginal revenue and long run marginal cost are equal (Q^* in Figure 4). The short run cost curves associated with Q^* are shown with dotted lines. Note that the short run and long run marginal cost curves are equal at Q^* . The short and long run average cost curves are also equal at Q^* . At the price P^* a long-run monopoly profit is realized because the demand curve lies above the long run average cost curve at Q^* .

III. Theory of Monopoly Under a Regulatory Constraint

The electric utility industry faces regulations on its rate of return. The regulations are designed to protect the public from excessive monopoly profits by limiting the utility to a "fair" rate of return on capital investment. The rate of return on capital is defined as the net revenue (total revenue minus operating costs) divided by the investment in capital equipment and facilities.

A number of important studies have addressed how monopoly behavior changes with the addition of this constraint.^{3,4/} One of the easiest to comprehend is the graphical approach presented by Stein and Borts.^{5/} The approach will be used below to explain the major conclusions of the literature in the area.

Three major conditions are usually assumed to hold in the theory of a regulated monopoly.^{6/} First, it is assumed the firm attempts to maximize profit. Second, the rate of return regulation is binding. That is, the regulated rate is higher than current market interest rate and less than the firm's attainable unregulated rate of return. Finally, the firm is assumed to supply the quantity of its output demanded at the equilibrium market price.

The major conclusions of the theory are derived by returning to the firm's long run cost curves. Figure 5 presents the firm's operating position without regulation.

3/ Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," American Economic Review (December 1962) pp. 1052-1069.

4/ Takayama, A., "Behavior of the Firm Under Regulatory Constraint," American Economic Review (June 1969), pp. 255-260.

5/ Stein, J., and G. Borts, "Behavior of the Firm Under Regulatory Constraint," American Economic Review (December 1972), pp. 964-970.

6/ Ibid, p. 965.

Figure 5 - Optimal Output and Price of an Unregulated Monopoly

The firm would produce where the long run marginal cost (LRMC) is equal to marginal revenue (MR). The equality is represented by Q_1 in Figure 5. Price P_1 is charged. The amount of capital equipment used (or the scale of plant) is K_0 . The short run average cost curve associated with the scale of plant K_0 is $SRAC(K_0, r)$. The short run marginal cost is $SRMC(K_0)$. The rate of return on K_0 is r . Without regulation the firm maximizes profit at Q_1 and meets all demand facing him at price P_1 .

When the regulatory constraint is added, the firm will not choose to employ only K_0 capital equipment. The regulated rate of return is designated as " s " and according to the previous condition it is assumed that:

$$i < s < r \quad \dots(7)$$

where i = market interest rate

s = regulated rate of return

r = unregulated rate of return

Limiting the return to "s" can be interpreted as a reduction in the price of capital. The marginal costs of production would not be affected since there is no change in variable costs. However, the fixed costs are reduced by $(r - s)K_0$ so the average cost curve declines. The new average cost curve is denoted as $SRAC(K_0, s)$ in Figure 6.

Figure 6 - The Effect of a Rate of Return Regulation on the Short Run Average Cost

The firm must adjust its scale of plant or capital investment in order to meet the three criteria listed above. If the scale of plant remains at K_0 he must charge P_1 to maximize profits. However, to hold the rate of return at "s" he must charge price P_2 (equal to the average cost of production with "s" rate of return). If the firm decides to charge price P_2 and produce only Q_1 a shortage will develop because the firm has not supplied the total quantity demanded at the price P_2 (represented by Q_2 in Figure 6).

All three conditions can be met if the scale of plant is increased to some value K_1 so that the cost curves are similar to those shown in Figure 7.

Figure 7 - Increase in the Scale of Plant Due to the Regulatory Constraint

If the short run marginal cost at the new scale of plant K_1 ($SRMC(K_1)$) is equated to marginal revenue (point A in Figure 7) the quantity Q_3 will be produced. To clear the market at quantity Q_3 , a price of P_3 must be charged. If price P_3 is charged and it equals the average cost of production at Q_3 (point B in Figure 7), the rate of return on capital remains at "s". Therefore, if the quantity Q_3 is sold at price P_3 , then all three criteria are met. The firm (a) has maximized profits, (b) is receiving a rate of return "s", and (c) supplies the total demand at price P_3 .

A number of conclusions can be obtained from comparing the behavior of an unregulated monopoly to the behavior of the same monopoly under a regulatory constraint. First, the scale of plant increases as a result of the regulation. The unregulated monopoly solution is shown in Figure 7 in dotted lines. Comparing the two solutions shows that the capital investment or scale of plant increases from K_0 to K_1 to achieve the lower regulated rate of return "s". Increasing the scale of plant increases the firm's allowable profits. Permissible profits are given by:

$$PQ - wL = sK$$

$$\frac{P \cdot Q - wL}{K} = s > 1 \quad \dots(8)$$

where w = price per unit of labor and other noncapital goods

L = quantity of labor and other noncapital goods used in the production process (e.g., labor, fuel, depreciation, etc.)

The unregulated firm is making "excess" profits given by:

$$(r - s)K \quad \dots(9)$$

The most rational means of increasing allowable profits (sK) is to increase the amount of capital K .^{7/}

Secondly, Figure 7 shows that the quantity of output the firm produces will increase with regulation. The larger quantity will also be sold at a lower price than the unregulated monopoly. This conclusion will be true as long as the marginal revenue curves slopes down over the relevant range and the short run marginal cost curve for the larger capital input (K_1) lies uniformly below the marginal cost curve associated with the smaller scale of plant (K_0).

Third, the firm no longer operates at the point of minimum cost for the given output. In other words, the firm operates at a point on the short run average cost curve that is above the long run average cost envelope. The short run marginal cost curve relevant to the regulated monopoly lies below the long run marginal cost curve. The short run marginal cost curve represents the additional cost of varying labor only while the long run marginal cost represents a change in both capital and labor. The lower short run curve implies the marginal cost of capital is greater than labor. This difference, in turn, implies the firm is not operating on its long run average cost curve.^{8/}

Using the same argument it can be shown that the capital-labor ratio increases with the regulatory constraint and becomes too large. At the new output (Q_3 in Figure 7) the short run marginal cost curve lies below the long run marginal cost and, as stated above, the marginal cost of labor is less than that of capital. The firm could become more efficient by decreasing production by employing one less unit of capital and then increasing production to the original level by employing one

^{7/} Ibid, p. 966

^{8/} All points on the long run average cost curve represent equality between the marginal cost of adding one unit of capital or labor.

more unit of labor. The net effect would be a decrease in the cost of production (i.e., more efficient production) because the marginal cost of labor is less than the marginal cost of capital.

These conclusions have undergone a great deal of theoretical scrutiny over time. Recently, quantitative evaluation of the conclusions has been attempted. Courville forwarded an approach which estimates the production function of electric utilities and then compares the implied ratios of marginal productivity to their respective prices.^{9/} The results indicate that the electric utilities are overcapitalized due to the regulatory constraint.

IV. An Economic Evaluation of Peak Load Pricing

One of the most important issues facing electric utilities today is the growth in energy demand at peak periods. Increasing energy peaks have resulted in the need for accelerated expansion of capacity by the utilities. The need for additional capacity, coupled with significant escalations in operating expenses, has led to the financial problems now facing utilities.

One of the most widely discussed solutions to the problem of peak demand growth is peak-load pricing. Under a peak-load pricing scheme, the customer is charged more per kilowatt hour for energy during peak periods than off-peak periods. The argument for this policy is that it better allocates the cost of producing peak power to the customers demanding energy during peaks. Off-peak energy users are charged a lower rate because the cost of producing off-peak energy is less. The differential pricing will better reflect the value of peak energy. Some users of peak power will change their consumption due to the price increase. As a result, the peak demand will grow less rapidly and may decline.

From a societal viewpoint, the arguments stated above are valid. However, the viewpoint of a regulated monopoly may be significantly different from that of society. In fact, Bailey and White have suggested that it may be more rational, from the utility's perspective, to charge a higher price off-peak than during the peak.^{10/}

^{9/} Courville, Leon, "Regulation and Efficiency in the Electric Utility Industry," Bell Journal of Economics and Management Science (Spring, 1974), pp. 53-74.

^{10/} Bailey, Elizabeth and Lawrence White, "Reversals in Peak and Off-Peak Prices," Bell Journal of Economics and Management Science (Spring 1974), pp. 75-92.

The Bailey and White argument requires additional investigation. The graphical analysis presented in the two previous sections will be used extensively in this investigation.

The cost curves facing the regulated monopolist will be simplified, as presented by Bailey and White,^{11/} to clarify the discussion. It will be assumed that the per unit operating cost for producing energy is the same over the entire production range. Therefore, the marginal cost of off-peak production is a constant, denoted as "c" in the Bailey-White formulation.^{11/} The production of peak energy will be assumed to require the acquisition of new capital. The new capital will be assumed to have a constant acquisition cost per unit of capacity, denoted as "k". The market cost of capital will be denoted as "r".^{11/} The marginal cost of producing peak power is given by the expression, $c + kr$. Both marginal cost curves are shown in Figure 8. The lower curve (c) is the off-peak cost curve and the upper curve represents peaking marginal cost.

Figure 8 - Simplified Peak and Off-Peak Marginal Cost Curves

The quantity of peak energy demanded is denoted as $\bar{X}$. The quantity of nonpeak energy is $\underline{X}$. The price of peak power is $\bar{P}$, while off-peak power has a price of $\underline{P}$. It will be assumed that the peak demand exceeds the off-peak demand and that peak demand is more elastic than off-peak demand. The demand and marginal revenue curves are shown in Figure 9.

^{11/} Ibid, p. 78.

Figure 9 - Peak and Off-Peak Demand and Marginal Revenue Curves

The marginal revenue and cost curves are combined in Figure 10. A number of important conclusions can be drawn from an examination of the figure. From a societal viewpoint, it is optimal to equate marginal cost and price. This equality leads to the most efficient allocation of the economy's resources. It is also the solution under conditions of perfect competition. Price and nonpeak marginal cost are equal at point A in Figure 10. The peak marginal cost ($c + rk$) is equal to peak demand (or price) at A. Comparing A and A shows the familiar solution that the peak price $\bar{A}$ is higher than the nonpeak price. Secondly, the quantity produced during the peak period is greater than the nonpeak quantity.

Figure 10 - Marginal Cost and Revenue Curves for Peak and Nonpeak Demand

The monopolist seeks a solution different than society. The monopolist equates marginal cost and marginal revenue to determine the quantity of output to be offered. The maximum price obtainable from the sale of the output is then given by the demand curve. Nonpeak marginal cost and revenue are equal at point B . The nonpeak quantity sold equals Q and the maximum nonpeak price would be P . The peak marginal cost and revenue are equal at $\bar{B}$, yielding an output of $\bar{Q}$. The price charged for $\bar{Q}$ would be $\bar{P}$. The figure shows that the nonpeak price is higher than the peak price. This conclusion is valid if:

1. The industry is a monopoly. In a competitive industry, the societal solution (given by A and $\bar{A}$) would prevail and the peak price would always exceed the nonpeak price.

2. The monopolist maximizes profit. If the monopolist did not maximize profit he may not have equated marginal cost and revenue.

3. The monopolist must supply the entire market at the equilibrium price. To clear the market at the optimal output quantity, the monopolist must charge the maximum price given by the demand curve.

4. The nonpeak demand is more inelastic than the peak demand. The relative elasticities are important because an inelastic nonpeak demand assures the monopolist that the quantity demanded will change very little as the price changes. The elastic peak price means the monopolist cannot raise the peak price very much before a large decrease in demand occurs.

5. The difference between peak and nonpeak marginal cost is not too large. The marginal cost curves in Figure 10 illustrate this assumption. A large difference between " $rk + c$ " and " c " would result in the peak price exceeding the nonpeak price.

The peak nonpeak price reversals discussed above could result with or without rate of return regulations. Adding the rate of return constraint increases the possibility of such price reversals. The firm is allowed to make a profit at both peak and off-peak periods until it reaches some allowable maximum. The maximum profit is determined by the amount of invested capital. Let us assume the firm is in a situation of making more profit than is allowed in off-peak sales but only covering costs at the peaks. To conform with the regulation, the firm can reduce off-peak prices to reduce profit. However, he could also lower the peak price to create a deficit during peak periods.^{12/} A deficit is defined as an excess of marginal operating costs over marginal revenue. The firm

^{12/} Ibid, p. 83.

would also increase its peaking capacity to raise its capital investment. The larger capital investment increases the monopolist's allowable profits. The off-peak price is then increased to compensate for the peak deficit and raise profits to the new allowable maximum. By taking this alternative, the monopolist increases his profit and size of the firm rather than just reducing profit. Offering a peak price lower than the marginal cost of producing peak power can be interpreted as a benefit given to peak users for allowing the utility to expand its capital investment and its allowable profits.

APPENDIX B

EVALUATING THE TOTAL COST OF AN ON-SITE SOLAR ENERGY SYSTEM

EVALUATING THE TOTAL COST OF AN ON-SITE SOLAR ENERGY SYSTEM

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Abstract

A methodology for evaluating the total or life-cycle cost of an on-site solar energy system is presented. The costs represent after-tax or effective costs realized by the owner of the energy system. The methodology addresses: (1) capital costs; (2) fuel costs; (3) maintenance and operating costs; (4) property taxes; (5) the tax benefits of depreciation; and (6) the investment tax credit. The model was developed for evaluating solar energy systems located at the point where the energy is demanded. However, the methodology also has applicability to many other types of energy systems.

1. INTRODUCTION

The 1973 Arab oil embargo and subsequent increases in the price of all types of energy have dramatically highlighted the United States' dependence on energy, and especially energy imports. Among other things, the current energy situation has led to a resurgence of interest in solar energy. The utilization of solar energy can take a variety of forms. They include (1) domestic hot water heating, (2) space heating, (3) air conditioning, and (4) the generation of electricity. Each of these applications faces numerous technical and economic barriers to their commercial development.

Midwest Research Institute has recently undertaken a study for the U.S. Congress to evaluate the use of solar energy to generate electricity.* The study dealt with the generation of electricity at the point of use (i.e., on-site) and the utilization, where economical, of the resulting waste heat to provide heating and cooling energy.

Among the many findings of the study was the conclusion that economic factors were of major significance in the commercial viability of the technology. On-site solar electric systems exhibit many economic differences from their conventional energy system rivals. The solar energy systems are more capital intensive than conventional systems and therefore have a higher initial cost. Secondly, they require very

little fossil fuel (used only as backup) and will exhibit lower operating costs than conventional units. These two major differences lead to subsequent discrepancies in taxes and other cost considerations. To evaluate the extent of these discrepancies a methodology has been developed to evaluate the total or life-cycle cost of on-site energy systems.

The methodology presented is designed to evaluate on-site solar energy systems. However, the approach is general enough to be used in a wide variety of other applications. For example, in the technology assessment mentioned above, the methodology was used to estimate the total cost of a conventional fossil energy system and a fossil "total-energy" system. The "total energy" system produces electricity using fossil fuels and utilizes the waste heat for space heating and cooling. Many other types of energy systems can also be investigated with this methodology.

2. TOTAL COST CALCULATION METHODOLOGY

Evaluating the total cost of an energy system requires that all expenses incurred in construction and operation to be taken into account. These costs include the cost of capital equipment, financing costs, maintenance and operating costs, taxes, depreciation and tax credits. Alternative energy systems can be compared on a cost basis if they produce the same quantity

* "Technology Assessment of On-Site Solar Electricity," conducted by Midwest Research Institute for the Office of Technology Assessment, U.S. Congress. The final report is to be released in early 1976.

and quality of energy at the same point in time. Since construction time varies for different systems and expenses are incurred at different times, the present value concept is utilized.

The cost function consists of six basic components. They are: (1) capital costs; (2) fuel costs; (3) maintenance and operation costs; (4) property taxes; (5) depreciation; and (6) the investment tax credit. The present values (PV) of these six components are then added to obtain the total cost estimate.

2.1 CAPITAL COSTS

The capital cost component consists of cash outlays to purchase and install the necessary equipment plus the cost of financing those expenditures over the life of the system. If the system is a solar energy system, the capital outlays would consist of items such as:

- (1) (amount of collector area in ft²) x (price/ft²)
- (2) (amount of prime cycle heat storage capacity in KWH) x (price/KWH)
- (3) (amount of space conditioning heat storage in BTU's) x (price/BTU)
- (4) (amount of solar electric equipment capacity in KW) x (price/KW)
- (5) (amount of fossil fuel electric equipment capacity in KW) x (price/KW)
- (6) (amount of fossil fuel space conditioning equipment capacity in BTU/hr) x (price/BTU per year)
- (7) (amount of solar space conditioning equipment capacity in BTU/hr) x (price/BTU/hr)
- (8) (amount of battery storage capacity) x (price/unit)

If these capital goods were all purchased and erected in the present period the installed cost of capital equipment would simply be the summation of the eight components above (denoted as K). No discount factor would be necessary.

However, a more realistic approach to the problem takes the time of construction into consideration. Let t_0 equal the present time period. (In this analysis, each time period represents one year). An accurate comparison of the cost of systems that take varying lengths of time to construct requires that all systems begin operation in the same year. Let m equal the number of years necessary to build the system with the longest construction period. Let α equal the number of years required to build the system being considered. Therefore, by definition, α is less than or equal to m . All systems will begin operation m years in the future. Construction of the longest system will begin at t_0 ($t_0 = 0$). Construction of any other system will begin at $m - \alpha$. Figure 1

illustrates this formulation.

Figure 1 - Timing Sequence of Construction and Operation of Energy Systems.

Letting k_t denote the capital expenditures in period t , we can express the necessary cash outlays, in general, as:

$$K = \sum_{t=m-\alpha}^m k_t$$

The present value of the capital outlays (K_p) is given by:

$$K_p = \sum_{t=m-\alpha}^m \frac{k_t}{(1 + c_k)^t} \quad \dots (1)$$

where: c_k = the owner's weighted cost of capital. (explained below)

The distribution of capital expenditures (k_t) over the construction period affect the present value of the capital costs (K_p). In order to determine the direction and magnitude of these effects, a series of four distinct capital outlay distributions were compared. The first distribution or cash flow pattern considered flows of equal size during each year of construction (see figure 2).

Figure 2 - Hypothetical Construction Outlay Pattern, Case I: Constant Outlay Pattern

The present value of this cash flow pattern is given by the expression:

$$K_F = \frac{K}{\alpha} \sum_{t=(m-\alpha)}^m \frac{1}{(1+c_k)^t} \quad \dots (2)$$

where: K_F = the dollar amount that will have to be financed.

The second case considered cash flows that increase each year. That is, the capital expenditures in each period would exceed those of the preceeding period. The largest yearly outlays would occur in the last year of construction. Figure 3 approximates this situation using a step function.

Figure 3 - Hypothetical Construction Outlay Pattern, Case II, Increasing Outlays

The third case represents a cash flow pattern which is just opposite the situation in Case II. Capital expenditures are the highest in the first year of construction and decline throughout the rest of the construction period. The last period of construction therefore contains the smallest amount of capital outlays. Figure 4 illustrates this situation.

Figure 4 - Hypothetical Construction Outlay Pattern, Case III: Decreasing Outlays

The final example considered is a peaked distribution of outlays. In the early years of construction, cash outlays are relatively small. As the project continues, outlays per period increase. As the project nears completion, the outlays taper off (see Figure 5).

Figure 5 - Hypothetical Construction Outlay Pattern, Case IV: Peaked Outlays

A comparison of the present value of each of these four example cases was accomplished by setting the discount rate (c_k) equal to 5% and the construction period at 10 years. The present value of each case is then calculated as a percentage of the total construction costs. Table I summarizes the calculations.

* Construction time refers to the number of years required to build the system. Year 1 on the axis is the year construction begins. It is equivalent to period $(m-\alpha)$ in the previous discussion. A 10 year construction time is assumed in the discussion that follows.

TABLE I

SUMMARY CALCULATIONS FOR ALTERNATIVE CONSTRUCTION OUTLAY PATTERNS

	Year									
	1	2	3	4	5	6	7	8	9	10
<u>Case I (Equal Outlays)</u>										
Percent of capital spent each year	.1	.1	.1	.1	.1	.1	.1	.1	.1	.1
Discount factor	.95	.91	.86	.82	.78	.74	.71	.68	.64	.61
Present value (Percent of capital in each year)	.09	.09	.09	.08	.08	.07	.07	.07	.06	.06
Total present value of capital	= .77 (Total capital outlays)									
<u>Case II (Increasing Outlays)</u>										
Percent of capital spent each year	.02	.04	.05	.07	.09	.11	.13	.15	.16	.18
Discount factor ($r = .05$)	.95	.91	.86	.82	.78	.74	.71	.68	.64	.61
Present value (Percent of capital in each year)	.02	.04	.04	.06	.07	.08	.09	.10	.10	.11
Total present value of capital	= .71 (Total capital outlays)									
<u>Case III (Decreasing Outlays)</u>										
Percent of capital spent each year	.18	.16	.15	.13	.11	.09	.07	.05	.04	.02
Discount factor ($r = .05$)	.95	.91	.86	.82	.78	.74	.71	.68	.64	.61
Present value (Percent of total capital in each year)	.17	.15	.13	.11	.09	.07	.05	.03	.03	.01
Total present value of capital	= .84 (Total capital outlays)									
<u>Case IV (Peaked Outlays)</u>										
Percent of capital spent each year	.03	.07	.10	.13	.17	.17	.13	.10	.07	.03
Discount factor ($r = .05$)	.95	.91	.86	.82	.78	.74	.71	.68	.64	.61
Present value (Percent of total capital in each year)	.03	.06	.09	.11	.13	.13	.09	.07	.04	.02
Total present value of capital	= .77 (Total capital outlays)									

Table I shows that the greatest difference in the total present values occur between Case II and III. This is expected since these cases represent opposite extremes of cash flows. Cases I and IV lie within these extreme values and, in this example, are identical. These latter two cases could be expected to be similar because outlays in the peaked distribution exceed the constant outlays in the middle of construction but are less in the beginning and end of the period.

This analysis gives some evidence that a constant cash outlay assumption over the construction period is not an unreasonable approximation of the more realistic peaked outlay pattern. The present value of a constant outlay pattern also lies within the extremes of the more radical patterns. Its use therefore minimizes the error created by choosing an incorrect pattern of either of the extreme cases. It is realized that the cases just described are only one set of possible examples. Alternatives using other discount rates, construction periods and outlay patterns may yield different results. However, to protect the analysis from becoming so full of detail it becomes impossible to solve, we have chosen a simplified outlay pattern. The pattern used in our analysis is expressed by $k_t = \frac{K_D}{\alpha}$ for all t .

2.1.1 Financing the Capital Investment

The options available for financing depend on the ownership and size of the energy system. For example, an on-site solar or fossil fuel energy system geared to service a community of 100,000 could be an investor-owned corporation. The corporation would buy long-term debt and issue equity in the form of common and/or preferred stock. If the same size energy system was publicly owned, the financing would probably be generated by means of long-term debt. An on-site energy system designed for a single family dwelling would probably finance construction costs only by buying long-term debt in the form of a mortgage.

A weighted cost of capital approach will be used to overcome these differences. This approach also explicitly considers differences in debt-equity mix and differentials in competing interest rates.

The weighted cost of capital approach multiplies the percentage of the corporation's capital account in each instrument times the appropriate interest rate. Let P_S equal the percentage of capital in common and preferred stocks and P_D equal the percentage in the debt instrument. The interest rate and required rate of return are given by r_D and r_S , respectively. Therefore, the weighted cost of capital is given by the expression:

$$c_k = P_D(r_D) + P_S(r_S) \quad \dots (3)$$

where: c_k = the weighted cost of capital expressed as a decimal fraction.

The weighted cost of capital (c_k) is then used as an approximation of the discount factor in the organization's present value calculations. Its major purpose is to represent the opportunity cost of money.

2.1.1.1 Corporate financing. The corporate owned firm can borrow and/or issue stocks. The mix of debt and equity actually used will depend on the size of the project in relation to the corporation, as well as the financial status of the firm. Let q_D be the percentage of the project financed with debt and let q_S be the percentage financed in equity. The present value (PV) of the interest costs for each instrument is given by:

$$\begin{aligned} \text{PV of interest cost} &= r_D(q_D)(K_F) \sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t} + \\ &+ r_S(q_S)(K_F) \sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t} = [r_D(q_D) + r_S(q_S)][K_F \\ &\sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t}] \quad \dots (4) \end{aligned}$$

where: q_D = the percent of the system's capital cost financed by debt.

q_S = the percent of the system's capital cost financed by issuing equity.

Interest paid on debt is a deductible expense for corporate income taxes. The effective cost of debt interest is therefore reduced by the factor $1 - T_c$ where T_c is the corporate income tax rate. The debt principal must also be repaid at the end of the financing period. The funds raised by issuing stocks do not have to be repaid in a lump sum at the end of the project. However, in order to sell the stock the buyer must be expecting a positive return. The present value of the principal repayment plus the funds that will continue to be paid as dividends can be approximated by the expression:

$$\frac{K_F}{(1+c_k)^{(m-\alpha)+n}}$$

The present value of the total cost of capital to the firm can be expressed as:

$$\begin{aligned} C_c &= [(1-T_c)(q_D)(r_D) + r_S(q_S)][K_F \sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t}] + \\ &+ \frac{K_F}{(1+c_k)^{(m-\alpha)+n}} \quad \dots (5) \end{aligned}$$

2.1.1.2 Mortgage debt. If the owner of the energy system is not a corporation, his financing alternatives are reduced to buying debt or saving in advance. For this analysis we will consider the debt alternative only. We also assume this debt would probably be in the form of a mortgage. The cost of a mortgage

includes interest expense and the repayment of the principal. These two costs must be separated because only the interest can be used as a tax deduction.

Repayment of a mortgage is accomplished by periodic payments of a specific amount for a predetermined number of time periods. Each payment consists of interest due on the remaining principal and repayment of a portion of the principal. Let X equal the amount of the periodic payment. Let K_p equal the amount originally financed. The percentage of the payment which is interest is I_t and the remainder represents a principal payment (P_t). Therefore, I_t plus P_t equals 1.

The first payment will be almost all interest ($I_0 \approx 1$). The percentage of X which is interest in the second payment is given by:

$$I_1 = \frac{rK_p}{X}$$

where: r = rate of interest on the mortgage.

$$\text{similarly, } I_2 = \frac{r(K_p - P_1X)}{X}$$

$$I_3 = \frac{r(K_p - P_1X - P_2X)}{X}$$

Therefore, in general:

$$I_t = \frac{r \left[K_p - \sum_{j=1}^t (P_{j-1}X) \right]}{X} \quad \dots (6)$$

where: $(K_p - X \sum_{j=1}^t P_{j-1})$ represents the remaining principal at time t .

Substituting $(1 - I_t)$ for P_t in equation (6) yields:

$$I_t = \frac{r}{X} (K_p - X \sum_{j=1}^t (1 - I_{j-1}))$$

$$I_t = \frac{rK_p}{X} - r \sum_{j=1}^t (1 - I_{j-1}) \quad \dots (7)$$

The standard method for determining the size of a mortgage payment is given by the capital recovery formula.* Algebraically;

$$\frac{r}{1 - (1+r)^{-(N+\alpha)}} = \text{capital recovery}$$

factor

where: $(N + \alpha)$ = the length of the mortgage

In other words, the expression represents the decimal fraction of the initial mortgaged amount which, paid in equal amounts, will repay interest and principal over the life of the mortgage $((N + \alpha)$ years). Therefore, we can redefine X as:

$$X = \frac{K_p r}{1 - (1+r)^{-(N+\alpha)}}$$

substituting in equation (7) yields

$$I_t = 1 - (1+r)^{-(N+\alpha)} - r \sum_{j=1}^t (1 - I_{j-1}) \quad \dots (8)$$

The present value (PV) of equation (8) is expressed as:

$$\bar{I}_t = \text{PV of } I_t = \sum_{t=m-\alpha}^{m+n} [1 - (1+r)^{-(N+\alpha)} - r \sum_{j=m-\alpha}^{m+n} (1 - I_{j-1})] (1+c_k)^{-t} \quad \dots (9)$$

Since mortgage interest is a deductible expense for income tax purposes, the effective cost of the interest payment (as a decimal fraction of X) can be expressed as:

$$[1 - T_I] \bar{I}_t \quad \dots (10)$$

where: T_I is the individual income tax rate.

Multiplying equation (10) by X (the amount of the payment) expresses the effective interest cost in present dollars.

$$\text{Effective PV Cost of Interest} = [1 - T_I] \bar{I}_t X \quad \dots (11)$$

The cost of the principal each period can be expressed as:

$$P_t X = (1 - \bar{I}_t) X \quad \dots (12)$$

Combining equations (11) and (12) yields the total cost of buying a mortgage.

$$\begin{aligned} \text{(PV) of total cost} &= [1 - T_I] \bar{I}_t X + (1 - \bar{I}_t) X \\ &= X [\bar{I}_t (1 - T_I) + (1 - \bar{I}_t)] \\ &= X [\bar{I}_t - T_I \bar{I}_t + 1 - \bar{I}_t] \end{aligned}$$

* The Engineers Companion, Mott Souders, John Wiley and Sons, 1966, p. 270.

$$(PV) \text{ of Total Cost} = X [1 - T_c] \quad (13)$$

Equation (13) is then entered into the cost function if the system is privately owned and financed with a mortgage. If it is corporate owned, equation (3) should enter the cost equation.

2.2 FOSSIL FUEL COSTS

The present value of future fuel expenses is handled using a straight forward present value approach. The quantity of fossil fuel needed is determined by the technical requirements of the system and its geographical location. The price is forecast for each period. The present value of the total cost of fossil fuel (C_p) is expressed as:

$$C_p = \sum_{t=m}^{m+n} \frac{C_t}{(1+c_k)^t} \quad (14)$$

where: C_t = the total cost (quantity times price) of fossil fuel used in the period t .

Fuel costs are considered an operating expense for income tax calculations. This is a federal subsidy to fossil fuel consumption since the tax reduces the effective cost by a factor of $[1 - T_c]$. Equation (14) can then be rewritten as:

$$C_p = [1 - T_c] \sum_{t=m}^{m+n} \frac{C_t}{(1+c_k)^t} \quad (15)$$

Forecasting the price of fossil fuel in each of the n periods is the crucial, as well as the most difficult, component of this cost estimation. Price forecasts differ widely. Therefore, different estimates should be entered into the model and tested for cost sensitivity. In the case of on-site solar energy systems fuel costs refer to fossil fuels used in both electricity generation and space conditioning energy.

2.3 MAINTENANCE AND OPERATION COSTS

Maintenance and operating costs, excluding fuel expenses, are estimated using the same approach as fuel costs. The present value of maintenance and operating costs (C_{o+m}) is given by:

$$C_{o+m} = \sum_{t=m}^{m+n} \frac{C_o^t + C_m^t}{(1+c_k)^t} \quad (16)$$

where: C_o^t = the total operating cost incurred in the period t . (The superscript t does not represent a power function)

C_m^t = the total maintenance cost incurred in time period t .

These operating costs are also tax deductible expenses. The effective cost of maintenance and operation is given by:

$$[1 - T_c] C_{o+m} = [1 - T_c] \sum_{t=m}^{m+n} \frac{C_o^t + C_m^t}{(1+c_k)^t} \quad (17)$$

2.4 PROPERTY TAXES

To this point, the analysis has only considered the effect of the corporate and individual income tax on costs. Some energy systems may result in higher property taxes. It will be assumed that property tax is a relatively small expense for a corporation. Therefore, only the effect of property tax on individually owned systems will be considered.

The property tax pertinent to this study is the additional tax paid as a direct result of adding an energy system. Usually, property taxes are compiled on the basis of assessed valuation. The assessed value is some fraction of the market value of the property. The actual tax is then calculated as a percentage of the assessed valuation. The wide variation in property taxes was demonstrated in a recent study prepared for the National Commission on Urban Problems.* According to the study, approximately 70,000 local government units are authorized to levy property taxes. In addition, each state (and the District of Columbia) has a different legal system. As a result, according to the author, "there are really 70,000 or so different property taxes in the United States, grouped into 51 systems with common legal settings."*

Despite the complicated nature of the property tax system, some averages of the tax rates and assessed value ratios have been compiled. If the exact location of the system is known, the appropriate local tax rate can be used.

The market value of an energy system can be approximated by the book value of the capital cost. In this analysis it is approximated by K . The present value of the additional property tax can then be expressed as:

$$T_p = \sum_{t=m}^{m+n} \frac{(p)(a)(K)}{(1+c_k)^t} \quad (18)$$

where: T_p = the present value of property tax attributable to a new energy system

a = assessed value expressed as a percent of market value

p = property tax rate

K = book value of the capital goods, (an approximation of the system's market value)

* Impact of the Property Tax by Dick Netzer for the National Commission on Urban Problems, 1968, p. 5.

Since property taxes are a deductible expense for individual income taxes, the effective cost is reduced $[1 - T_I]$ where T_I is the individual income tax rate. Equation (18) is then expressed as:

$$[1 - T_I]T_P = (1 - T_I) \sum_{t=m}^{m+n} \frac{(p)(a)K}{(1+c_k)^t} \quad \dots (19)$$

2.5 THE TAX BENEFITS OF DEPRECIATION

The depreciation of capital assets reduces the effective cost of an energy system because it lowers the corporation's income tax. The first step in calculating the cost reduction is to determine the depreciation each time period. The two methods for calculating depreciation which will be considered are straight line and double declining balance.

For both methods, it will be assumed that at the end of $m+n$ years the energy system does not have enough salvage value to be worth considering. Let D_t equal the amount of depreciation deducted in period t . The present value of the depreciation, using a straight line (SL) method is given by:

$$\frac{K}{n} \sum_{t=m}^{m+n} \frac{1}{(1+c_k)^t}$$

Incorporating the tax benefit feature of the depreciation this column yields:

$$\text{Tax Benefits of SL Depreciation} = -T_c \frac{K}{n} \sum_{t=m}^{m+n} \frac{1}{(1+c_k)^t} \quad \dots (20)$$

The expression is negative because it reduces the total cost of the energy system.

The double declining balance method is given by the following general form:*

$$D_t = K \left(\frac{2}{n} \right) \left(1 - \frac{2}{n} \right)^{(t-1)}$$

However, most corporations only use a double declining balance (DDB) until the time period when a straight line method would yield a larger amount to depreciate. This process can be expressed by:**

* The Capital Budgeting Decision by Harold Bierman and Seymour Smidt, MacMillan Company, New York, 3rd Edition, p. 246.

** "Public Utility Investment Analysis" by J. Hasb, National Technical Information Service, Department of Commerce, January 1971.

*** 1974 Federal Tax Course, Prentice-Hall, Englewood Cliffs, New Jersey, 1973, p. 2050.

$$D_t = \begin{cases} K \left(\frac{2}{n} \right) \left(1 - \frac{2}{n} \right)^{t-1} & \text{if } t < \left(\frac{n}{2} \right) + 1 \\ K \frac{\left(1 - \frac{2}{n} \right)^{t_c-1}}{n + 1 - t_c} & \text{if } t \geq \left(\frac{n}{2} \right) + 1 \end{cases}$$

where: t_c is the first t greater than or equal to $\frac{n}{2} + 1$.

The present value of this method is then:

$$\sum_{t=m}^{m+n} \frac{D_t}{(1+c_k)^t}$$

Incorporating the tax effect yields the final equation:

Tax benefits of DDB and SL Depreciation =

$$-T_c \sum_{t=m}^{m+n} \frac{D_t}{(1+c_k)^t} \quad \dots (21)$$

2.5 THE INVESTMENT TAX CREDIT

In addition to depreciation allowances, the cost of an investment to a corporation can also be reduced by utilizing investment tax credits. An investment tax credit allows a certain percentage of new investment to be deducted from the firm's tax liability. The credit can only be claimed in one time period and it does not reduce the basis for depreciation.

The law also states that the credit cannot be more than the first \$25,000 of tax liability plus one-half of the liability in excess of \$25,000.*** For the purpose of this analysis, however, we will assume the tax credit does not exceed the allowance maximum. Given this assumption, the cost reduction attributable to an investment tax credit can be expressed as:

$$- (\beta) \cdot (K)$$

where: β = the investment tax credit (expressed as a decimal fraction)

We will assume the tax credit is claimed when construction of the project is started (time $m-\alpha$). The present values of the credit is given by:

$$I_t = -\beta(K)(1+c_k)^{-(m-\alpha)} \quad \dots (22)$$

3. SUMMARY

The components of the total cost function applicable to any energy system will depend on the ownership of the system. The function can be divided into two general cases. The first is corporate owned, with minor modifications for publicly owned corporations, and the second is privately owned. The corporate owned system finances using equity and debt, uses depreciation to reduce cost and is assumed to ignore the effect of property tax. The corporate cost curve is the summation of equations (5), (15), (17), (21), and (22).

Algebraically,

$$\begin{aligned} \text{P.V. of Total Cost} &= \left\{ [(1-T_c)q_D r_D + r_s q_s] \right. \\ &\quad \left. \text{Corporate} \right\} + \left\{ \left[K_F \sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t} \right] + \frac{K_F}{(1+c_k)^{(m-\alpha)+n}} \right\} + \left\{ [1-T_c] \right. \\ &\quad \left. \sum_{t=m}^{m+n} \frac{C_t}{(1+c_k)^t} \right\} + [1-T_c] \sum_{t=m}^{m+n} \frac{C_o^t + C_m^t}{(1+c_k)^t} - T_c \sum_{t=m}^{m+n} \\ &\quad \frac{D_t}{(1+c_k)^t} - \frac{\beta(K)}{(1+c_k)^{m-\alpha}} \quad \dots (23) \end{aligned}$$

The individually owned energy system is financed with mortgage debt, incurs additional property tax, and does not receive the tax benefits of depreciating the asset. The individually owned system is represented by the summation of equations (13), (14), (16), (19), and (22).

Algebraically:

$$\begin{aligned} \text{P.V. of Total Cost} &= X [1 - T_I \bar{I}_t] + \\ &\quad \text{Individual} \\ &\quad \left\{ \sum_{t=m}^{m+n} \frac{C_p^t}{(1+c_k)^t} \right\} + \left\{ \sum_{t=m}^{m+n} \frac{C_o^t + C_m^t}{(1+c_k)^t} \right\} + [1 - T_I] \\ &\quad \sum_{t=m}^{m+n} \frac{p(a)K}{(1+c_k)^t} - \left\{ \frac{\beta(K)}{(1+c_k)^{m-\alpha}} \right\} \quad \dots (24) \end{aligned}$$

Equations (23) and (24) represent the total life-cycle cost of an on-site solar energy system to a corporation and an individual, respectively. As mentioned previously, the equation also offers a convenient method for calculating the life-cycle cost of other types of energy systems.

4. BIOGRAPHIES

Mr. Costello is an energy economist at Midwest Research Institute, Kansas City, Missouri. He specializes in the development and analysis of energy policy.

Recently, he led the socioeconomic analysis tasks in a major study of the impacts of commercial development of solar energy for the U.S. Congress.

Mr. Costello received the B.A. in Economics (1972) from the State University of New York where he graduated Magna Cum Laude and the M.A. in Economics (1973) from Ohio State University.

Mr. Bradley is an Associate Engineer at Midwest Research Institute and specializes in the technical and economic analysis of solar energy systems.

He is currently responsible for the technoeconomic analysis phases of MRI's on-going studies of solar electric systems.

Mr. Bradley is a member and former officer of the Kansas City chapter of the Society of Manufacturing Engineers and is a member of the International Solar Energy Society. He received the B.S. in Mechanical Engineering (1968) and the M.B.A. in Finance (1973) from the University of Kansas.

APPENDIX C

DERIVATION OF PEPS COST MODEL

DERIVATION OF PEPS COST MODEL

Equation 23 in Appendix B, which is repeated below, expresses the present value of the total cost to a corporation of owning and operating a solar energy systems. Definitions of all terms used in the following equations are defined in Table I.

$$\begin{aligned}
 \text{P.V. of Total Cost} &= \left\{ [(1-T_c)q_D r_D + r_s q_s] \right. \\
 \text{Corporate} &\quad \left. \left[K_F \sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t} \right] + \frac{K_F}{(1+c_k)^{(m-\alpha)+n}} \right\} + \left\{ [1-T_c] \right. \\
 &\quad \left. \sum_{t=m}^{m+n} \frac{C_t}{(1+c_k)^t} \right\} + [1-T_c] \sum_{t=m}^{m+n} \frac{C_o^t + C_m^t}{(1+c_k)^t} - T_c \sum_{t=m}^{m+n} \\
 &\quad \frac{D_t}{(1+c_k)^t} - \frac{\beta(K)}{(1+c_k)^{m-\alpha}} \quad \dots (23)
 \end{aligned}$$

The remainder of this appendix develops the modification of Equation 23 to express an estimate of the maximum price that an investor-owned utility would pay for a photovoltaic electric power system (PEPS).

If the credit for displacement of coal capacity, as well as the cost of insurance, and state and local taxes are included, Equation 23 may be stated in simple, after-tax, present value terms as:

$$\begin{aligned}
\boxed{\text{Total Cost}} &= \boxed{\text{Financing Costs}} + \boxed{\text{Cost of Fuel}} \\
&+ \boxed{\text{Operating and Maintenance Costs on PEPS}} - \boxed{\text{The Tax Benefits of Depreciation}} \\
&- \boxed{\text{Investment Tax Credit}} + \boxed{\text{Cost of Insurance}} + \boxed{\text{Cost of Gas Turbine Capacity}} \\
&- \boxed{\text{Cost of Coal Capacity}} + \boxed{\text{Cost of State and Local Taxes}}
\end{aligned}$$

By setting total cost equal to zero (the point where the utility would be indifferent to PEPS), this equation may be rearranged as follows:

$$\begin{aligned}
\boxed{\text{Financing Costs}} &= \boxed{\text{Fuel Savings}} - \boxed{\text{Operating and Maintenance Costs}} \\
&+ \boxed{\text{Tax Benefits of Depreciation}} + \boxed{\text{Investment Tax Credit}} \\
&- \boxed{\text{Cost of Insurance}} - \boxed{\text{Cost of State and Local Taxes}} \\
&- \boxed{\text{Cost of Gas Turbine Capacity}} + \boxed{\text{Cost of Coal Capacity}}
\end{aligned}$$

Using the terms contained in Equation 23 of Appendix B, the above expression can be written as:

$$\begin{aligned}
&\left\{ [(1-T_c)q_D r_D + q_S r_S] \left[K_f \sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t} \right] + \frac{K_f}{(1+c_k)^{m-\alpha+n}} \right\} = \\
&[1 - T_c] \left\{ \sum_{t=m}^{m+n} \frac{C_t}{(1+c_k)^t} \right\} - [1 - T_c] \left\{ \sum_{t=m}^{m+n} \frac{C_o^t + C_m^t}{(1+c_k)^t} \right\} \\
&+ T_c \sum_{t=m}^{m+n} \frac{D_t + (E_t - F_t)}{(1+c_k)^t} + \frac{\beta(K+C_G-C_C)}{(1+c_k)^{m-\alpha}} - (K+C_G-C_C)(1-T_c) \left\{ \sum_{t=m}^{m+n} \frac{1}{(1+c_k)^t} + \sum_{t=m}^{m+n} \frac{(p)(a)}{(1+c_k)^t} \right\} - C_G + C_C
\end{aligned}$$

Substituting from Equation 2 from Appendix B, the above equation may be solved for K, the nominal value of all construction expenditures.

$$K_F = \frac{K}{\alpha} \sum_{t=m-\alpha}^m \frac{1}{(1+c_k)^t} \quad (2)$$

This is the maximum justifiable investment in a PEPS and is directly comparable to the engineering cost estimate to be discussed throughout this report.

If we define the following new variables:

$$S_1 = \sum_{t=m-\alpha}^m \frac{1}{(1+c_k)^t}$$

$$S_4 = \sum_{t=m}^{m+n} \frac{1}{(1+c_k)^t}$$

$$S_2 = \sum_{t=m-\alpha}^{m+n} \frac{1}{(1+c_k)^t}$$

$$S_5 = \sum_{t=m}^{m+n} \frac{c_t}{(1+c_k)^t}$$

$$S_3 = \sum_{t=m}^{m+n} \frac{dt}{(1+c_k)^t}$$

$$S_6 = \sum_{t=m}^{m+n} \frac{C_0^t + C_m^t}{(1+c_k)^t}$$

$$S_7 = \sum_{t=m}^{m+n} \frac{(E_t - F_t)}{(1+c_k)^t}$$

the equation may be simplified and solved for K, the maximum acceptable price of PEPS.

$$\begin{aligned}
& \frac{K}{\alpha} S_1 \left\{ [(1-T_c)q_D r_D + q_S r_S] \left[S_2 + \frac{1}{(1+c_k)^{m-\alpha+n}} \right] \right\} \\
& - K T_c S_3 - \frac{K\beta}{(1+c_k)^{m-\alpha}} + K(1-T_c) \left\{ S_4 [i + (P.a)] \right\} \\
& = [1-T_c] \{ S_5 - S_6 \} + T_c S_7 + \beta \frac{(C_G - C_C)}{(1+c_k)^{m-\alpha}} \\
& - (C_G - C_C)(1-T_c) \left\{ S_4 [i + (P.a)] \right\} - C_G + C_C
\end{aligned}$$

Solving for K yields:

$$K = \frac{(1-T_c)(S_5 - S_6) + T_c S_7 + \beta \frac{(C_G - C_C)}{(1+c_k)^{m-\alpha}} - (C_G - C_C)(1-T_c) \left\{ S_4 [i + (P.a)] \right\}}{\frac{1}{\alpha} S_1 \left\{ [(1-T_c)q_D r_D + q_S r_S] \left[S_2 + \frac{1}{(1+c_k)^{m-\alpha+n}} \right] \right\} - T_c S_3 - \frac{\beta}{(1+c_k)^{m-\alpha}} + (1-T_c) \left\{ S_4 [i + P.a] \right\}}$$

The above equation for the maximum allowable price of PEPS may be expressed in an after-tax manner which has some intuitive appeal:

$$K = \frac{\text{fuel savings} - \text{operating and maintenance costs} + \text{net credit capacity displaced}}{\text{financing cost} - \text{tax benefit of depreciation} - \text{tax credit} + \text{cost of insurance} + \text{cost of state and local taxes}}$$

From the above statement, it can be seen that the maximum justifiable investment in a PEPS is equal to the sum of the net capacity credit and the after-tax value of fuel saving, less after-tax operating and maintenance costs associated with the PEPS. This net savings is adjusted on a per-dollar-of-investment basis for the after-tax cost of financing, insurance and state and local taxes, plus the tax benefits of depreciation and the investment tax credit.

For the sake of convenience, the above relationship was computerized and is shown in Appendix D.

TABLE I

T_c = Corporate income tax rate

q_D = Percent of project financed with debt

r_D = Interest rate or debt

q_s = Percent of project financed with equity

r_s = Rate of return required by stockholders

K_F = Dollar amount that will have to be financed

c_k = Weighted cost of capital used to discount future cash flows

C_t = Cost of fuel consumed in year t (\$/year)

C_o^t = Cost of operating system in year t (\$/year)

C_m^t = Cost of maintenance in year t (\$/year)

D_t = Amount of depreciation of solar equipment in year t (\$/year)

β = Investment tax credit rate

i = Annual insurance cost expressed as a fraction of installed
system cost

a = Assessed value as a percent of market value (for property tax
calculation)

P = Property tax rate

E_t = Depreciation on gas turbine generating capacity in year t

F_t = Depreciation on coal fired generating capacity in year t

C_G = Installed cost of gas turbine generating capacity (\$/kw)

C_C = Installed cost of coal-fired generating capacity (\$/kw)

n = Useful life of PEPS

m = Longest construction time of any of the PEPS designs to be considered

α = Construction time of PEPS design under consideration ($\alpha \leq m$).

APPENDIX D

PEPS ECONOMIC ANALYSIS MODEL

PEPS ECONOMIC ANALYSIS MODEL

The following pages represent the computer software used in the economic analysis. The listing contains numerous comment cards explaining the logic of the routine and also defining the significant variables used in the program. Figure 1 is a general flow chart of the model, which may be helpful in appreciating the scope of the model. A more detailed discussion of the economic analysis can be found in Section 9.2.

Also included in this appendix is a sample of the output for the base case. The first page of output lists economic input assumptions, while the next two pages represent the results of the economic analysis for each capacity factor. The final page gives a summary of the two previous pages. The results of exercising the model are discussed fully in Sections 9.2 and 9.7.

* Items (3) thru (7) are expressed in dollars per dollar of investment

Figure 1 - General Flowchart of PEPS Economic Analysis Model

PROGRAM MAIN(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)

REAL NPVDIF
INTEGER CONPEPS
DIMENSION FC(100),CAPFAC(6),PVFC(100),COM(100),
PVFCAT(100),PAYMT(100),PNTRST(100),TOT(100),CKFNPV(100),
DEPN(100),DEP(100),TCINV(100),PERTAX(100),PVTOTC(6,100),
.INDEX(20),PVFCRT(100)
.DIFF(100),ADJFAC(100)
.SEQUIP(100)
DIMENSION CMILLS(100)
DIMENSION PNIX(2),CLVD(2),CITY(2)
DATA PNIX(1)/7HPHOENIX/,PNIX(2)/7H /,
CLVD(1)/7HCLEVELA/,CLVD(2)/7HND /

VARIABLES

CONPEPS-CONSTRUCTION TIME FOR PEPS (YEARS)
CONGAS-CONSTRUCTION TIME FOR GAS TURBINE (YEARS)
RATED-REAL LONG TERM INTEREST RATE
RATES-REAL RATE OF RETURN ON STOCK
PEREQF-PERCENT OF ORGANIZATION FINANCED BY STOCK
PEREQP-PERCENT OF SYSTEM FINANCED BY STOCK
TAXCOR-CORPORATE FEDERAL INCOME TAX RATE
TCINVR-INVESTMENT TAX CREDIT RATE
DEPR-DEPRECIATION (1.0-STRAIGHT LINE, 2.0-DOUBLE
DECLINING BALANCE)
PINS-INSURANCE RATE
TAXPEF-EFFECTIVE PERSONAL PROPERTY TAX RATE
TAXIND-INDIVIDUAL FEDERAL INCOME TAX RATE
TAXCP-AVERAGE STATE AND LOCAL TAX RATE ON CORPORATE ASSETS
TAXPU-AVERAGE STATE AND LOCAL TAX RATE OF PAYMENT
IN LIEU OF TAXES FOR PUBLIC UTILITIES
FCR-LEVELIZED FIXED CHARGE RATE
CRF-CAPITAL RECOVERY FACTOR
RATEW-WEIGHTED COST OF CAPITAL
CMILLS-LEVELIZED FUEL COST IN MILLS/KWH
CAPFAC-PEPS PLANT CAPACITY FACTOR
DCOAL-NOMINAL COST OF EQUIPMENT AND LABOR FOR COAL CAPACITY
DGAS-SAME FOR GAS TURBINE (NOTE: IN BOTH DCOAL AND DGAS,
COSTS INCLUDE ESCALATION AND NOT INTEREST DURING CONSTRUCTION)
PVFC,PVFCRT-BEFORE TAX PRESENT VALUE OF FUEL DISPLACED BY PEPS
PVCAT-AFTER TAX VALUE OF FUEL DISPLACED BY PEPS
COM-PRESENT VALUE OF AFTER TAX COST OF O+M ON PEPS
TOT-MORTGAGE COST (\$/\$ OF INVESTMENT)
CKFNPV-FINANCING COST (\$/\$ OF INVESTMENT)
DEPN-DEPRECIATION (\$/\$ OF INVESTMENT)
TCINV-INVESTMENT TAX CREDIT (\$/\$ OF INVESTMENT)
ADJFAC-ADJUSTMENT FACTOR FOR DEPRECIATION, INVESTMENT TAX CREDIT
.MORTGAGE,FINANCING,AND PERSONAL PROPERTY TAX
PVGAS-PRESENT VALUE OF LIFE CYCLE COST FOR GAS TURBINE (\$/KW)
PVCOAL-PRESENT VALUE OF LIFE CYCLE COST FOR COAL CAPACITY (\$/KW)
SEQUIP-ADDITIONAL INVESTMENT FACTOR DUE TO DISPLACEMENT

```

C      OF COAL CAPACITY WITH GAS TURBINE
C      PVTOTC-MAXIMUM INVESTMENT PER KW FOR PEPS
C
C      THE PROGRAM STARTS HERE
C
1000 CONTINUE
C
C      READ IN CASE NUMBER FOR EACH SET OF DATA
C
9999 FORMAT(I10)
    READ(5,9999) NCASE
C
C      READ IN ECONOMIC PARAMETERS
C
    READ(5,50) OWNER,RATED,RATES,PEREQF,PEREQP,
+    TAXCOR,TCINVR,DEPR,TAXPEF,TAXIND,TAXCP,TAXPU,PINS
50 FORMAT(13F6.2)
    IF(OWNER.EQ.0.0) STOP
    PERLTD=1.0-PEREQF
    RATEW=(PEREQF*RATES)+((1.0-PEREQF)*RATED)
    IF(OWNER.EQ.1) OTAXES=TAXCP
    IF(OWNER.EQ.2) OTAXES=TAXPU
    IF(OWNER.EQ.3) OTAXES=TAXPEF
    LIFE=30.
C
C      CALCULATION OF CAPITAL RECOVERY FACTOR
C      AND LEVELIZED FIXED CHARGE RATE
C
    CRF=RATEW*(1.0+RATEW)**LIFE/((1.0+RATEW)**LIFE-1.0)
    FCR=(1.0/(1.0-TAXCOR))*CRF+RATED*PERLTD-TAXCOR/
+    ((1.0-TAXCOR)*LIFE)+OTAXES+PINS
C
C      PRINT ECONOMIC INPUT ASSUMPTIONS
C
    WRITE(6,3002)
3002 FORMAT(1H1,/,20X,16HINPUT PARAMETERS,/,19X,18(1H-),/)
    WRITE(6,1120) NCASE
1120 FORMAT(17X,33HNOTE: ALL RATES ARE IN REAL TERMS,
+    /,17X,33HAND THUS DO NOT INCLUDE INFLATION,/,
+    40X,6HCASE =,I10,/)
    IF(OWNER.EQ.1.0) GO TO 3100
    IF(OWNER.EQ.2.0) GO TO 3101
    IF(OWNER.EQ.3.0) GO TO 3102
3100 WRITE(6,3010)
    GO TO 3103
3101 WRITE(6,3011)
    GO TO 3103
3102 WRITE(6,3012)
3010 FORMAT(5X,25HSYSTEM IS CORPORATE OWNED,/)
3011 FORMAT(5X,24HSYSTEM IS PUBLICLY OWNED,/)
3012 FORMAT(5X,25HSYSTEM IS PRIVATELY OWNED,/)
3103 CONTINUE
    WRITE(6,3013) RATED,RATES
3013 FORMAT(5X,25HLONG TERM INTEREST RATE =,F5.2,10X,15HRATE OF RETURN

```

```

+      10HON STOCK =,F5.2,/)
      WRITE(6,3014)PEREQF
3014  FORMAT(5X,43HPORTION OF ORGANIZATION FINANCED BY STOCK =,F5.2,/)
      WRITE(6,3015)PEREQP
3015  FORMAT(5X,42HPORTION OF SYSTEM COST FINANCED BY STOCK =,F5.2,/)
      WRITE(6,3016)RATEW
3016  FORMAT(5X,42HWEIGHTED COST OF CAPITAL (DISCOUNT RATE) =,F7.4,/)
      IF (DEPR.EQ.1.0) WRITE(6,3017)
      IF (DEPR.EQ.2.0) WRITE(6,3018)
3017  FORMAT(5X,39HMETHOD OF DEPRECIATION IS STRAIGHT LINE,/)
3018  FORMAT(5X,50HMETHOD OF DEPRECIATION IS DOUBLE-DECLINING BALANCE,/)
      WRITE(6,3323)FCR,CRF
3323  FORMAT(5X,19HFIXED CHARGE RATE =,F10.4,
+      //,5X,25HCAPITAL RECOVERY FACTOR =,F10.4)
      XPINS=PTNS*100
      WRITE(6,3030)XPINS
3030  FORMAT(/,5X,19HINSURANCE PREMIUM =,F10.4,3X,
+      21HPERCENT OF INVESTMENT)
      WRITE(6,3019)
3019  FORMAT(/,13X,5HTAXES,/)
      IF(OWNER.EQ.1.0)GO TO 3050
      IF(OWNER.EQ.2.0)GO TO 3060
      IF(OWNER.EQ.3.0)GO TO 3070
3050  WRITE(6,3020)TAXCOR
3020  FORMAT(5X,27HCORPORATE INCOME TAX RATE =,F5.2,/)
      WRITE(6,3021)TCINVR
3021  FORMAT(5X,23HINVESTMENT TAX CREDIT =,F5.2,/)
      WRITE(6,3055)TAXCP
3055  FORMAT(5X,36HEFFECTIVE CORPORATE ASSET TAX RATE =,F7.4,/)
      GO TO 3080
3060  WRITE(6,3056)TAXPU
3056  FORMAT(5X,41HPUBLIC UTILITY PAYMENT IN LIEU OF TAXES =,F6.3,/)
      GO TO 3080
3070  WRITE(6,3022)TAXIND
3022  FORMAT(5X,28HINDIVIDUAL INCOME TAX RATE =,F6.3,/)
      WRITE(6,3023)TAXPEF
3023  FORMAT(5X,38HEFFECTIVE PERSONAL PROPERTY TAX RATE =,F6.3)
3080  I=1

```

```

C
C      CONSTRUCTION TIME FOR THE PEPS IS ASSUMED TO BE 3 YEARS
C

```

```

      CONPEPS=3

```

```

C
C      READ IN TEN SAMPLE LEVELIZED FUEL COSTS (MILLS/KWH)
C

```

```

      READ(5,51) (CMILLS(I), I=1,10)
51  FORMAT (10F7.2)

```

```

C
C      SET TWO VALUES FOR CAPACITY FACTOR
C

```

```

      CAPFAC(1)=0.194
      CAPFAC(2)=0.308

```

```

C      READ IN CONSTRUCTION TIMES FOR COAL-FIRED CAPACITY
C      AND GAS TURBINES, AND ALSO NOMINAL EQUIPMENT AND LABOR
C      COSTS FOR BOTH
C
C      READ (5,2005) CONCOAL, CONGAS, DCOAL, DGAS
C
C      PRINT ASSUMPTIONS FOR COAL-FIRED CAPACITY AND GAS TURBINE
C
C      KONGAS=CONGAS
C      KONCOAL=CONCOAL
C      2005 FORMAT(4F10.2)
C      WRITE(6,2051) CONCOAL, DCOAL, CONGAS, DGAS
C      2051 FORMAT(30X, *CONSTRUCTION NOMINAL COST*, /, 30X, 12(1H-),
C      +      3X, 12(1H-), /, 10X, *COAL-FIRED CAPACITY*, 2X, F3.1, * YEARS*,
C      +      4X, 1H$, F7.2, */KW*, //, 15X, *GAS TURBINE*, 5X, F3.1, * YEARS*,
C      +      4X, 1H$, F7.2, */KW*, /)
C
C      LIFE CYCLE COST ROUTINE
C
C      THE TWO LOOPS WILL REPRESENT THE FOLLOWING*
C      NT, THE INNER LOOP, REPRESENTS THE LEVELIZED FUEL COST (MILLS/KWH)
C      KF, THE OUTER LOOP, WILL REPRESENT THE
C      PLANT CAPACITY FACTOR, EITHER 0.129 REPRESENTING CLEVELAND
C      OR 0.205 REPRESENTING PHOENIX CAPACITY FACTORS
C
C      DO 1050 KF=1,2
C
C      DO 1100 NT=1,10
C
C      FUEL COST AND OPERATION AND MAINTENANCE CALCULATION
C
C      LIM2=CONPEPS+LIFE
C      COM(NT)=0.0
C      PVFC(NT)=0.0
C      PVFC(NT)=(CMILLS(NT)*8760.*CAPFAC(KF)*.001)/CRF
C      DO 13 N=CONPEPS,LIM2
C      COM(NT)=COM(NT)+5.0/(1.0+RATEW)**N
C      13 CONTINUE
C      CUM(NT)=COM(NT)*(1.0-TAXCOR)
C      PVFCAT(NT)=PVFC(NT)*(1.0-TAXCOR)
C
C      PVFCBT(NT)=PVFCAT(NT)/(1.0-TAXCOR)
C
C      LIM1=CONPEPS
C
C      FINANCE DECISION
C
C      IF (OWNER.LT.3.0) GO TO 41
C
C      MORTGAGE
C
C      PAYMT(NT)=RATED/(1.0-(1.0/(1.0+RATEW)**(LIFE+CONPEPS

```

```

+      )))
      PNTRST(LIM1)=1.0
      TOT(NT)=PAYMT(NT)*(1.0-TAXIND)/(1.0+RATEW)**(CONPEPS )
      SUM=0.0
      LIM2=CONPEPS+LIFE
      LIM3=LIM1+1
      DO 10 N=LIM3,LIM2
      PNTRST(N)=1.0-(1.0/(1.0+RATED)**(LIFE+CONPEPS ))-RATED*SUM
      SUM=SUM+(1.0-PNTRST(N))
      TOT(NT)=TOT(NT)+(PNTRST(N)*PAYMT(NT)*(1.0-TAXIND)+(1.0-PNTRST(NT))
+      *PAYMT(NT))/(1.0+RATEW)**N
10  CONTINUE
      GO TO 42
41  TOT(NT)=0.0
      SUM=0.0

```

```

C
C      (STOCK AND BOND CALCULATION)
C

```

```

      LIM2=CONPEPS+LIFE
      DO 12 N=1,LIM2
      SUM=SUM+1.0/((1.0+RATEW)**N)
12  CONTINUE
      CKFNPV(NT)=(((1.0-TAXCOR)*(1.0-PEREQP)*RATED+RATES*PEREQP)
+      *SUM)+1.0/((1.0+RATEW)**(CONPEPS+LIFE))
42  CONTINUE

```

```

C
C
C      DEPRECIATION DECISION)
C

```

```

      IF(DEPR.EQ.2.0)GO TO 48

```

```

C
C      STRAIGHT LINE
C

```

```

      SUM=0.0
      DO 61 N=CONPEPS,LIM2
      SUM=SUM+1.0/((1.0+RATEW)**N)
61  CONTINUE
      DEPN(NT)=SUM*TAXCOR/LIFE
      GO TO 49
48  CONTINUE

```

```

C
C      DOUBLE DECLINING
C

```

```

      DDSUM=0.0
      ITC=(LIFE+1.0)/2.0+1.0
      LIM4=CONPEPS+ITC
      LIM4A=LIM4-1
      DO 21 N=CONPEPS,LIM4A
      DEP(N)=((2.0/LIFE)*(1.0-(2.0/LIFE)**(N-CONPEPS)))/
+      (1.0+RATEW)**N
      DDSUM=DDSUM+DEP(N)
21  CONTINUE
      DO 27 N=LIM4,LIFE
      DEP(N)=(((1.0-2.0/LIFE)**(ITC-1.0))/(LIFE+1.0-ITC))/(1.0+

```

```

+ RATEW)**N
DDSUM=DDSUM+DEP(N)
27 CONTINUE
DEPN(NT)=TAXCOR*DDSUM
49 CONTINUE

C
C INVESTMENT TAX CREDIT
C
TCINV(NT)=(TCINVR)/(1.0+RATEW)**CONPEPS

C
C PROPERTY TAX
C
SUM=0.0
DO 38 N=CONPEPS,LIM2
SUM=SUM+1.0/(1.0+RATEW)**N
38 CONTINUE
PERTAX(NT)=TAXPEF*SUM*(1.0-TAXIND)
IF(OWNER.EQ.1)PERTAX(NT)=TAXCP*SUM*(1.-TAXCOR)
IF(OWNER.EQ.2)PERTAX(NT)=TAXPU*SUM

C
C TOTAL COST
C
DIFF(NT)=PVFCAT(NT)-COM(NT)
FACTR1=0.0
SUM=0.0
DO 247 N=1,CONPEPS
SUM=SUM+1.0/(1.0+RATEW)**N
247 CONTINUE
FACTR1=SUM/CONPEPS
ADJFAC(NT)=1/
(-DEPN(NT)-TCINV(NT)+PERTAX(NT)+TOT(NT)+CKFNPV(NT)*FACTR1)

C
C PRINT ELEMENTS OF ADJUSTMENT FACTOR
C
IF(NT.EQ.1.AND.KF.EQ.1)
+ WRITE(6,2054)DEPN(1),TCINV(1),PERTAX(1),CKFNPV(1)
2054 FORMAT(/
+ ,1X,29HELEMENTS OF ADJUSTMENT FACTOR./
+ ,1X,29H($ PER DOLLAR OF INVESTMENT) ,/,1X,29(1H-),/
+ ,1X,30H TAX BENEFITS OF DEPRECIATION ,1(2X,1H(,F4.2,1H),2X),//
+ ,1X,30H INVESTMENT TAX CREDIT ,1(2X,1H(,F4.2,1H),2X),//
+ ,1X,29H PROPERTY TAX ,1(1H ,F7.2,2X),//
+ ,1X,29HAFTER TAX COST OF FINANCING ,1(1H ,F7.2,2X),
+ 1X)

C
C CALCULATE TOTAL COST DIFFERENCE BETWEEN COAL-FIRED CAPACITY
C AND GAS TURBINES
C
CSUM=0.0
GSUM=0.0
LIMGAS=CONPEPS-KONGAS
DO 2001 N=LIMGAS,CONPEPS
GSUM=GSUM+(1.0+RATEW)**(-N)
2001 CONTINUE
PVGC=GSUM*DGAS/CONGAS

```

```

      ICHK=CONPEPS-KONCOAL
      IF(ICHK.LE.0)GO TO 2004
      DO 2003 N=ICHK,CONPEPS
      CSUM=CSUM+(1.0+RATEW)**(-N)
2003  CONTINUE
      GO TO 2007
2004  KNTMP1=CONCOAL
      DO 2006 N=1,KNTMP1
C
      NN=N-CONPEPS
      CSUM=CSUM+(1.0+RATEW)**(-NN)
2006  CONTINUE
2007  CONTINUE
      PVKC=DCOAL*CSUM/CONCOAL
      PVCOAL=DCOAL*(TOT(NT)+PERTAX(NT)-DEPN(NT)-TCINV(NT))+PVKC
      PVGAS=DGAS*(TOT(NT)+PERTAX(NT)-DEPN(NT)-TCINV(NT))+PVGC
      NPVDIF=PVCOAL-PVGAS
      DO 2025 NX=1.10
2025  SEQUIP(NX)=NPVDIF/FACTR1
      PVTOTC(KF,NT)=DIFF(NT)*ADJFAC(NT)+SEQUIP(NT)
      IF(KF.EQ.1.AND.NT.EQ.1)WRITE(6,2100)
+     CONCOAL,CONGAS,DCOAL,DGAS,PVKC,PVGC,PVCOAL,PVGAS,NPVDIF,SEQUIP(1)
2100  FORMAT(1H1,///,10X,*COAL AND GAS TURBINE EQUIPMENT COSTS*,
+     ///,5X,*CONSTRUCTION TIME - COAL PLANT = *F4.2,
+     ///,5X,*CONSTRUCTION TIME - GAS TURBINES = *,F10.2,
+     ///,5X,*NOMINAL COST - COAL CAPACITY = *,F10.2,
+     ///,5X,*NOMINAL COST - GAS TURBINE = *,F10.2,
+     ///,5X,*PRESENT VALUE OF COAL CAPACITY COST = *,F10.2,
+     ///,5X,*PRESENT VALUE OF GAS TURBINE COST = *,F10.2,
+     ///,5X,*LIFE CYCLE COST - COAL = *,F10.2,
+     ///,5X,*LIFE CYCLE COST - GAS = *,F10.2,
+     ///,5X,*DIFFERENCE ( COAL MINUS GAS ) = *,F10.2,
+     ///,20X,*ADDITIONAL INVESTMENT FACTOR = *,F10.2)
1100  CONTINUE
C
C     WRITE STATEMENTS FOR ECONOMIC ANALYSIS
C     FOR EACH CAPACITY FACTOR, GIVEN LEVELIZED FUEL COST (MILLS/KWH)
C
      DO 486 I=1.10
      INDEX(I)=1970+(5*I)
486  CONTINUE
      WRITE(6,3333)
      DO 5451 I=1.2
      IF(CAPFAC(KF).GT.0.2)CITY(I)=PNIX(I)
5451  IF(CAPFAC(KF).LT.0.2)CITY(I)=CLVD(I)
      WRITE(6,3090)NCASE,CAPFAC(KF),(CITY(I),I=1.2),
+     (CMILLS(I),I=1.10),(PVFCHT(NT),NT=1.10),
+     (PVFCAT(NT),NT=1.10),(COM(NT),NT=1.10),
+     (DIFF(NT),NT=1.10),(ADJFAC(NT),NT=1.10),
+     (SEQUIP(NT),NT=1.10),(PVTOTC(KF,NT),NT=1.10)
3090  FORMAT(///,50X,34HDOLLAR BENEFITS OF PEPS INVESTMENT.
+     ///,51X,31H(PRESENT VALUE IN 1976 DOLLARS),
+     ///,100X,6HCASE =,I10,///
+     ///,100X,17HCAPACITY FACTOR =,F8.3,/,98X,
+     19H(REPRESENTATIVE OF ,2A7,/,

```

```

* 38X,54H VARIABLE PORTION OF OVERALL UTILITY OPERATING COST (*),
/ .55X,21H (LEVELIZED MILLS/KWH), //,
27X,10(6X,F4.1), /, 30X,10(1H,8(1H-),1H ), ///
+ ,1X,29H(1) BEFORE-TAX BENEFITS OF ,10(1H$,F7.2,2X), /
+ ,1X,29H DISPLACED VARIABLE COSTS (*), / 30X,100(1H-), //
+ ,1X,29H(2) AFTER-TAX BENEFITS OF ,10(1H$,F7.2,2X), /
+ ,1X,29H DISPLACED VARIABLE COSTS (*), //
+ ,1X,28H(3) LESS OPERATION AND ,10(2H $,F7.2,1H ), /
+ ,1X,29H MAINTENANCE COSTS OF PEPS ,10(1X,8(1H-),1X), ///
+ ,1X,30H(4) NET BENEFITS OF DISPLACED ,10(1H$,F7.2,2X), /,
+ ,1X,30H VARIABLE COSTS (*) ( (2)-(3) ), /, 30X,100(1H-), /
+ ,1X,29H(5) ADJUSTMENT FACTOR FOR ,10(1H $,F7.2,2X), /
+ ,1X,29H OTHER TAX EFFECTS - $ OF , /,
+ ,1X,29H BENEFIT PER $ OF INVESTMENT, /,
+ ,1X,29H (DETAILED ON PREVIOUS PAGE)
+ //
+ ,1X,29H (6) CREDIT FOR DISPLACEMENT ,10(1H$,F7.2,2X), /
+ ,1X,29H OF COAL CAPACITY BY PEPS , /,
+ ,1X,29H AND GAS TURBINE ($/KW) , ///,
+ ,1X,29H(7) MAXIMUM INVESTMENT ,10(1H$,F7.2,2X),
+ /, 1X,29H PER INSTALLED KW ((4)*(5)+(6)), 2(/, 30X,100(1H-)), //
+ //, 7X,33H(*) VARIABLE PORTION OF OVERALL ,
+ 47H UTILITY OPERATING COSTS IS PRIMARILY FUEL COSTS)
1050 CONTINUE

```

C
C
C
C

OUTPUT STATEMENTS FOR SUMMARY PAGE

```

WRITE(6,3333)
3333 FORMAT(1H1)
WRITE(6,3000) NCASE
3000 FORMAT(///// ,45X,28H SUMMARY OF ECONOMIC ANALYSIS, //, 40X,
+ 58H MAXIMUM INVESTMENT PER INSTALLED KW OF PEPS (1976 DOLLARS)
+ , /, 100X,6H CASE =, I10)
WRITE(6,3024) (CMILLS(I), I=1,10)
3024 FORMAT(///, 38X,45H VARIABLE PORTION OF OVERALL UTILITY OPERATING,
+ 9H COST (*), /, 55X,21H (LEVELIZED MILLS/KWH), //, 1X
+ ,23H CAPACITY FACTOR OF PEPS, 5X,10(6X,F4.1), /, 30X,100(1H-), /)
DO 3201 KAP=1,2
DO 3335 I=1,2
IF(KAP.EQ.2) CITY(I)=PNIX(I)
3335 IF(KAP.EQ.1) CITY(I)=CLVD(I)
3201 WRITE(6,3001) CAPFAC(KAP), (CITY(I), I=1,2), (PVTOTC(KAP,NT), NT=1,10)
3001 FORMAT(5X,F8.3,2H (,2A7,3X,10(1H$,F7.2,2X), /)
WRITE(6,3322)
3322 FORMAT(//, 2(1X,129(1H-), /), ///)
WRITE(6,3334)
3334 FORMAT(///// ,7X,33H(*) VARIABLE PORTION OF OVERALL ,
+ 47H UTILITY OPERATING COSTS IS PRIMARILY FUEL COSTS)
GO TO 1000
END

```


INPUT PARAMETERS

NOTE: ALL RATES ARE IN REAL TERMS
AND THUS DO NOT INCLUDE INFLATION
CASE =

100

SYSTEM IS CORPORATE OWNED

LONG TERM INTEREST RATE = .04 RATE OF RETURN ON STOCK = .06

PORTION OF ORGANIZATION FINANCED BY STOCK = .47

PORTION OF SYSTEM COST FINANCED BY STOCK = .40

WEIGHTED COST OF CAPITAL (DISCOUNT RATE) = .0494

METHOD OF DEPRECIATION IS DOUBLE-DECLINING BALANCE

FIXED CHARGE RATE = .1407

CAPITAL RECOVERY FACTOR = .0646

INSURANCE PREMIUM = .2500 PERCENT OF INVESTMENT

TAXES

CORPORATE INCOME TAX RATE = .48

INVESTMENT TAX CREDIT = .03

EFFECTIVE CORPORATE ASSET TAX RATE = .0235

	CONSTRUCTION	NOMINAL COST
	-----	-----
COAL-FIRED CAPACITY	6.0 YEARS	\$ 413.00/KW
GAS TURBINE	2.0 YEARS	\$ 129.00/KW

ELEMENTS OF ADJUSTMENT FACTOR (\$ PER DOLLAR OF INVESTMENT)

TAX BENEFITS OF DEPRECIATION (.25)

INVESTMENT TAX CREDIT (.03)

PROPERTY TAX .17

AFTER TAX COST OF FINANCING .79

DOLLAR BENEFITS OF PEPS INVESTMENT

(PRESENT VALUE IN 1976 DOLLARS)

CASE = 100

CAPACITY FACTOR = .194
(REPRESENTATIVE OF CLEVELAND)

VARIABLE PORTION OF OVERALL UTILITY OPERATING COST (*) (LEVELIZED MILLS/KWH)

	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
(1) BEFORE-TAX BENEFITS OF DISPLACED VARIABLE COSTS (*)	\$ 131.52	\$ 263.04	\$ 394.56	\$ 526.08	\$ 657.60	\$ 789.13	\$ 920.65	\$ 1052.17	\$ 1183.69	\$ 1315.21
(2) AFTER-TAX BENEFITS OF DISPLACED VARIABLE COSTS (*)	\$ 68.39	\$ 136.78	\$ 205.17	\$ 273.56	\$ 341.95	\$ 410.35	\$ 478.74	\$ 547.13	\$ 615.52	\$ 683.91
(3) LESS OPERATION AND MAINTENANCE COSTS OF PEPS	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07
(4) NET BENEFITS OF DISPLACED VARIABLE COSTS (*) ((2)-(3))	\$ 31.32	\$ 99.71	\$ 168.10	\$ 236.49	\$ 304.88	\$ 373.27	\$ 441.66	\$ 510.05	\$ 578.44	\$ 646.84
(5) ADJUSTMENT FACTOR FOR OTHER TAX EFFECTS - \$ OF BENEFIT PER \$ OF INVESTMENT (DETAILED ON PREVIOUS PAGE)	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63
(6) CREDIT FOR DISPLACEMENT OF COAL CAPACITY BY PEPS AND GAS TURBINE (\$/KW)	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47
(7) MAXIMUM INVESTMENT PER INSTALLED KW ((4)*(5)+(6))	\$ 269.53	\$ 381.03	\$ 492.53	\$ 604.03	\$ 715.54	\$ 827.04	\$ 938.54	\$ 1050.04	\$ 1161.54	\$ 1273.04

(*) VARIABLE PORTION OF OVERALL UTILITY OPERATING COSTS IS PRIMARILY FUEL COSTS

DOLLAR BENEFITS OF PEPS INVESTMENT

(PRESENT VALUE IN 1976 DOLLARS)

CASE = 100

CAPACITY FACTOR = .308
(REPRESENTATIVE OF PHOENIX)

VARIABLE PORTION OF OVERALL UTILITY OPERATING COST (*) (LEVELIZED MILLS/KWH)

	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
(1) BEFORE-TAX BENEFITS OF DISPLACED VARIABLE COSTS (*)	\$ 208.81	\$ 417.61	\$ 626.42	\$ 835.23	\$ 1044.03	\$ 1252.84	\$ 1451.65	\$ 1670.45	\$ 1879.26	\$ 2088.06
(2) AFTER-TAX BENEFITS OF DISPLACED VARIABLE COSTS (*)	\$ 108.58	\$ 217.16	\$ 325.74	\$ 434.32	\$ 542.90	\$ 651.48	\$ 750.06	\$ 868.63	\$ 977.21	\$ 1085.79
(3) LESS OPERATION AND MAINTENANCE COSTS OF PEPS	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07	\$ 37.07
(4) NET BENEFITS OF DISPLACED VARIABLE COSTS (*) ((2)-(3))	\$ 71.51	\$ 180.09	\$ 288.67	\$ 397.24	\$ 505.82	\$ 614.40	\$ 722.98	\$ 831.56	\$ 940.14	\$ 1048.72
(5) ADJUSTMENT FACTOR FOR OTHER TAX EFFECTS - \$ OF BENEFIT PER \$ OF INVESTMENT (DETAILED ON PREVIOUS PAGE)	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63
(6) CREDIT FOR DISPLACEMENT OF COAL CAPACITY BY PEPS AND GAS TURBINE (\$/KW)	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47	\$ 218.47
(7) MAXIMUM INVESTMENT PER INSTALLED KW ((4)*(5)+(6))	\$ 335.05	\$ 512.07	\$ 689.10	\$ 866.12	\$ 1043.14	\$ 1220.17	\$ 1397.19	\$ 1574.21	\$ 1751.24	\$ 1928.26

(*) VARIABLE PORTION OF OVERALL UTILITY OPERATING COSTS IS PRIMARILY FUEL COSTS

SUMMARY OF ECONOMIC ANALYSIS

MAXIMUM INVESTMENT PER INSTALLED KW OF PEPS (1976 DOLLARS)

CASE = 100

VARIABLE PORTION OF OVERALL UTILITY OPERATING COST (*) (LEVELIZED MILLS/KWH)

CAPACITY FACTOR OF PEPS	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
.194 (CLEVELAND)	\$ 269.53	\$ 381.03	\$ 492.53	\$ 604.03	\$ 715.54	\$ 827.04	\$ 938.54	\$1050.04	\$1161.54	\$1273.04
.308 (PHOENIX)	\$ 335.05	\$ 512.07	\$ 689.10	\$ 866.12	\$1043.14	\$1220.17	\$1397.19	\$1574.21	\$1751.24	\$1928.26

(*) VARIABLE PORTION OF OVERALL UTILITY OPERATING COSTS IS PRIMARILY FUEL COSTS

APPENDIX E

SCENARIOS

Scenario 1 - Baseline Future and No Further Government Involvement in the Photovoltaic Market

General Conditions: The availability and cost of energy continue to be significant problems through the year 2000. The U.S. demand for energy continues to rise until 1980. This increased demand is caused by one or more of the following factors: (1) a long cycle of economic growth from 1976 to 1980; (2) long run energy conserving technologies are under utilized; (3) the lifestyles of the 1960's and early 1970's continue, thereby requiring increasing energy consumption per capita.

After 1980 the growth in U.S. energy demand slows. Many of the factors stimulating demand in the 1970's are reversed in the 1980's. These new trends may include: (1) economic growth slows and business cycles become more frequent and erratic; (2) a slower economic and energy consumption ethic becomes popular; (3) lifestyles shift away from energy intensive activities.

Growth in the supply of energy slowly continues through 1980. After 1980 supplies begin to decline. A variety of factors contributes to the decline, including: (1) the depletion of natural gas supplies by 1985; (2) increasing environmental controls; (3) slower than expected expansion of nuclear capabilities; (4) small contributions of new energy technologies; and (5) decreasing petroleum imports from foreign countries.

In the 1980's energy supply problems are not totally offset by decreased demand growth. Therefore energy prices continue to increase.

The Photovoltaic Market: The unfavorable economic outlook for photovoltaics in 1976 results in an abandonment of the ERDA program. Manufacturers curtail research and development programs by 1980. Sales volume of the photovoltaic market reverts back to 2 to 5 million dollars per year.

Space heating energy and energy for some industrial processes remain more critical problems than electricity from 1976 to 1980. The depletion of natural gas and high electricity costs are the major contributors to the crisis. Shortages of electricity are not a problem during the period. Some of the reasons for the adequate supply of electricity and its higher price through 1980 may include: (1) relatively abundant coal again becomes the principal fuel for electric generation; (2) public utility commissions modify regulatory procedures to restore the financial viability of utilities; (3) delays but no major curtailment of nuclear capacity expansion; (4) innovative peak-load pricing schemes (e.g., time of day pricing) reduce the long-run growth in peak electricity demand; and (5) reductions in environmental control and safety standards regarding coal mining and combustion increase the availability of coal.

Solar thermal technology applied to heating and cooling continues to develop through the 1980's. Successful federal demonstration programs aid in stimulating private sector involvement. By 1985, solar heating and cooling units are installed in 10% of the annual residential and commercial building starts.^{1/} A significant number of buildings are also retrofitted for solar heating and/or cooling by 1985. Photovoltaics are only used in remote areas through 1985.

The government program aimed at solar thermal electricity is continued. Fifty to 100 Mw's of solar thermal power are in operation (all government demonstrations) by 1985.^{2/}

As energy supplies decline in the 1980's, the production of electricity becomes more and more critical to the economic health of the U.S. The growth in electricity demand averages 6 to 7% between 1975 and 1985.^{3/}

Increased electricity demand, environmental problems, the high cost of fuels, and less-than-expected available nuclear capacity contribute to a set of problems facing electric utilities in the 1980's that are even more severe than in the 1970's.

The economic outlook for photovoltaics in the 1990's is much better than in the 1970's. Major economic competition comes from other non-conventional electric technologies such as solar thermal, geothermal, ocean thermal, wind, coal gasification, and biomass conversion. However, the lack of interest in photovoltaics between 1978 and 1990 is a serious drawback. Many of the alternative technologies have already been demonstrated and used by utilities. These technologies help relieve the electricity problems in the early 1990's. In addition, slower than expected economic growth and erratic business cycles keeps the cost of capital high. This high cost further reduces investor interest in PEPS.

Industry remains reluctant to invest and photovoltaics do not account for any significant amount of the U.S. energy supply by 2000.

1/ Projections contained in Project Independence Task Force Report--Solar Energy, Federal Energy Administration, November 1974, p. 1-7

2/ Creating Energy Choices for the Future, Energy Research and Development Administration, Vol. 2 (ERDA-48), pg. 33.

3/ Adequacy of Electric Power Fuel Supplies, 1975-1985, A Gakner, et al. Federal Power Commission, April 1976, pp. 8-9.

Scenario 2 - Numerous Energy Technologies Become Viable and Current ERDA
Plan for Photovoltaics Continue

General Conditions: Between 1976 and 2000, the U.S. energy situation undergoes a major change. Escalating energy prices, shortages and energy import deficits are replaced by price stability and an adequate supply of energy.

In fact, the U.S. becomes a small net exporter of energy--averaging about 4 quads per year by 2000.*

Over the period, numerous inroads are made in all phases of the energy problem. The most important advances concern conservation and nuclear energy. Energy conservation in buildings, industry, electric power transmission and transportation slow the growth in energy demand between 1976 and 1985. Further improvements after 1985 lead to stability and even slight reductions in U.S. energy consumption through 2000.

Energy supply problems are relieved considerably by nuclear power. Light water reactor capacity increases somewhat faster than expected through 2000 and becomes a major source of electrical energy. Advances are also made in fusion and the LMFBR but no operating plants are in existence by 1985. By 2000, some production facilities are operational.

A number of other electricity producing technologies also become economically viable over the period. Coal power plants capacity continues to increase as improved environmental control and safety devices are developed. Hydroelectric capacity increases slightly because smaller waterfalls become feasible for power generation. Geothermal technology advances more rapidly than expected and contributes to the national energy supply by 1985. Wind and ocean thermal technologies also become economically viable.

Non-electric energy technologies also help relieve national energy problems through 2000. Solar heating and cooling gains widespread commercialization by 1980 and reaches a higher than expected level of penetration in the residential and commercial market by 1985 (i.e., over 10% of the 1985 residential and commercial building starts are solar heated and/or cooled). Bioconversion and other synthetic fuels are successfully demonstrated before 1985. Economic viability follows but these fuels do not comprise a sizable portion of the transportation fuel market by 2000.

* Many of the quantities projected in this scenario are taken from "Scenario V--Combinations of All New Technologies: contained in Creating Energy Choices for the Future: A National Plan for Energy Research, Development and Demonstrations (ERDA-48, Vol. I, Energy Research and Development Administration, pg. IV-6).

In summary, the success of a large number of energy technologies significantly eases the nation's energy problems. However, they do not eliminate all the problems, especially in transportation. Numerous options exist for the production of electricity. In fact, not all nuclear and coal capacity that is available is being used in 2000.^{1/} The short-run solutions to the energy crisis of the 1970's turn out to be equally successful in the long-run. Therefore, some of the expected long-run energy options are no longer necessary by 2000.

The Photovoltaic Market: ERDA continues the photovoltaic RD&D plan. However, at each stage of development critics more vigorously question the need for the program. Delays in major demonstrations or technological advances are particularly devastating to the program. More technologies are competing for economic viability in electricity production than any other form of energy. Advances related to conventionally available electricity production facilities, such as coal or light water reactors, become extremely competitive. Delays in RD&D programs relating to any of the new energy technologies severely harm their chances for economic viability under these conditions.

Short-run energy solutions significantly ease the U.S. energy dilemma by 2000. Continuous advances in competing electrical technologies make economic viability for PEPS very difficult. Some delays occur in the ERDA-PEPS program between 1980 and 1990. As a result of these factors, PEPS only contribute minimally to the national energy supply by 2000.

^{1/} These conclusions parallel the findings of "Scenario V" of Creating Energy Choices for the Future, cited previously.

Scenario 3 - Baseline Future and Current ERDA Plan

General Conditions: The availability and cost of energy continue to be important through the end of the century. Energy prices rise steadily but moderately through 1990. Energy demand growth slows slightly but supply and environmental problems prevent price stability. (See Scenario 1 for further details.)

The Photovoltaic Market: The unfavorable economic outlook for photovoltaics in the 1970's results in an indepth ERDA program review. The review committee elects to continue the program for two major reasons. First, the future value of a number of cost factors, such as fuel prices and certain PEPS system components, are sufficiently uncertain to prevent early abandonment of the ERDA program. Photovoltaic power systems could be economically competitive, on a life-cycle basis, with conventional electric energy processes in the mid to late 1980's if fuel prices increase significantly. A major cost reduction or technical breakthrough in concentrators, cells and/or inverters could also improve economic viability.

The second major reason for continuing the program is that the technology offers significant societal benefits not considered by private sector investors. The private sector underestimates the social value of PEPS because (1) the value of saving our finite resources is higher than current prices reflect. (2) the development of the technology offers insurance against foreign energy curtailments. This insurance is of value to the nation. (3) The non-polluting nature of the technology is not fully reflected in its market price. (4) The environmental and national security costs of competing energy technologies are not included in their prices. (5) Existing subsidies to competing energy sources further distort their true social cost.

The review committee concludes that the market price comparisons made in the 1970's are inadequate for social decisions. Their recommendation is to continue the R, D, and D program but not to actively subsidize PEPS when it reaches commercialization. The RD&D program in photovoltaics does not represent a large investment by the nation (FY 77 obligated budget of 24.3 million for operations, plant and equipment and probably totalling not more than 1 billion dollars between 1975 and 1985). The long run return from the program could greatly exceed that amount if the energy situation deteriorated significantly.

The additional cost of subsidizing PEPS in its commercial stage of development would be considerable. For example, low-interest loans granted by the Rural Electrification Administration in 1970 cost the government 290 million dollars.^{1/} Continuation of the same loan volume for 4 years would result in a subsidy exceeding 1 billion dollars. Subsidies for PEPS

could probably not be limited to a single low-interest loan program. The value to the nation of PEPS development would probably not warrant this additional cost.

The committee's recommendations are approved and the program continues. By 1980 a silicon array production pilot plant has been designed and construction has begun, as well as an automated array assembly pilot plant. A number of test and demonstration units are operating by 1980, including a test and standards facility, DOD facilities and three residences. All of these projects are wholly supported by ERDA funds.

Industry response to the ERDA program is relatively slow through 1985. Most of the industry activity is aimed at obtaining ERDA funding. A number of factors contribute to the slow response. They include (1) the energy problem has continued but is not a crisis in the 1980's; (2) short-term energy solutions such as industry conservation and electric utility load management have reduced the threat of long-term energy shortages; (3) advances in coal handling and burning technologies and additional nuclear capacity have slowed the electricity price escalation; and (4) the commercialization of solar heating and cooling systems have dramatically reduced commercial and residential electricity bills; (5) capital for PEPS is only available at high interest rates.

Small increases in the size of the photovoltaic market result from increased usage in remote areas.

The trends in the photovoltaic industry established in the 1980's continue through the year 2000. No major national or international events seriously affect the PEPS market. By 2000, PEPS provides a small percentage (0.5 to 2 quads) of energy in the U.S. It is possible that the lower ERDA penetration goal is not met under these conditions.

1/ This cost assumes an average market interest rate of 9-1/2% and assumes the loans were repaid. Estimates obtained from The Economics of Federal Programs, Part I. Joint Economic Committee, Congress of the United States (GPO, 1972) p. 114.

Scenario 4 - Major Strides in Conservation and Government Incentives for PEPS Producers and Consumers

General Conditions: Between 1976 and 1985 conservation technologies develop rapidly, and more importantly, conservation techniques are implemented in all sectors of the U.S. Residential and commercial conservation efforts focus on improved building design and insulation, energy efficient HVAC equipment and conservation in major appliance energy use. Industry conserves energy used in manufacturing processes and utilizes waste heat extensively. Utilities improve the efficiency of electricity transmission and distribution. Waste heat from electrical generation is also used to meet space conditioning and process heat requirements for surrounding buildings and industries.

These conservation measures significantly lower the growth in energy demand between 1976 and 1985. Energy prices rise only moderately and few energy shortages persist. After 1985, the energy situation deteriorates again. Domestic energy supplies do not expand after 1980 but demand continues to increase. Unregulated energy prices rise steadily from 1985 to 2000. The improvements in conservation made in the late 1970's and early 1980's severely limit the potential effectiveness of new conservation programs. Advances in the development of new energy supply technologies and improvements in conventional sources between 1976 and 1985 provide some relief to the post-1985 problems. Nuclear and coal are major sources of this relief.

Photovoltaic Market: From 1976 to 1985, the government pursues its current research, development and demonstration program in photovoltaics. The impact of conservation on the energy situation before 1985 raises questions about the usefulness of photovoltaic R,D and D expenditures. Minor budget cutbacks occur, but the PEPS program is continued through 1985. Some unexpected delays occur in the achieving goals concerning photovoltaic cell production techniques and component cost reductions. However, all 1980 goals are achieved by 1985. A number of tests and demonstration units are operating between 1980 and 1985, including a test and standards facility, Department of Defense facilities and at least three residences. An automated array assembly pilot plant is in operation, as well as a silicon array production plant. These ERDA funded units are the only PEPS, other than in remote areas, in operation in 1985.

The year 1985 is extremely important to the future market penetration of PEPS. The nation's energy situation is at another turning point. In general, energy prices are beginning to escalate rapidly. Energy conservation can no longer keep energy demand within available supply limitations.

The Federal Government turns to a large number of energy supply technologies to reverse the 1985 energy price trends. Included in the government action is a review of the PEPS program. After the review, policy makers decide that stronger incentives are required to allow PEPS to contribute to the nation's energy supply by 2000. A program of commercial incentives or subsidies is instituted.

The subsidies take the form of; direct loan programs for certain utility company purchasers of PEPS; loan guarantees for corporate and individual PEPS investors; operation and maintenance cost subsidies for non-utility purchasers; back-up energy guarantees, and; loan programs for PEPS component producers. All of these programs (discussed more fully in Scenario 6) are instituted between 1985 and 1990.

PEPS penetration occurs first in the electric utility and corporate sector. Additional tax incentives for the purchase and operation of PEPS are also given to these two sectors under one of the numerous energy bills passed between 1985 and 1990. PEPS penetration in the residential sector lags behind the other sectors. The large number of other capital intensive energy options open to residences is one of the important reasons for the lower PEPS penetration

By 2000, U.S. coal and nuclear fuel use has expanded significantly from 1985 levels. A large number of "new" energy technologies are also being utilized to a small degree in the U.S. Photovoltaics is prominent among these "new" technologies, producing a small (0.5 to 2 quads) amount of energy annually by 2000.

Scenario 5 - Major Increase in U.S. Dependence on Electric Energy and
Current ERDA Plan for PEPS

General Conditions: Between 1976 and 2000 the demand for energy grows steadily. Conservation programs are not effective in curtailed demand growth in the residential, commercial, or transportation sectors. Industry conservation meets only limited success. Other reasons for the increased energy demand over the period could include; (1) a long cycle of economic growth from 1976 to 1980 and/or (2) the lifestyles of the 1960's and early 1970's continue, resulting in increased energy consumption per capita. After 1985, the transportation sector switches to electricity for mass transit systems, and, to the extent possible, electric automobiles.

Increased demand over the period leads to rising energy prices. Natural gas and oil prices exhibit the largest price increases. Electricity rates increase slower than most other energy alternatives. As a result, the nation's dependence on electrical energy grows dramatically. Coal and nuclear power plant capacity is inadequate for the projected increases in demand. A large amount of additional capacity is under construction between 1976 and 1985. However, the time required for environmental assessment and actual construction continues to average 4 to 6 years for coal-fired plants and 8 to 12 years for nuclear plants. Capacity additions are not able to keep pace with demand growth.

Pressure is placed on new electric technologies to help fill the electricity supply gap between 1985 and 2000. Geothermal, wind, ocean thermal, and solar thermal and photovoltaic technologies offer a greater potential to policy makers. Development and incentive programs begin after 1985. These technologies begin to contribute to the national electricity supply by 2000.

Slow expansion of electric generating capacity results in serious national problems. Petroleum imports continue to increase between 1976 and 1985. Petroleum prices increase simultaneously. The transportation problems remain critical to the end of the century. No major advances in electric powered transportation occurs before 1985. After 1985, only limited electric transportation is commercially available. Therefore, this sector becomes increasingly dependent on foreign petroleum and foreign controlled petroleum prices.^{1/}

^{1/} The transportation situation described here parallels Scenario II - Intensive Electrification of "A National Plan for Energy Research Development and Demonstration," Energy Research and Development Administration, (ERDA-48, June 1975), pg. IV-5.

The Photovoltaic Market: The projections of electric capacity requirements between 1976 and 2000 provide more than sufficient justification for continuing the ERDA program in photovoltaics. The ERDA budget for PEPS development is expanded between 1980 and 1985 to place increased emphasis on pilot cell production and array assembly plants.

Industrial interest in the ERDA photovoltaic program is intense, especially after 1980. Array cost reductions are attained reasonably close to ERDA target dates. However, rising electricity prices and its reduced availability bring PEPS close to economic feasibility in the early 1980's. Industrial research and development activities begin at the same time. By 1985 a relatively large number of new corporations are producing PEPS components, cells, or entire systems. Numerous PEPS are in operation in 1985.

By 1990 the development and commercialization of PEPS is being led by the private sector. The ERDA photovoltaic program provides some useful information, but the majority of production breakthroughs are the result of private sector R & D expenditures. A large number of PEPS systems are in operation by 1990. The systems are owned by utilities, corporations, and some residences. Extensive marketing efforts by competing PEPS manufacturers are a major factor in the relatively large PEPS penetration, especially systems for residences.

In 2000, a significant amount of electricity (1 to 5 quads) is produced from PEPS in the U.S. The nation's increased use of electricity and private sector PEPS development are the major determinants of this high level of penetration.

Scenario 6 - Baseline Future and Government Incentive Programs for PEPS

General Conditions: The baseline future outlined in scenario 1 also applies to this scenario. Energy prices rise steadily but moderately through 1990. Energy demand growth slows after 1980, but supply and environmental problems prevent price stability.

Photovoltaic Market: Stimulation of the photovoltaic market is not limited to research, development and demonstration (R, D and D). Commercialization incentives, or subsidies, are also instituted. The rationale for continuing the R, D and D program is again based on the social benefit argument. That is, the social benefits of the technology warrant government expenditures, even though PEPS are not economically attractive to the private sector.

The decision to provide permanent incentives (or subsidies) during the commercial stage of PEPS development receives considerable attention from policy makers. The cost to the government of these subsidies is usually substantially higher than R, D and D expenditures. Certain factions questioned whether the social benefits of PEPS warranted these additional costs. General energy conditions had not maintained their crisis situation through 1980. Therefore, the benefits that could be credited to PEPS are limited.

Proponents of the subsidy program argue that the social benefits outweighed the R, D and D budget and warranted at least a limited subsidy program. They argue that PEPS provides a form of national insurance against future energy crisis that the private sector is unwilling to purchase. Therefore, the government should bear a portion of the PEPS cost. Secondly, subsidies have been placed on other energy technologies with lower benefit/cost ratios than PEPS. Existing energy subsidy programs keep the cost of alternative energy sources artificially low. Therefore, private sector decisions concerning PEPS will not reflect the correct societal benefits and costs.

The subsidy program finally instituted is limited. The legislation that authorizes the subsidy cautions that the program cost should not exceed the value of a conservative estimate of future social benefits.

The subsidy or incentive program can indirectly affect the behavior of PEPS producers and/or purchasers. Alternatively, the government can enter directly into the production or purchase of PEPS. The latter option, i.e., direct involvement, is considered less appropriate than indirect incentives. The cost of direct involvement is the major reason for its neglect.

Both consumer and producers of PEPS receive incentives beginning in the early 1980's. The consumer section of the program focuses on financing and the reduction of cost uncertainties. Corporate and individual PEPS owners qualify under a loan guarantee program aimed at reducing interest costs and increasing the availability of financial capital. Operation and maintenance cost subsidies and backup energy guarantees are also part of the program. Utility companies, especially investor-owned, still face difficulty in obtaining private sector capital by 1980. A direct loan program, in which the government is the lender, is offered these utilities. The program parallels the Rural Electrification Administration loan program.

PEPS producers are also eligible for government guaranteed loans. However, the loans must be for photovoltaic cell or component production equipment. Some producers are still reluctant to invest in production equipment that may quickly become obsolete.

The incentive program continues through 1990. The stronger incentives for utilities result in the purchase of more PEPS by this sector than by corporations or individual homeowners. The smallest penetration occurs in the residential sector.

The advances in conservation, heat pumps, energy storage, solar heating, and cooling are of much greater interest to homeowners. All these technologies require significant capital investments. Most homeowners are therefore reluctant to also invest in PEPS. The other technologies carry the majority of the home's heating and cooling load, thereby reducing the electricity bill to a minor expense. Therefore, homeowners see little benefit from PEPS investment--both on a life-cycle and initial cost basis.

Corporations purchase only a limited number of PEPS through the 1980's. The incentive program significantly reduces the risk of a PEPS investment but does not sufficiently lower the life-cycle cost.

In 1990, additional Congressional action is taken. The penetration of PEPS through 1990 has not been limited by production capabilities. Therefore no new production incentives are authorized. The utility incentive program appears to be successful. The slow response of the residential sector offers little hope for significant future PEPS penetration. Therefore, the 1990 legislation focuses on corporations.

Modifications are made in the federal corporate income tax laws to reduce PEPS costs. These modifications may include:

- (1) Allowances for accelerated depreciation of the PEPS
- (2) A deduction for displacing fossil energy consumption with PEPS equivalent to the existing fossil fuel deductions.

(3) A special 25% investment tax credit for PEPS.

The second and third modifications to the tax structure greatly decrease the life-cycle cost of PEPS. Accelerated depreciation has only a minor impact on the cost. Between 1990 and 1995 corporate investment in photovoltaics increases significantly.

After 1995, the tax incentives are sharply reduced by Congress. The PEPS market stabilized from 1995 to 2000. By 2000 PEPS provide a significant amount of electricity in the U.S. (1 to 5 quads). The units are primarily owned by utilities and private corporations.

Scenario 7 - Limited Nuclear Power and Current ERDA Program for Photovoltaics

General Conditions: Nuclear energy in the United States receives widespread public scrutiny between 1977 and 1980. Popular opinion forces the Congress to authorize a moratorium on nuclear power plants in 1980. The moratorium indefinitely delays the construction of any new nuclear plants, halts construction on certain facilities not yet completed, and forces a few operating plants to shut-down. Some of the possible factors motivating this drastic action include: (1) increasing pressure from environmental and other social groups supported by strong public opinion, (2) a series of minor mishaps or a major accident in an existing reactor, (3) technical problems with nuclear waste transport and disposal or with other phases of the fuel cycle, or (4) sabotage of a reactor or robberies of nuclear fuel.

Before the moratorium is imposed, the national energy situation is beginning to be corrected. After 1980, energy is again the most critical problem facing the U.S.

Before the moratorium, all projections of the electric generation mix between 1980 and 2000 included major increases in the role of nuclear energy. The U.S. Department of the Interior projects nuclear plants will comprise approximately 12% of the installed generating capacity in 1980, 22% in 1985, and 48% in 2000.^{1/} Using these projections, the 1980 moratorium creates a supply gap in the order of 700,000 to 800,000 megawatts by 2000.

Government and private sector activity to find alternative energy sources remains high through the end of the century. No single energy source, including coal, can expand at a rate fast enough to fill the "nuclear gap."

Conservation programs are initiated with renewed interest after 1980. The industrial sector makes the most progress but not enough to ease electricity supply shortfalls. All available new electric technologies are utilized as soon as possible. Both government and private research and development activities are accelerated from 1980 to 2000. The U.S. reliance on foreign energy grows after 1980 to meet supply deficits. Prices of all energy in the United States increase rapidly after 1985. The rising energy prices persist to the end of the century.

The Photovoltaic Market: The 1976 ERDA Program plan for photovoltaics is continued through 1980. In 1980, the PEPS pilot production plants and demonstration facilities are in operation.

1/ United States Energy Through the Year 2000 (Revised) by Walter Dupree, Jr. and John Corsentino, Bureau of Mines, U.S. Department of the Interior December 1975, pg. 36.

After the moratorium is authorized, industrial interest in photovoltaics becomes intense. Considerable amounts of private sector funds are allocated to further advance the production techniques developed under the ERDA program. Between 1980 and 1985 a large number of new firms are formed which engage in the production of PEPS arrays and components.

By 1985, private sector involvement in PEPS production far exceeds ERDA expenditures. The demand for PEPS grows significantly after 1985. Utilities, faced with large capacity deficiencies, are early market entrants. However, renewed financial problems due to the nuclear moratorium and the need for large new capacity investments limit utility purchases of PEPS after 1985.

Industrial and commercial purchases of PEPS increase steadily from 1985 to 2000. A large number of single and multifamily residences also purchase PEPS after 1985.

By 2000, the amount of electricity produced by PEPS becomes highly significant (2 to 10 quads annually). Private sector development of improved production methods and the growing scarcity of electricity from conventional sources are the major factors stimulating the large penetration of PEPS.

Scenario 8 - Major Increase in U.S. Dependence on Electricity and Government Incentives for PEPS

General Conditions: The U.S. demand for electricity increases dramatically between 1976 and 2000. Conservation programs are relatively ineffective in slowing energy demand growth. Other possible reasons for the higher electricity demand are outlined in Scenario 5.

Nuclear and coal resources are used as extensively as possible to meet the electricity demand. However, lead times in the construction of additional capacity average 4 to 12 years. Supply gaps occur in the 1980's and persist to 2000. Petroleum imports increase to fill this gap. All energy prices, and especially petroleum prices, rise steadily between 1976 and 2000.

After 1985, new electric technologies are called on to relieve the supply constraints. The development of the breeder and fusion reactors progresses over the period but provides only minimal commercial electricity by 2000. Geothermal, wind, ocean thermal, solar thermal, and photovoltaic technologies offer somewhat greater potential before 2000.

The Photovoltaic Market: By 1980, the general trend toward increased electricity use is established. The ERDA research, development and demonstration program in photovoltaics becomes much more important to the national energy future than in the 1970's. Federal budget allocations for photovoltaics, and other new electric technologies, are increased substantially between the late 1970's and 1985.

Industrial involvement in the development and commercialization of PEPS is approximately equal to ERDA expenditures through 1980. Joint efforts by ERDA and industry result in major advances in production techniques and significant component cost reductions.

In the early 1980's PEPS became economically competitive. National energy trends indicate that PEPS may continue to be economically viable through 2000. Congress feels that PEPS is one of the few environmentally and socially acceptable solutions to increasing electricity shortages. In the early 1980's, Congress authorizes a widespread incentive program to assure private sector investment in PEPS.

The government incentive, or subsidy, program is intended to;

- (1) lower the life-cycle cost of PEPS through special tax deductions and credits,
- (2) reduce the cost uncertainty of PEPS investments,
- (3) make low cost financial capital available to overcome the PEPS high initial cost,
- and (4) stimulate the expansion of the PEPS production facilities.

The program costs the federal government several billion dollars per year from 1985 to 2000. Utilities, corporations, and individuals respond quickly. The incentive program makes PEPS considerably more attractive than other "new" technologies. PEPS penetrated most markets that would otherwise use alternative new electric technologies. PEPS penetrates other markets because generation capacity can be added using coal or nuclear plants. By 2000, the level of PEPS penetration will be highly significant (2 to 10 quads annually).

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APPENDIX F

THE EFFECT OF GOVERNMENTAL "SUBSIDIES" ON THE NUCLEAR POWER INDUSTRY

THE EFFECT OF GOVERNMENTAL "SUBSIDIES" ON THE NUCLEAR POWER INDUSTRY

Nuclear power is unique among the energy industries because it has been the product of governmental action since its inception during World War II. In fact, nuclear power has had a situation which is almost totally opposite to that prevailing in other energy industries, i.e., public policy issues regarding the application of nuclear power have centered on the degree to which nuclear energy should be released from governmental control and permitted to become part of the free enterprise system. The more normal route is for an energy industry to begin in the private sector, with governmental intervention resulting from a need for either regulation or assistance.

Federal responsibility for the development of civilian uses of nuclear energy was recognized by Congress in the Atomic Energy Act of 1946.^{1/} These responsibilities were clarified and broadened in the Atomic Energy Act of 1954.^{2/} The Act of 1946 placed the responsibility for nuclear power development with the Atomic Energy Commission (AEC). The AEC embarked on programs aimed at (1) obtaining the basic scientific and engineering data needed for proof of technical feasibility and safety of nuclear power generation and (2) demonstrating the actual economic feasibility of nuclear reactors for the generation of electricity.

In 1953, the AEC, with the encouragement of the Joint Committee on Atomic Energy, began a 5-year "experimental" program to develop promising reactor concepts. Construction was started on several power-producing reactors on AEC sites, and one AEC built and owned reactor provided steam to an investor-owned utility (Shippingport, Pennsylvania). The utility built the power generating equipment and operated the reactor under contract with the AEC.

The revision of the Atomic Energy Act in 1954 resulted in the continued expansion of the nuclear program by both government and industry. Most significant was the cessation of the government's monopoly of nuclear reactor ownership. For the first time, private industry was permitted to own and operate nuclear reactors. However, the 1954 Act still retained government ownership of all fissionable material. Private operators could obtain fissionable material only on lease from the federal government. Also, any fissionable material generated within the reactor was, by law, government property for which they paid a "fair value."

In 1955, a "Power Demonstration" program was added.^{3/} Under this program, the AEC and participating utilities cooperated in constructing and operating nuclear power plants on the utility grid. Two options in this program were (1) for the utility to purchase the steam from the AEC reactor or (2) for the utility to be given R&D assistance in designing and constructing their own reactor while no charge was made for the lease of the government-owned nuclear fuel.

In 1962, the AEC (by request) submitted to the President of the United States, a report on the state of the civilian nuclear power program.^{3/} As stated in this report:

"The overall objective of the Commission's nuclear power program should be to foster and support the growing use of nuclear energy, and importantly, to guide the program in such directions as to make possible the exploitation of the vast energy resources latent in the fertile materials, uranium-238 and thorium."

More specifically, the objectives outlined in the 1962 report were:

- "The demonstration of economic nuclear power by assuming the construction of plants incorporating the presently most competitive reactor types;
- The early establishment of a self-sufficient and growing nuclear power industry that will assume an increasing share of the development costs;
- The development of improved convertor and, later, breeder reactors to convert the fertile isotopes to fissionable ones, thus making available the full potential of the nuclear fuels;
- The maintenance of U.S. technological leadership in the world by means of a vigorous domestic nuclear power program and appropriate cooperation with, and assistance to, our friends abroad."

In 1964, the Private Ownership of Special Nuclear Materials Act^{4/} was passed. This Act provided for a transition period, during which time the ownership of nuclear fuel would be transferred from the federal government to private parties. Part of this legislation established a "buy-back" policy by guaranteeing a purchase price for plutonium and uranium-233. This "buy-back" policy has assured a purchase price for these materials since the 1950's. The prices were set at an estimated fuel value of \$10 per gram of plutonium and \$14 per gram of uranium-233. The "buy-back" program ended in 1970, even though plutonium cannot yet be used as a reactor fuel. It has been estimated that in a typical pressurized water reactor the fuel cost would be increased by 12% if its generated plutonium had no value.^{5/}

The 1964 law also authorized the AEC to provide toll enrichment services whereby raw materials can be purchased on the open market, processed in privately owned plants, enriched in the government-owned gaseous diffusion plants, and converted into fuel elements under private contract. This improved the overall outlook for the uranium mining and milling industry, as evidenced by the firming prices and signing of contracts for the delivery of uranium feed following 1967.^{6/} The availability of the enriching service also encouraged the user of nuclear power abroad and the subsequent sale of U.S. designed reactors using enriched uranium.

A more recent program by the government to transfer nuclear technology to private enterprise involves the next generation of uranium enrichment facilities. Legislation written by the Energy Research and Development Administration (ERDA) and proposed by Senator John Pastore and Representative Melvin Price, the "Nuclear Fuel Assurance Act," will permit ERDA to assist private industry in this extremely capital intensive venture. Under the proposed Act ERDA will "assist private industry to finance, construct, and operate all future uranium enrichment facilities to meet the projected fuel requirements for civilian nuclear power plants."^{7/}

The following discussion presents a summary review of some of the governmental actions on several categories. This is not intended to be a comprehensive listing of all government programs, but rather is an indication of the types of actions that have been pursued.

Fuel Cycle - All phases of the nuclear fuel cycle have been subsidized at some time. Mention has already been made of the effect of toll enrichment on the mining and milling industry. Another "subsidy" that occurred was a pricing action by the AEC. In order to encourage the emergence of a viable domestic uranium market, the AEC based its enriched uranium sale or lease charge schedule on \$8 per pound of U₃O₈ from 1958 through 1966 (plus a stretch-out period). This price was considerably above the market price of \$5 to \$6 per pound. The current price is slightly over \$10 per pound with an anticipated price of \$19.20 per pound in 1982 (constant 1975 dollars). Through a series of bonuses and guarantees of long-term contracts, the uranium industry was built from almost nothing in 1950, to a point where the U.S. is virtually self-sufficient in this field.

Other measures designed to stimulate the domestic uranium industry included an embargo on the enrichment of foreign uranium for domestic use.^{10/} This embargo was introduced for the expressed purpose of permitting the domestic industry to survive during the 1960's.

The nuclear fuel leasing policy permitted under the Atomic Energy Act of 1954 allowed the utility industry to enjoy several advantages. These were:^{6/}

The cost to industry of enriched uranium was lower than could have been obtained by industry alone because of the government-owned enrichment plants;

The lease charge rate for the fuel inventory was less than carrying charges under private financing; and

It was not necessary for a utility to raise the large amount of capital required for the fuel inventory at a time when the utility had to raise funds for plant construction.

The overall effect of not requiring the private ownership of nuclear fuel was to stimulate the nuclear industry.

The uranium enrichment phase of the nuclear fuel cycle has always been subsidized. This is primarily due to the requirement for security of the operating parameters involved in the production of weapons grade material. Under Section 161v of the Atomic Energy Act of 1954, the AEC in 1966 established a "ceiling" of \$30 per kilogram unit of separative work (actual price was \$26 in 1967). However, there was no attempt by the government to recover the true costs of enriching the uranium. When it was decided by the federal government to recover the cost of enrichment during the early 1970's, the price per separative work unit increased substantially. The current price for uranium enriching services is \$53.35 per separative work unit, with an increase to \$76 if the proposed Nuclear Fuel Assurance Act becomes law.

Radioactive waste disposal is an area that has recently received much attention from the federal government. Research and development on this subject have been carried on at Oak Ridge National Laboratory and other national laboratories. Currently, the government is assisting utilities in the ultimate disposal of radioactive wastes through storage and monitoring programs, as well as through the searching process for a permanent burial site.

In all of this complexity one fact is clear: The federal government (through the AEC and ERDA) has in the past operated as a nuclear fuel price administrator. It is not completely relinquishing this role so long as it continues to determine the price at which enrichment is performed. With the possibility of disposing of the government-owned enrichment facilities, the real costs of the entire fuel cycle cost/price structure should be realized.

Reactor Development - The AEC's Power Demonstration Reactor Program has provided assistance for a number of light water reactor (LWR) power plants. (This is in addition to the initial development of the pressurized water concept both in the nuclear navy and at Shippingport.) A substantial

sum of money continues to be invested in fission power reactor development, with the FY-1977 ERDA budget calling for \$823 million.^{8/} Some of the nuclear reactor concepts which have been directly subsidized by the government in the past are:

- Light water reactor
- Heavy water moderated reactor
- Light water breeder reactor
- High temperature gas cooled reactor
- Liquid metal fast breeder reactor
- Gas cooled fast breeder reactor
- Steam cooled fast breeder reactor
- Molten salt breeder reactor.

The government's general reactor technology programs were conducted by private industry, universities, and national laboratories. These programs covered almost all aspects of nuclear reactor design and construction activities. As such, these reactor development programs constituted an R&D subsidy of the nuclear industry.

Service Industries - In addition to the major equipment industry, a large and diverse service industry is required to implement a large-scale nuclear power program. These industries include the fabrication of fuels, nuclear reactor control equipment, and the chemical processing of spent reactor fuel. Many of the service industries were given considerable business by the government (AEC) during the 1950's and 1960's.

Besides giving the service industries business, the AEC decided that under no circumstances should the government compete with these service industries for private business. Fortunately because most of the service industries could start on a small scale, there was no risk of competition from the government. One exception to this was the processing of spent reactor fuel, where it would only be attractive to industry on a large scale. As part of the encouragement to private industry, the AEC informally promised business (to a limit of 100 operating days per year) to those who would enter the field.^{3/}

Research and Development Programs - In bringing the civilian nuclear power program to its present stage, the federal government has carried out a national research and development program. The scope of this program has purposely been kept very broad.

The primary justification for the expenditure of large amounts of money in nuclear reactor research and development, even after commercial nuclear power has been achieved, is based on the following line of reasoning. The class of reactors that are currently being constructed (LWR) is extremely inefficient in its use of nuclear raw materials. The goal of achieving more efficient resource utilization has been the primary driving force behind the large research and development program. Both convertor reactors and breeder reactors have been developed, with the main focus today being on the LMFBFR.

Future government R&D expenditures on nuclear energy are currently under debate. Uranium is only one of several fuels that can be used to generate electricity. Decisions concerning the research and development program that are motivated by a concern for the efficiency of the utilization of uranium cannot be properly evaluated except in the context of a consideration of the supply, demand, and net energy efficiency of all fuels used in generating electric energy.

The research and development program has included work in national laboratories and other government-owned facilities, primarily at governmental expense. It has included:

- Basic and applied research in physics, chemistry, and metallurgy;
- Development work on reactor components such as fuel elements, structural materials, moderators, coolants, heat exchangers, pumps, etc.;
- Development of processes such as chemical reprocessing, fuel fabrication, and waste disposal.

In addition to the basic research and development program, an extensive "Power Demonstration" program was pursued. This program, which has previously been discussed, was used to verify technology in actual practice, to yield economic information, and to provide experience on which to base improvements.

Reactor Safety - The achievement of the objective for reactor safety requires the development of safety related technology, safety criteria, safety codes and standards, safety research and development facilities, and a program whereby safety considerations can be transferred to regulatory agencies. This work has been carried out almost exclusively with government

funds in government facilities. Examples of the diverse nature of some of the safety features that have been investigated are:^{6/}

- Emergency core cooling systems
- Detection of incipient cracking in reactors piping and vessel materials
- Methods of scavenging radioactive gases in containment buildings
- Tests to determine plant component and instrumentation reliability
- Development of sodium-cooled reactor loops
- Fault-free analysis safety studies
- Siting related problems.

Much of the current expenditures in reactor safety are being directed toward solving safety problems of the advanced reactors (primarily the LMFBR).

Nuclear Insurance - The Price-Anderson provisions of the Atomic Energy Act of 1954, with amendments, afford protection to the public and to licensees and contractors from the risks associated with atomic energy. Price-Anderson provisions provide for a program of private insurance and governmental indemnity amounting to a maximum of \$560 million to cover damages that conceivably could arise from a nuclear incident.

The insurance pool (Nuclear Energy Liability-Property Assurance Association) will insure a single nuclear power reactor (or fuel reprocessing plant) for \$175 million on the facility and \$125 million for public liability. A system of fees and purchased government insurance extend this to the \$560 million (which will reach over one billion dollars by 1990).^{9/} Federal law requires Congress to "take whatever action" is necessary should consequences exceed this liability provision.

Some of the aspects of the various governmental subsidies to the nuclear power industry have been discussed. It is worthwhile to attempt to determine the results of these subsidies. One measure of the success of the overall program is to examine the installed nuclear capacity over the past 25 years in relation to the amount of government funding. The success of the program must also be measured against the stated objective:

"Thus, the proper role of government is to take the lead in developing and demonstrating the technology in such ways that natural economic forces will promote industrial applications and lead to a self-sustaining and growing nuclear power industry; the program should be guided in such directions that those economic forces will work toward ends in the public interest, including the long-range conservation of both our fossil and our nuclear fuel resources."^{3/}

One approach to assessing the results of the various governmental subsidy programs is to determine the cumulative funding level in relation to the installed nuclear capacity as a function of time. The same techniques can be applied to the amount of electric energy generated by the nuclear plants.

It was decided to use information from the appendices to the U.S. Budget for fiscal years 1956-1977 as the source of governmental expenditures. All figures prior to 1976 are actual expenditures, while those to 1985 reflect a budget approximately equivalent to the projected 1977 budget. This may not be too far in error, as historical data indicate that federal programs seldom make sudden large changes in funding, but rather tend to increase or decrease gradually over a period of years.

Information gathered on the installed nuclear generating capacity was taken from the Nuclear News "World List of Nuclear Power Plants" (February 1976 issue). Due to the long lead times required for the construction and licensing of a nuclear power plant, there is not a great deal of variation from this schedule which can reasonably be anticipated (barring a nuclear moratorium).

The quantities of electric power generated from nuclear facilities were taken from the Edison Electric Institute publication, "Statistical Year Book of the Electric Utility Industry for 1973."^{11/} Following the year 1975, projections of the energy produced from nuclear reactors were based on an assumed 60% load factor (in keeping with the past year or two of operating data). It was assumed that no nuclear power plants currently operating would be retired prior to 1985.

An attempt was made to segregate the funds expended by the AEC/ERDA/NRC into three categories: research and development programs, direct subsidy programs, and nuclear weapons related programs. Because of the secrecy involved in the weapons industry, it is almost impossible to completely separate this category from the others. For example, what portion of the expenditures in the area of uranium enrichment should be attributed to the

private industry category and how much to weapons? The solution to this type of problem was to assign an arbitrary (but conservative) fraction of the expenses to each category.

The R&D programs included the following portions of the yearly budget:

- Reactor development (including nuclear safety)
- Physical research
- Biology and medicine research
- Isotope development (later replaced by "applied energy technology").

The direct cost category included part of the following portions of the yearly budget:

- Procurement of raw materials
- Special nuclear materials (enrichment)
- Training, education, and information
- Program administration
- Regulations
- Program support
- Plant construction and capital equipment

● Credit for money received from private industry for lease of nuclear materials, uranium enrichment, waste disposal, etc.

It was recognized that some fraction of the direct costs should be related to the nuclear weapons effort. It was decided that the categories of (1) training, education and information, and (2) regulations were wholly within the area of a direct cost subsidy to the nuclear power industry. All of the remaining programs within the direct cost category were allocated 50% for weapons and 50% for the nuclear power industry. This is probably a conservative estimate, in that it probably overstates that portion which is allocated to weapons.

A cautionary note should be added at this point to explain that the absolute results of the analysis are not without uncertainty. The extremely large numbers calculated tend to make the results less believable. However, it is felt that the method of analysis used does present the basic facts of the case: namely, that the nuclear industry has been, and continues to be, heavily subsidized.

Figures 1 and 2 illustrate the results of the analysis. Table I presents the inputs and the calculations used in the figures. In Figure 1 the cumulative amount of money invested by the federal government is distributed over the cumulative installed nuclear generating capacity as a function of time. The government's investment is in constant 1975 dollars. Both the R&D component and the direct cost component of the total subsidy are shown. As of 1976, \$377/KWe have been invested in direct costs and \$498/KWe in nuclear R&D programs, making a total subsidy of \$875/KWe of installed nuclear capacity. By 1985 this subsidy will be reduced to \$356/KWe.

A similar treatment was used to distribute the funds expended by the government over the energy produced by the nuclear power plants as a function of time. The results are presented in Figure 2. The 1976 figures indicate that 21.8 mills/kw-hr in direct costs and 28.7 mills/kw-hr in R&D programs have been spent, for a total subsidy of 50.5 mills/kw-hr. This is a subsidy several times the normally quoted busbar cost of nuclear power.

Figure 1 - Cumulative Federal Subsidies to the Nuclear Power Industry
Distributed Over the Cumulative Installed Nuclear Generating
Capacity as a Function of Time.

Figure 2 - Cumulative Federal Subsidies to the Nuclear Power Industry Distributed Over the Cumulative Energy Generated by Nuclear Power Plants as a Function of Time.

TABLE I

AEC/ERDA/NRC EXPENDITURES
(MILLIONS \$)

Year	1 Procurement of Raw Materials	2 Special Nuclear Materials	3 Development of Nuclear Reactors	4 Physical Research	5 Biology and Medicine Research	6 Training, Education, Information	7 Isotope Development	8 Communities	9 Program Adminis- tration	10 Plant Con- struction and Equipment	11 Regulations	12 Applied Energy Technology (7)	13 Program Support (6+8+9)
1956	281.0	553.1	171.2	49.5	28.4	4.7		18.8	35.3	131.5			
1957	397.8	581.6	266.6	59.3	31.5	7.8		17.8	38.0	201.4			
1958	598.6	567.7	309.0	90.6	35.3	15.5	0.0	17.7	45.9	164.7			
1959	705.5	541.3	347.1	114.6	42.0	13.0	3.1	16.5	49.4	254.3			
1960	715.9	553.3	387.4	135.3	47.6	11.8	3.8	14.2	50.6	267.0			
1961	634.6	560.4	424.4	161.0	52.9	13.2	4.2	9.1	58.9	211.7			
1962	537.2	491.1	396.7	159.6	58.3	12.7	5.2	8.4	59.3	280.3			
1963	477.7	477.9	462.4	182.8	65.1	14.0	6.1	8.9	65.0	356.8			
1964	326.2	463.7	502.3	195.8	71.0	15.0	7.9	9.3	70.8	218.1			
1965	261.0	393.0	477.5	212.6	77.1	15.5	8.8	8.2	77.9	258.5			
1966	206.2	373.2	428.6	234.5	82.4	15.6	7.0	7.9	81.9	211.1			
1967	161.9	349.3	455.0	253.4	85.7	15.9	6.9	9.3	87.5	179.9			
1968	125.3	340.1	491.1	264.7	88.1	16.1	7.3	6.5	94.3	137.4			
1969	100.9	328.7	443.4	273.9	88.8	16.3	6.7	6.3	96.2	259.2	9.3		
1970		371.6	423.0	277.8	89.5	15.2	6.3	9.7	108.6	235.8	11.8		
1971		362.2	428.4	270.8	88.1	12.9	6.5	7.8	116.8	289.1	15.7		
1972		383.2	441.2	264.7	88.5					281.7	26.8	12.6	143.8
1973		429.5	477.9	280.9	111.4					369.8	45.3	10.6	141.0
1974		511.4	466.7	353.7	106.3					475.3	40.7	19.9	163.2
1975		467.6	571.4	482.8	134.6					525.3	53.2	16.7	200.8
1976		740.0	599.7	605.6	164.5					676.9	65.8	25.0	254.7
TQ		198.8	165.3	145.4	42.8					124.9	16.8	7.3	66.6
1977		1,011.9	802.3	684.6	174.7					1,005.6	76.6	34.0	287.8
1978		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0
1979		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0
1980		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0
1981		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0
1982		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0
1983		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0
1984		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0
1985		1,100.0	850.0	700.0	200.0					1,100.0	100.0	50.0	300.0

TABLE I (Continued)

	14	15	16	17	18	19	20	21	22	23	24	25	26
	Installed				Government	Cumulative							Cumulative
	Nuclear	Cumulative	Electricity	Cumulative	R & D	R & D	R & D	R & D	Government	Cumulative	Direct Cost	Direct Cost	Governmental
Year	Capacity	Capacity	Generated	Generation	Programs	Expenses	Subsidy	Subsidy	Direct Costs	Direct Costs	Subsidy	Subsidy	Subsidy
	(Mwe)	(Mwe)	(10 ⁹ kw-hr)	(10 ⁹ kw-hr)	(10 ⁶ \$)	(10 ⁶ \$)	(\$/Kwe)	(mils/kw-hr)	(10 ⁶ \$)	(10 ⁶ \$)	(\$/Kwe)	(mils/kw-hr)	(10 ⁶ \$)
1956					249.1	249.1	∞	∞	500.1	500.1	∞	∞	749.2
1957			0.01	0.01	357.4	606.5	∞	60,650.0	612.2	1,112.3	∞	111,230.0	1,718.8
1958			0.17	0.18	434.9	1,041.4	∞	5,785.6	699.0	1,811.3	∞	10,062.8	2,852.7
1959			0.19	0.36	506.8	1,548.2	∞	4,300.6	783.3	2,594.5	∞	7,206.9	4,142.7
1960	200	200	0.52	0.88	574.1	2,122.3	10,611.5	2,411.7	800.2	3,394.7	16,973.5	3,857.6	5,517.0
1961	175	375	1.69	2.57	642.5	2,764.8	7,372.8	1,075.8	741.0	4,135.7	11,028.5	1,609.2	6,900.5
1962	335	710	2.27	4.84	619.8	3,384.6	4,767.0	699.3	690.4	4,826.1	6,797.3	997.1	8,210.7
1963	68	778	3.21	8.06	716.4	4,101.0	5,271.2	508.8	695.4	5,521.5	7,097.0	685.0	9,622.5
1964		778	3.34	11.40	777.0	4,878.0	6,269.9	427.9	547.8	6,069.3	7,801.2	532.4	10,947.3
1965		778	3.66	15.06	776.0	5,654.0	7,267.4	375.4	500.4	6,569.7	8,444.3	436.2	12,223.7
1966	860	1,638	5.52	20.58	752.5	6,406.5	3,911.2	311.3	428.4	6,998.1	4,272.3	340.0	13,404.6
1967		1,638	7.66	28.23	801.0	7,207.5	4,400.2	255.3	389.9	7,388.0	4,510.4	261.7	14,595.5
1968	1,005	2,643	12.53	40.76	851.2	8,058.7	3,049.1	197.7	336.0	7,724.0	2,922.4	189.5	15,782.7
1969	1,298	3,941	13.93	54.69	812.8	8,871.5	2,251.1	162.2	371.0	8,095.0	2,054.0	148.0	16,966.5
1970	2,439	6,380	21.80	76.48	796.6	9,668.1	1,515.4	126.4	311.6	8,406.6	1,317.6	109.9	18,074.7
1971	2,713	9,093	37.90	114.38	793.8	10,461.9	1,150.5	91.5	273.1	8,679.7	954.5	75.9	19,141.6
1972	5,584	14,677	54.03	168.41	807.0	11,268.9	767.8	66.9	325.4	9,005.1	613.6	53.5	20,274.0
1973	5,587	20,264	83.29	251.71	880.8	12,149.7	599.6	48.3	358.6	9,363.7	462.1	37.2	21,513.4
1974	9,865	30,129	136.99	388.70	946.6	13,096.3	434.7	33.7	311.1	9,674.8	321.1	24.9	22,771.1
1975	6,323	36,452	171.40	560.10	1,205.5	14,301.8	392.3	25.5	463.0	10,137.8	278.1	18.1	24,439.6
1976	9,885	46,337	243.55	804.00	1,394.8	15,696.6	338.7	19.5	605.6	10,743.4	231.9	13.4	26,440.0
1977	6,631	52,968	278.40	1,082.00	1,695.6	17,753.0	335.2	16.4	824.5	11,700.3	220.9	10.8	29,453.3
1978	7,448	60,416	317.55	1,400.00	1,800.0	19,553.0	323.6	14.0	910.0	12,610.0	208.7	9.0	32,163.0
1979	10,979	71,395	375.25	1,775.00	1,800.0	21,353.0	299.1	12.0	910.0	13,520.0	189.4	7.6	34,873.0
1980	12,634	84,029	441.66	2,216.00	1,800.0	23,153.0	275.5	10.4	910.0	14,430.0	171.7	6.5	37,583.0
1981	14,632	98,661	518.56	2,735.00	1,800.0	24,953.0	252.9	9.1	910.0	15,340.0	155.5	5.6	40,293.0
1982	23,884	122,545	644.10	3,379.00	1,800.0	26,753.0	218.3	7.9	910.0	16,250.0	132.6	4.8	43,003.0
1983	19,065	141,610	744.30	4,123.00	1,800.0	28,553.0	201.6	6.9	910.0	17,160.0	121.2	4.2	45,713.0
1984	19,209	160,819	845.27	4,969.00	1,800.0	30,353.0	188.7	6.1	910.0	18,070.0	112.4	3.6	48,423.0
1985	11,314	172,133	904.73	5,873.00	1,800.0	32,153.0	186.8	5.5	910.0	18,980.0	110.3	3.2	51,133.0

TABLE I (Concluded)

	27	28	29	30	31	32	33	34	35	36	37	38	39
	Total	Total	Money	Adjusted	Adjusted	Adjusted	Adjusted	Adjusted	Adjusted	Adjusted	Adjusted	Adjusted	Adjusted
	Subsidy	Subsidy	Index	R & D	Cumulative	R & D	R & D	Direct Costs	Cumulative	D.C. Subsidy	D.C. Subsidy	Total Subsidy	Total Subsidy
Year	(\$/kwe)	(mils/kw-hr)	(1975 = 1.000)	(10 ⁶ \$)	(10 ⁶ \$)	(\$/kwe)	(mils/kw-hr)	(10 ⁶ \$)	D.C. (10 ⁶ \$)	(\$/kwe)	(mils/kw-hr)	(\$/kwe)	(mils/kw-hr)
1956	"	"	2.009	500.4	500.4	"	"	1,004.6	1,004.6	"	"	"	"
1957	"	171,880.0	1.943	694.5	1,194.9	"	119,949.0	1,189.7	2,194.3	"	219,430.0	"	338,920.0
1958	"	15,848.3	1.913	831.8	2,026.7	"	11,259.4	1,336.9	3,531.2	"	19,617.8	"	30,877.2
1959	"	11,507.5	1.871	948.4	2,975.1	"	8,264.2	1,465.8	4,997.0	"	13,880.6	"	22,144.7
1960	27,585.0	6,269.3	1.840	1,056.3	4,031.4	20,157.0	4,581.1	1,472.3	6,469.3	32,346.5	7,351.5	52,503.5	11,932.6
1961	18,401.3	2,685.0	1.824	1,171.8	5,203.2	13,875.2	2,024.6	1,351.4	7,820.7	20,855.2	3,043.1	34,730.4	5,067.7
1962	11,564.4	1,696.4	1.791	1,110.0	6,313.2	8,891.8	1,304.4	1,236.5	9,057.2	12,756.6	1,871.3	21,648.5	3,175.7
1963	12,368.3	1,193.9	1.765	1,264.4	7,577.6	9,739.8	940.1	1,227.3	10,284.5	13,219.2	1,276.0	22,959.0	2,216.1
1964	14,071.1	960.3	1.738	1,350.2	8,927.8	11,475.3	783.1	951.9	11,236.4	14,442.7	985.6	25,918.0	1,768.8
1965	15,711.7	811.7	1.700	1,319.3	10,247.1	13,171.1	680.4	850.7	12,087.1	15,536.1	802.6	28,707.2	1,483.0
1966	8,183.5	651.3	1.646	1,238.6	11,485.7	7,012.0	558.1	705.2	12,792.3	7,809.7	621.6	14,821.7	1,179.7
1967	8,910.6	517.0	1.599	1,280.8	12,766.5	7,794.0	452.2	623.4	13,415.7	8,190.3	475.2	15,984.2	927.5
1968	5,971.5	387.2	1.530	1,302.5	14,069.0	5,323.1	345.2	514.2	13,929.9	5,270.5	341.8	10,593.6	686.9
1969	4,305.1	310.2	1.457	1,184.2	15,253.2	3,870.4	278.9	540.5	14,470.4	3,671.8	264.6	7,542.1	543.5
1970	2,833.0	236.3	1.383	1,101.7	16,354.9	2,563.5	213.8	430.9	14,901.3	2,335.6	194.8	4,899.1	408.7
1971	2,105.1	167.4	1.316	1,044.5	17,399.4	1,913.5	152.1	359.4	15,260.7	1,678.3	133.4	3,591.8	285.5
1972	1,381.3	120.4	1.264	1,019.6	18,419.0	1,255.0	109.4	411.1	15,671.8	1,067.8	93.1	2,322.7	202.4
1973	1,061.7	85.5	1.193	1,050.7	19,469.7	960.8	77.3	427.8	16,099.6	794.5	64.0	1,755.3	141.3
1974	755.8	58.6	1.087	1,029.3	20,499.0	680.4	52.7	338.3	16,437.9	545.6	42.3	1,226.0	95.0
1975	670.5	43.6	1.000	1,205.5	21,704.5	595.4	38.8	463.0	16,900.9	463.6	30.2	1,059.1	68.9
1976	570.6	32.9	0.971	1,354.2	23,058.7	497.6	28.7	588.0	17,488.9	377.4	21.8	875.1	50.4
TQ	-	-	-	350.3	23,409.0	-	-	128.5	17,617.4	-	-	-	-
1977	556.1	27.2	0.943	1,598.3	25,007.3	472.1	23.1	777.2	18,394.6	347.3	17.0	819.4	40.1
1978	532.4	23.0	0.915	1,647.2	26,654.5	441.2	19.0	832.8	19,227.4	318.3	13.7	759.4	32.8
1979	488.5	19.6	0.888	1,599.3	28,253.8	395.7	15.9	808.5	20,035.9	280.6	11.3	676.4	27.2
1980	447.3	17.0	0.863	1,552.7	29,806.5	354.7	13.5	785.0	20,820.9	247.8	9.4	602.5	22.8
1981	408.4	14.7	0.837	1,507.5	31,314.0	317.4	11.4	762.1	21,583.0	218.8	7.9	536.1	19.3
1982	350.9	12.7	0.813	1,463.6	32,777.6	267.5	9.7	739.9	22,322.9	182.2	6.6	449.6	16.3
1983	322.8	11.1	0.789	1,420.9	34,198.5	241.5	8.3	718.3	23,041.2	162.7	5.6	404.2	13.9
1984	301.1	9.7	0.766	1,379.5	35,578.0	221.2	7.2	697.4	23,738.6	147.6	4.8	368.8	11.9
1985	297.1	8.7	0.744	1,339.4	36,917.4	214.5	6.3	677.1	24,415.7	141.8	4.2	356.3	10.4

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APPENDIX G

DISCUSSION OF ENERGY INDUSTRY SUBSIDIES

DISCUSSION OF ENERGY INDUSTRY SUBSIDIES

I. Introduction

The term subsidy frequently refers to a government program or policy designed to aid a particular industry, organization, or type of enterprise. Normally, subsidies have been justified for many U.S. industries as a necessary expenditure or cost required for vital national interests or defense. The tariff system acts as a subsidy structure, since it enables the protection of certain industries and results in higher costs for their goods in the American market. Depletion allowances have provided subsidy-like benefits to several industries (especially petroleum), as have accelerated tax amortization write-offs, provision of free or less than full cost government services, and many others.

Generally a subsidy, at least conceptually, involves a governmental action designed to improve the economic position of an industry or individual. The aim is to enhance profitability which would be less without the protection of these various statutes. While designed to soften the full force of competition, the implicit objective of each governmental action has been to encourage further development and commercialization of one or more segments of the energy industry. Generally, each action was taken in response to a specific problem which was believed to be a barrier restricting commercial development. Historically, some segments of the energy industry have enjoyed many special governmental provisions which have directly or indirectly subsidized their operations.

Since the early 1900's a series of legislative actions have evolved a maze of overlapping and fragmented regulations and subsidies. The provisions of each action have not equally applied to each industry segment. The results of each provision have not had the same impacts on each segment. While a number of special provisions that benefit the industry can be located, analysis of their impact cannot. Only a few studies have attempted to assess the impact of the existing legislative maze. And these studies have been narrow in scope, limiting themselves to the evaluation of specific provisions of specific industry segments, rather than attempting a comprehensive industry analysis.

Table I highlights the influence a few governmental subsidy programs have had on different energy industry segments. The following sections of this appendix discuss the origin, rationale, and impact of these special governmental provisions in detail. The objective is not to provide a comprehensive analysis of all the subsidies provided to each industry segment, but rather to illustrate the significant influence certain governmental actions have had on a few energy industry segments.

TABLE I

TYPICAL SUBSIDIES UTILIZED BY MEMBERS OF THE ENERGY INDUSTRY

			Energy Costs			% Impact On Costs
		Annual Subsidy (\$ millions)	With Subsidy Total (\$ millions)	Per unit	Without Subsidy (\$ millions) Per Unit	
II. <u>Special Tax Provisions (Decreases Costs)</u>						
<u>(Oil and Gas Industry)</u>			<u>5/</u>	<u>/barrel^{5/}</u>	<u>/barrel</u>	
(1) Percentage Depletion						
CONSAD Study (1965 Base)	1,200 ^{1/}	12,018	\$2.86	13,218	\$3.14	10.0%
(2) Intangible Drilling Exp.						
CONSAD Study (1965 Base)	\$119-\$324 ^{1/}	12,018	2.86	12,137-12,342	\$2.89-2.94	1.0-2.7%
Both (1) and (2)	1,4					
CONSAD Study (1965 Base)	1,400	12,018	2.86	13,419	3.19	11.6%
Span et al. Study						
(1971 Base)	2,500 ^{2/}	18,724	3.39	21,224	3.84	13.4%
(3) Foreign Tax Credit						
Ways and Means Study						
(1971 Base)	500-600 ^{4/}	18,724	3.39	19,224-19,324	3.48-3.50	2.7-3.2%
III. <u>Import Controls (Increases Prices)</u>						
<u>Domestic Petroleum Industry</u>		<u>5/</u>	<u>5/</u>	<u>/barrel^{5/}</u>	<u>/barrel</u>	
(1) Presidential Petroleum Study						
(1967 Base)	3,500 ^{6/}	13,433	2.93	9,933	2.16	26.1%
(2) Cicchette and Gillen						
(1970 Base)	7,400 ^{7/}	17,059	3.18	9,659	1.80	43.4%

TABLE I (Continued)

	<u>Energy Costs</u>					<u>% Impact On Costs</u>
	<u>Annual Subsidy (\$ billions)</u>	<u>With Subsidy</u>		<u>Without Subsidy</u>		
		<u>Total (\$ billions)</u>	<u>Per Unit</u>	<u>(\$ billions)</u>	<u>Per Unit</u>	
IV. <u>Federal Subsidy Programs</u> (Decreases Costs)			mils./kwh		mils/kwh	
(1) Econ. of Nuc. Power (1975 Base)	\$24.4	6.1	12.5 ^{8/}	30.5	62.9	403%

Discussion

II. Special Tax Provisions: The figures in Table I reflect the size of some tax subsidies provided to the domestic petroleum industry. The base year in which the annual subsidy was estimated is indicated. The percentage impact on cost only serves as an example of the influence these tax provisions had on petroleum costs at that point in time. No attempt has been made to expand the time frame to calculate the cumulative effect of these special tax provisions or measure their impact on other members of the energy industry. All subsidies are calculated in terms of tax revenue lost by the U.S. Treasury.

- 1/ CONSAD Research Corporation, The Economic Factors Affecting the Level of Domestic Petroleum Reserves, Pt. 4, U.S. Congress Committee on Ways and Means and Senate Committee on Finance, Tax Reform Studies and Proposals, U.S. Treasury Department, Government Printing Office, Washington (1969).
- 2/ Spann, Robert M., Edward W. Erickson, and Stephen W. Millsaps, Percentage Depletion and the Price and Output of Domestic Crude Oil, Panel discussion on general tax reform, Panel No. 9--Natural Resources, U.S. Congress, House Committee on Ways and Means, 93rd Congress, 1st session, Government Printing Office, Washington (1973).
- 3/ U.S. Congress, Senate Committee on Interior and Insular Affairs, Financial Requirements of the Nation's Energy Industry, Serial no. 93-5, March 6, 1973.
- 4/ Staff of the Joint Committee on Internal Revenue Taxation, Energy Taxation: Possible Modifications in the Tax Treatment of Foreign Oil and Gas Income, study no. 3, prepared for use by the Committee on Ways and Means, U.S. Congress, 94th Congress, Government Printing Office, Washington (1974).

TABLE I (Concluded)

Discussion (Concluded)

5/ Bureau of Mines, Mineral Industry Surveys, "Petroleum Statements" Annual.

III. Import Controls: These figures reflect the added costs borne by the U.S. public in terms of costs paid over the competitive world prices.

6/ Executive Office of the President, Office of Emergency Planning, A Report to the President, by the Petroleum Study Committee (September 4, 1967) p. 2. Resources for the Future, U.S. Energy Politics: An Agenda for Research (1963).

7/ Charles J. Cicchetti and William Gillen, "The Mandatory Oil Import Quota Program: A Consideration of Economic Efficiency and Equity," in the Economics of Federal Subsidy Programs, U.S. Congress, Joint Economic Committee, Washington, U.S. Government Printing Office, p. 1013.

8/ ERDA, The Economics of Nuclear Power, ERDA, Office of Public Affairs (EDM-068 (-76)), March 1976.

A comprehensive discussion of the subsidy program provided the nuclear industry was contained in Appendix F. The purpose of this appendix is to discuss subsidies provided to other energy segments. The appendix is comprised of three main parts: the first describes the impact several special tax provisions have had on several industry segments (especially petroleum); the second provides examples of how governmental policies designed in the name of "national security" have subsidized industry segments by increasing the energy prices consumers pay and by reducing competition; thirdly, several direct federal subsidy programs provided to demonstrate the economic and technical feasibility of industry segments are identified. Finally, an annotated bibliography is included.

Briefly, Table I first highlights several distinctive tax provisions certain energy industry segments (the oil and gas industries) benefit from. Apart from certain types of capital gain transactions, the important special provisions applicable to specific industry segments are of three types:

1. The most important, and controversial, special tax provision was and is the "percentage depletion allowance." Under this provision a percentage^{1/} of the gross value of oil produced (up to a limit of 50% of net income) could be deducted before computing income for income tax purposes. In origin this was to serve as a substitute for an earlier method of allowing an annual depletion charge against the capital value of oil discovered, in lieu of depletion based on costs incurred. Some studies indicate the impact of this tax provision may have reduced the oil producers costs by 10% or more.
2. Intangible drilling expenses, which represent the major fraction of capital costs of wells, are permitted to be charged as current expenses instead of being written off over the life of the wells. This has the same advantage, in an extreme form, of any system of accelerated depreciation. It decreases current income taxes during a period of development and gives command over a volume of cash funds that may be thought of as an interest-free loan.

^{1/} The percentage depletion allowance is currently being discounted for major oil and gas companies, but was 22% from 1970 through 1975; 27.5% from 1926 through 1969; and varying amounts before 1926.

The effect of this provision on crude oil costs has been estimated to be from 1% to 14%.^{1/}

3. Foreign tax credits used by the oil and gas industry on treatment of income earned abroad have also acted as a subsidy. Their impact has been estimated at approximately 3%.

Secondly, the subsidies provided to several industry segments in the form of import controls used to guarantee national security are shown in Table I. The rationale for the use of import controls, including quotas and tariffs, is to assure the United States economy of a stable energy supply. The impact of these controls has been to reduce competition and artificially increase energy prices paid by the consumer. Studies assessing the subsidy and social costs of import control programs vary, but indicate it to be substantial. For example:

- (1) The magnitude of the subsidies provided to domestic oil companies by consumers through artificially increased prices range from 25^{2/} to 45%.^{3/}
- (2) Additional social costs borne by the public measured in terms of economic inefficiencies attributable to import quotas were estimated to equal \$3.5 billion in 1970.^{3a/}

1/ Estimates of the combined impact of these two special provisions have ranged from 12% to 24%. Since actual capital outlays are recoverable through current expensing of intangible costs and depreciation of tangible assets, the depletion allowance is in effect an extra benefit. Moreover, it goes on without limit of time or amount, as long as there was a net income.

2/ Executive Office of the President, Office of Emergency Planning, A Report to the President, by the Petroleum Study Committee, September 4, 1962, p. 2; Resources for the Future: U.S. Energy Policies, an Agenda for Research, 1968.

3/ Charles J. Cicchetti and William Gillen, "The Mandatory Oil Import Quota Program: A Consideration of Economic Efficiency and Equity,;" in The Economics of Federal Subsidy Programs, U.S. Congress, Joint Economic Committee, Washington, U.S. Government Printing Office, p. 1013.

3a/ Ibid.

The final program area of subsidies covered by this appendix concerns government participation and support of energy industry projects and R&D. These programs have acted to reduce the financial and institutional barriers restricting the development and commercialization of several industry segments. The case history concerning the growth of the nuclear power industry provided in Appendix F illustrated the immense impact of government subsidies. Without these special governmental actions involving R&D programs, incentives to discover uranium and funding of nuclear power stations, the nuclear industry would have never developed to its present stage of commercialization.

- (1) A full cost analysis of 1976 subsidies provided the nuclear energy industry amounts to 50.5 mills/kw-hr. This consists of 21.8 mills/kw-hr indirect costs and 28.7 mills/kw-hr in R&D programs. The magnitude of this subsidy equals four times the normally quoted busbar costs for nuclear energy.
- (2) The total amount of subsidies provided to the nuclear industry since 1956 has amounted to \$26.4 billion. This is equivalent to \$40.5 billion in constant 1975 dollars.

II. SPECIAL TAX PROVISIONS

A. Description

Historically segments of the energy industry (especially petroleum) have received special treatment under federal tax laws and regulations. The depletion allowance, expensing of intangible drilling costs, and the U.S. tax credit for payment to foreign governments for production rights have acted as subsidies. The result of such special tax treatment has been a loss of revenue to the U.S. Treasury. The descriptions of the distinct tax provisions for the petroleum and gas industries do not equally apply to other mineral extractive industries.

1. Depletion allowance: Most firms engage in oil, gas, and other mineral extraction are permitted to include their business costs a "depletion" allowance for the exhaustion of the mineral deposits. Depletion is similar in concept to depreciation. The depletion allowance is used to recover the cost of a mineral deposit. There are two methods of calculating depletion: percentage depletion and cost depletion. Those who qualify for the percentage depletion must use it, when the percentage depletion is greater than the cost depletion.

Under percentage depletion, a taxpayer (individual or corporation) deducts from taxable income a fixed percentage of gross income resulting from mineral extraction as a depletion allowance regardless of the amount invested in the deposit. The deduction for gas and oil (which was 27.5% from 1926-69) is now set at 22% of gross income. However, beginning in 1975, the percentage depletion allowance was repealed for major oil and gas companies. Other companies (independents) have been exempted from repeal of 2,000 barrels a day for 1975. The amount of this exempt portion is being phased down gradually to 1,000 barrels a day. In addition, beginning in 1981, the depletion rate will be gradually phased down to 15% for qualifying producers.

Percentage depletion also applies to other mineral resources at percentages currently ranging from 22 to 5%. Sulphur, uranium, and most other metal minerals in the U.S. qualify for the 22% rate; however, domestic gold and iron ore qualify for a 15% rate; most minerals mined outside the U.S. qualify for a 14% rate; coal qualifies for a 10% rate; and several forms of clay, gravel, and stone qualify for 5 and 7.5% rates.

The impact of the percentage depletion allowance on coal production is changing. The rising price of imported oil has increased the average price of all oil. Coal has been substituted for oil, resulting in dramatic coal price increases. The price increases will probably increase the effective 6% rate currently to nearly to statutory limit of 10% in the near future.

Percentage depletion may not exceed 50% of net income from the property. This limitation is known as the "net income limitation." The total cost which can be recovered by percentage depletion allowance is not limited to the cost of the property.

The other depletion method--cost depletion--resembles depreciation based upon the number of units produced. (The share of the original cost of the estimated total production--over the lifetime of the well or mine--which is produced in that year.) Using cost depletion, capital recovery cannot exceed the initial cost.

Percentage depletion usually results in a faster recovery than cost depletion, and the cost may be recovered many times over since percentage depletion is not limited to original cost.^{1/} Until recently, practically all depletion by the oil and gas industry was taken as a percentage depletion rather than cost depletion. Expenses of dry holes, intangible drilling costs (if expressed), and tangible drilling costs can all be deducted in addition to percentage depletion.

^{1/} Professor J. Reid Hambrick estimated in testimony before the Ways and Means Committee (February, 1973) that percentage depletion deductions amount to 16 times original cost.

Impacts of percentage depletion include: (1) decrease in the price of qualifying oil, natural gas, and other minerals, indirectly encouraging consumption; (2) the bidding "up" of the price of drilling and mineral rights; and (3) encouragement of the development of new deposits resulting in production increases.

Estimated Revenue Loss
(In Millions of Dollars)

<u>Fiscal Year</u>	<u>Individuals</u>	<u>Corporations</u>	<u>Total</u>
1977	575	1,020	1,595*
1976	500	1,080	1,580*
1975	465	2,010	2,475*
1974	-	-	N.A.**
1973	-	-	1,700**
1972	-	-	985**
1971	-	-	980**
1970	-	-	1,470**

* Jane Gravell, et al., Tax Expenditures: Compendium of Background Material on Individual Provisions, Prepared for U.S. Senate Committee on the Budget, March 17, 1976 (p. 31).

** Douglas, Lee, et al., Federal Subsidy Programs, prepared for Joint Economic Committee, October 18, 1974 (p. 101).

Prior to 1975, oil and gas accounted for the bulk of percentage depletion. Since the 1975 repeal of percentage depletion for most oil and gas production, approximately 75% of current domestic gas and oil production is not eligible for this deduction. This will result in a reduction in revenue loss by the U.S. Treasury in the form of tax revenues beginning in 1976 as shown in the chart above. The sales of all other mineral deposits are unaffected.

2. Expensing of intangible drilling, exploration, and development costs: Certain expenses incurred in drilling for oil and gas can be deducted (or expensed) from taxable income. The intangible drilling costs required to bring a well into production include items such as labor, material, supplies, and repairs. (Tangible expenses are those for assets such as tanks and pipes recovered through depreciation.) Costs incurred in mining activities for exploration and development may also be "expensed."

The advantage in "expensing" these costs involve the structure of the tax laws. Usually, expenditures designed to improve assets that yield an income stream for several years must be capitalized and deducted over the period in which the assets produce income. The tax advantage of treating these expenditures as current expenses is the same as any other allowing premature deductions; the tax payer is allowed to defer current tax liabilities; this treatment amounts to an interest-free loan. The estimated impact of this special tax provision in terms of tax revenue loss by the U.S. Treasury is shown in the chart below.

Estimated Revenue Loss
(In Millions of Dollars)

<u>Fiscal Year</u>	<u>Individuals</u>	<u>Corporations</u>	<u>Total</u>
1977	195	840	1,035*
1976	155	650	805
1975	120	500	620

* Jane Gravelle, et al., Tax Expenditures: Compendium of Background Material on Individual Provisions, Prepared for U.S. Senate Committee on the Budget, March 17, 1976, p. 27.

These expensing provisions are additional benefits which supplement the special percentage depletion allowance extended to the mineral industry. Although the expensing and depletion provisions operate somewhat independently, a firm or person may be eligible for both and receive their combined benefits.

3. U.S. tax credit for payments to foreign governments: In addition to the tax benefits already mentioned, a foreign tax credit is alleged to provide special benefits for oil producers. Starting with the Revenue Act of 1918, the U.S. has allowed a foreign tax credit against income derived from foreign sources. This foreign tax credit has been particularly useful to the major oil companies who have historically accounted for almost half of the credits claimed by U.S. corporations. This credit is important because it is applied dollar for dollar against U.S. tax rather than the usual 48% for each dollar deduction applied to gross income as reported.

The impact of the tax treatment of oil and gas companies' earnings abroad can be measured in terms of annual revenue lost by the U.S. Treasury in three general areas:^{1/}

1/ Energy Taxation: Possible Modifications in the Tax Treatment of Foreign Oil and Gas Income, prepared by the Staff of the Joint Committee on Internal Revenue Taxation, February 21, 1974. (These dollar estimates are based on conditions existing during the early 1970's.)

- (1) Allowance of percentage depletion (more technically, the excess of percentage depletion over cost depletion) . . . approximately \$50 million annually
- (2) The use of excess foreign tax credits on income from oil and gas production to offset U.S. tax on other foreign source income. . . approximately \$300-\$400 million annually.
- (3) The deducting of foreign development costs against U.S. source income. . . approximately \$150 million annually.

4. Summary: The oil and gas industry are subject to special tax provisions which create benefits in at least the three ways described. First, the provisions allow, through the percentage depletion additional deductions beyond the recovery of costs, and thus reduce taxes. Second, the provisions allow the acceleration of deductions for the cost of capital assets and thus defer taxes. And thirdly, the use of foreign tax credits reduces the U.S. tax liability by an amount equal to the taxes paid foreign countries.

B. Legislative History

This section outlines the history of the special tax provisions. It also specifies the tax rate at the time of enactment for both individuals and corporations (when possible) to illustrate the increased importance of the special provisions due to current higher tax rates, as well as the revision of the provisions themselves.

1. Depletion allowance:^{1,2/} No allowance was made for depletion or for depreciation until the enactment of the 16th amendment in the 1913 law which established federal income tax. This provision allowed for reasonable deductions for exhaustion, wear and tear of property, in the case of mines not to exceed 5% of gross value of output.

The first major revision occurred in 1915 (the Revenue Act) in the allowance of depletion to be used at fair market value within 30 days of discovery. The most important aspect of discovery depletion was that it allowed deductions in excess of original cost.

1/ Agria, Susan, "Special Tax Treatment of Mineral Industries." in The Taxation of Income from Capital, The Brookings Institution, Washington, D.C., pp. 77-122 (1969).

2/ U.S. Congress, Senate Committee on Interior and Insular Affairs, An Analysis of the Federal Tax Treatment of Oil and Gas and Some Policy Alternatives, 58 pages (1974).

In 1924, the depletion allowance was revised to limit deductions to 50% of net income from property. A further revision accompanied the Revenue Act of 1926 when a 27.5% depletion rate was adopted. This rate remained relatively unchanged until 1969. (Note at the time of its passage (1926), statutory tax rates for corporations were 13.5%; and ranged from 1.125 to 25% for individuals.)

In 1932, a provision was added requiring the basis of cost depletion to be reduced by any percentage depletion taken. In 1954, a provision allowing aggregation of mineral interests within an operating unit for purposes of the 50% of taxable income limitation was adopted.

The 1969 Tax Reform Act made several changes affecting depletion. Its major revision was the reduction of the depletion rate to 22%. In 1970 excess depletion was made subject to the minimum tax. (Note, at the time these revisions in the tax laws were made, statutory tax rates for corporations were 48%, and ranged from 14 to 70% for individuals.) This was further revised in 1975 as already described earlier.

The House Report accompanying the Tax Reform Act of 1969 described the change to depletion allowance in the following manner.^{1/}

"... committee believes that even if percentage depletion rates are viewed as a needed stimulant at the present time, they are higher than is needed to achieve the desired beneficial effect on reserves."

"Your committee believes that there is a need to strike a better balance than now exists between the objectives of encouraging the discovery of new reserves and the level and revenue cost of percentage depletion allowances. The present 27.5% percentage depletion rate for oil and gas wells was set in 1926 when tax rates were substantially lower than at present. As a result, the tax-inducement granted by this percentage depletion is substantially greater than it was in 1926."

2. Expensing of intangible drilling, exploration, and development costs;^{2,3/} The option to expense intangible drilling costs (as well as dry

^{1/} U.S. Congress, Committee on Ways and Means, report on the Tax Reform Act of 1969. 91st Congress, 1st Session, House Report 91-413, pt. 1, p. 137 (1969).

^{2/} Agria, op.cit., pp. 77-122.

^{3/} U.S. Congress, Senate Committee on Interior and Insular Affairs, An Analysis of the Federal Tax Treatment of Oil and Gas and Some Policy Alternatives, 58 pages (1975).

hole costs) of oil and gas wells developed through regulations issued in 1917.^{1/} The regulations reflected the view that such costs were ordinary operating expenses. In 1942, the Treasury Department recommended that the provisions be removed, but Congress did not consider the suggestion.^{2/} In 1945, when a court decision invalidated the regulations,^{3/} Congress adopted a resolution^{4/} approving the treatment and later incorporation into law in the 1954 code. The legislative history of this resolution indicates the tax provision was intended to reduce uncertainty in mineral exploration and stimulate drilling for military and civilian purposes.^{5/} Expensing of mine development expenditures was enacted in 1951 to reduce ambiguity in current tax treatment and encourage extraction. A provision for exploration was added in 1966.

Prior to the Tax Reform Act of 1969, a taxpayer could elect either to deduct without dollar limitation exploration expenditures in the United States, which subsequently reduced percentage depletion benefits, or to deduct up to \$100,000 a year with a total not to exceed \$400,000 of foreign and domestic exploration expenditures without the application of the recapture rule. The 1969 Act subjected all post-1969 exploration expenditures to recapture.

3. Foreign tax credit:^{6/} The first foreign tax credit was allowed for foreign income, war, and excess profits tax in the Revenue Act of 1918 for the purpose of alleviating the burden of high foreign taxes.

The original act of 1913 allowed foreign income taxes to be deducted but not credited. There were no limits to the credit, allowing the amount of foreign income taxes as a deduction reducing U.S. taxes on domestic income. The Revenue Act of 1921 provided an offsetting limitation on domestic income against which foreign taxes could be applied.

The Revenue Act of 1932 added a per country limitation, so taxpayers were subject to two limits on foreign tax credits. In addition, prior to 1932 any taxes which could not be credited under the foreign tax

^{1/} 19 Treas. Dec., Int. Rev. 31 (1917).

^{2/} Hearings on Revenue Revision of 1942 before the Committee on Ways and Means, p. 2996, Vol. 3, 77th Congress, 2nd Session.

^{3/} FHE Oil Co. vs. Commissioner, 147 F.2d 1002, 5th Cir. (1945).

^{4/} H. Con. Res. 50, 79th Congress, 1st Session.

^{5/} H. Rep. No. 761, 79th Congress, 1st Session, pp. 1-2.

^{6/} Agria, op cit., pp. 77-122.

credit procedures were allowed as a deduction, thereby reducing the tax liability on domestic income. The 1932 act disallowed any deduction of the credit taken. (Note in 1932 individual tax rates were up to 63%, and the corporate tax rate was 13.75%.)

The Revenue Act of 1942 added a provision allowing taxes in lieu of income taxes to be included in the foreign tax credit. This action was taken because some countries tended to impose excise rather than income taxes.

In 1950, the Treasury recommended removal of the overall limits on the grounds that it reduced allowable taxes if losses were sustained in one country and created barriers to investment.

The Technical Amendments Act of 1958 introduced a 2-year carry-back and 5-year carry-forward. The provisions were included in the House report which indicted that loss of credits occurred because of different reporting requirements.

In 1960, a separate bill was passed (P.L. 86-780) allowing taxpayers to choose between the overall and per-country limitation. (Note at this time, and in 1958, the maximum statutory individual income tax rate was 91% and the corporate income tax rate 52%.)

4. Summary: All of these provisions date back to the earliest income tax laws. In view of the greatly increased tax rates for corporations and the development of higher foreign taxes, these provisions account for a much larger benefit in present times than at the time they were enacted. A deduction currently reduces tax liability for corporations 48¢ on the dollar; in 1926 it would have reduced tax liability 13.75¢; in 1918 it would have reduced tax liability 2¢ on the dollar.

C. Quantitative Studies

Relatively little quantitative information concerning the impact of special tax provisions for the energy industry exists. The available studies attempt to evaluate and quantify the dollar impact in revenue loss to the U.S. Treasury of (1) percentage depletion, and (2) intangible drilling expense. A more comprehensive review of such studies was prepared in 1974 by Dunn and Gravelle.^{1/}

^{1/} U.S. Congress, Senate Committee on Interior and Insular Affairs, An Analysis of the Federal Tax Treatment of Oil and Gas and Some Policy Alternatives (1974).

The first major quantitative study--the CONSAD report^{1/}, prepared in 1968--estimated the effects of tax incentives. It attempted to measure the impacts of repealing percentage depletion and expensing of intangibles. The study utilized an industry simulation mode and concluded that the existing tax provision had little impact on oil reserves, and that \$1.4 billion in revenue loss through these special tax provisions yielded \$150 million in reserve additions.^{2/}

A second more detailed study was prepared by Spann, Erickson, and Millsap.^{3/} This analysis of the impacts of these special tax provisions was based on existing estimates of supply responsiveness in the petroleum industry.^{4/} Their model allowed production and the reserve ratio to vary along with the supply of reserves, thus avoiding some of the criticisms of the CONSAD study. They measured the effects of removing percentage depletion and the expanding intangible expenses, assuming in one case a constant ratio of imports with increased prices, and in the other, imports sufficient to keep the prices constant. They found a substantial impact of tax provisions in terms of inefficiency in the allocation of resources, which they estimated at \$306.5 million. The results also suggested the per barrel cost of an emergency storage reserve would be less than the cost of additional reserves and production encouraged by tax provisions, if the goal of the provisions was to provide for national security.^{5/}

It should also be noted that the results are dependent upon the data and methodology used, including critical assumptions concerning supply and demand elasticity. Thus the estimates are subject to dangers associated

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- 1/ CONSAD Research Corporation, The Economic Factors Affecting the Level of Domestic Petroleum Reserves, pt. 4 of the U.S. Congress Committee on Ways and Means, and Senate Committee on Finance, Tax Reform Studies and Proposals, U.S. Treasury Department, Washington, Government Printing Office (1969).
 - 2/ The CONSAD data and methodology have been subject to strong criticism by several industry sources, the main (or most serious) criticism being that production was held constant.
 - 3/ Robert M. Spann, Edward Erickson, and Stephen W. Millsaps, "Percentage Depletion and the Price and Output of Domestic Crude Oil," in U.S. Congress, House Ways and Means Committee, panel discussions on general tax reforms, Panel 9, Natural Resources, pp. 1309-1328 (February 26, 1973).
 - 4/ The study refers to the estimates by W. V. Meid and P. E. Sorenson in "A National Defense Petroleum Reserve Alternative to Oil Import Quotas," Land Economics, 47(3) (August 1971), which estimated a per barrel cost as low as 9 cents. The study estimated per barrel cost for tax provisions may be as high as 20 to 30 cents a barrel.
 - 5/ Spann, Erickson, Millsaps, op. cit.

with elasticity measures. Elasticity measures are likely to vary depending upon the amount of price increase or decrease being considered. In addition, in using these results for policy purposes, the price constraints deriving from imports may not be so significant as the authors suggested (1) if the price of imported oil increases; (2) if the exporting countries limit supplies, or (3) if prices are administered so as to present no competition with domestic suppliers. The estimate of revenue loss provided in this study--\$2.5 billion--is larger than the CONSAD estimate.

The results of these studies are summarized in Table II. While the different studies fail to derive the same answer, they all do suggest that the cost of the special tax provisions, particularly percentage depletion, may involve tax losses significantly larger than the gain in reserves, production, or both.

III. IMPORT CONTROLS AND NATIONAL SECURITY

A. Description

The benefits provided by import quotas to the petroleum and nuclear segments of the energy industry have been substantial. The impact on the nuclear industry is discussed in Appendix F. The remainder of this section briefly traces the history of the various oil import quota programs and estimates their impacts. Several government-sponsored studies have indicated the direct impacts of such programs on oil costs to range from 25% to 45%.

B. History of Oil Import Quota Schemes^{1/}

Oil import quota schemes have been the subject of controversy among policymakers and economists during the last 3 decades. A landmark in these policy discussions was the Report of the Cabinet Task Force on Oil Import Controls issued in February 1970. This report outlines the nature of the price differential between imported and domestic oil and the size of the subsidies paid by the American consumer in the form of higher costs attributable to the imposition of import quotas.

The first oil import quotas were enacted in the 1930's. Through 1959 these programs were voluntary and generally ineffective. In 1959,

^{1/} Kenneth W. Dam, "Implementation of Import Quotas: The Case of Oil," Journal of Law and Economics, January 1971, pp. 1-60.

TABLE II

QUANTITATIVE STUDIES OF EFFECTS OF REMOVING TAX PROVISIONS ON DOMESTIC OIL PRICES,
PRODUCTION, AND RESERVES (DOLLAR AMOUNTS IN MILLIONS)

<u>Study</u>	<u>Prices</u> <u>(%)</u>	<u>Production</u> <u>(%)</u>	<u>Revenues</u> <u>(%)</u>	<u>Value of</u> <u>Production</u> ^{a/}	<u>Tax</u> <u>Revenue</u> <u>Loss</u>
1. CONSAD Research Corp., 1968, for years 1950-1965					
Percentage Depletion	N.A. ^{b/}	N.A. ^{c/}	-3.0	---	\$1,200
Intangible Drilling Costs	N.A.	---	-1.9 - 4.0	---	\$119 - 324
Both	N.A.	---	-7.0	---	\$1,400
2. Spann, Erickson, and Millsaps, 1973, for year 1971					
Percentage Depletion	9.0	(-4.3) - (-11.4)	(-11.2) - (-22.5)	\$ 503 - \$1,333	-
Intangible Drilling Costs	14.0	(-6.2) - (-16.3)	(-15.1) - (-31.4)	\$ 725 - \$1,906	-
Both	24.4	(-10.5) - (-26.0)	(-24.4) - (-36.0)	\$1,227 - \$3,040	\$2,500

a/ Dollar values for the Spann, et al. study were computed by multiplying the value of U.S. crude oil production (BOM) by the percentage change in respective estimates of production.

b/ Prices were held constant.

c/ Production was held constant.

the Mandatory Oil Import Quota Program^{1/} was enacted. This program was established on the grounds "that crude oil and the principal crude oil derivatives and products are being imported in such quantities and under such circumstances as to threaten to impair the national security." The program's objective was to eliminate U.S. dependence on foreign oil supplies. Its goal was to encourage the domestic oil industry to locate and develop domestic resources through a series of import restrictions. In addition, it was "to prevent imports from causing a decline that would so weaken the national economy as to impair the national security."

The Mandatory Program contained two separate regionally-administered schemes: one for that portion of the U.S. east of the Rockies; the other for the portion west of the Rockies.

The administrative policies concerning the quotas ("tickets") were allocated as a percent of refinery inputs, subject to two modifications, a swap arrangement and a finagle factor. These modifications could be manipulated through use of (1) a sliding scale; (2) historical minimums; (3) exchanges or manipulations of allocation computations. These procedural elements become further complicated with a web of "exemptions" and "preferences" that would delight lawyers and confound the public. For example, overland shipments from Canada or Mexico formed a quota exemption.

During the summer of 1973, two significant events altered U.S. oil import control programs. First, a presidential announcement ended the Mandatory Oil Program. A few months later the Middle East war erupted and the U.S. was held at political bay by the world's oil producers.

C. Quantitative Studies

Only two studies have attempted to estimate the social and subsidy costs associated with the Mandatory Oil Program. Each evaluation calculated the added costs paid by U.S. consumers to domestic oil companies attributable to these artificial import controls.

^{1/} Many attribute the U.S. refining shortage and political vulnerability to the Mandatory Oil Import Quota program. There are two lessons to learn. First, the costs of society when government enters into a market and reduces competition may be far greater than the wedge in relative prices that it creates. Lost jobs, a reduced national security posture, the lack of adequate refining capacity are the additional factors which can be attributed to this program. Secondly, the whole world is paying a higher price for oil in part due to the lack of competition created by the program.

The first study^{26/} performed in the early 1960's by the President's Petroleum Study Committee and later updated by Resources for the Future calculated the Mandatory program increased oil prices approximately \$1.00/barrel. At consumption rates existing during the later 1960's, this amounted to a \$3.5 billion subsidy paid by U.S. consumers. This translates into a 25% subsidy in the form of added consumer prices paid to the domestic oil companies.

A 1973 study by Cicchetti and William Gillen^{27/} calculated both social and subsidy costs in 1970 associated with the Mandatory Oil Import Quota Program to be \$224 billion, and \$720 billion, respectively. The social costs contained two components reflecting the economic inefficiency (or mis-allocation of resources) caused by the quota program.

Component One consisted of those costs of supplying the quantity consumed with the quota system in effect over the cost for the same quantity which would have been imported at a lower price. This equates those costs equal to the amount of resources that are needlessly expended to produce the same quantity of crude oil.

Component Two calculated the social costs incurred from foregone consumer surplus. It calculated the cost of increased consumption that would have resulted if oil prices had been competitive. This is a lost opportunity cost to society.

The size of the subsidy was estimated in added consumer prices paid to domestic oil companies and calculated as the cost differential per barrel between domestic and foreign oil prices multiplied by total domestic consumption.

26. A Report to the President, by the Petroleum Study Committee, op. cit, 1968.

27. Chicchetti, Charles J., and William Gillen, "The Mandatory Oil Import Quota Program: A Consideration of Economic Efficiency and Equity," in The Economics of Federal Subsidy Programs, U.S. Congress, Joint Economic Committee, Washington, U.S. Government Printing Office, p. 1013.

IV. DIRECT FEDERAL SUBSIDY PROGRAMS

The federal government has actively supported the development of several energy industry segments. For example, the nuclear power industry has been directly or indirectly subsidized since 1946. The history of the hydroelectric industry serves as another example illustrating how government subsidies have supported the development of a segment of the energy industry. In both cases--government agencies (e.g., the AEC, ERDA, TVA, Department of Interior, etc.) have initiated programs aimed at (1) obtaining the basic scientific and engineering data needed for proof of technical feasibility and safety; (2) demonstrating the actual economic feasibility of each type of electricity generator; (3) funding and/or performing industry R&D; and (4) purchasing, constructing or operating facilities for several industry segments.

The case history of the nuclear industry in Appendix F illustrates the dependence of the industry on governmental subsidies.

The present development of the hydroelectric industry has been the direct result of the federal government's direct support of the industry. Since 1909 the government has constructed and operated the major hydroelectric facilities in the United States.

V. ANNOTATED BIBLIOGRAPHY

This is an expansion of the annotated bibliography prepared by Ms. Jane Gravelle and Dr. Leroy Dunn of the Congressional Research Service for the 1974 Senate study "An Analysis of the Federal Tax Treatment of Oil and Gas and Some Policy Alternatives."

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This statement discusses the impact of tax provisions on industry structure and the effect of these provisions on foreign versus domestic production.

American Petroleum Institute, Division of Taxation, Comment on the Erickson-Millsaps Paper published by the Joint Economic Committee, July 15, 1972, Hearings, Tax Subsidies and Tax Reform before the Joint Economic Committee, 92nd Congress, 2nd Session, July 19-21, 1972, Washington, U.S. Government Printing Office, p. 271 (1973).

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This report examines the impact of the Mandatory Oil Import Quota Program in terms of both its social and subsidy costs. Its evaluation analyzes the economic inefficiency or misallocation of resources caused by this program.

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Dam presents a comprehensive discussion of the historical, legal and political aspects of the Mandatory Oil Import Quota Program.

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This study updated estimates of supply elasticity in petroleum, originally presented by Fisher in Supply and Costs in the U.S. Petroleum Industry: Two Econometric Studies. Johns Hopkins Press, Baltimore (1964).

Erickson, Edward W., and Stephen W. Millsaps, "Taxes, Goals and Efficiency: Petroleum and Defense," The Economics of Federal Subsidy Programs. A Compendium of Papers Submitted to the Joint Economic Committee, July 15, 1972, Washington, U.S. Government Printing Office, pp. 286-304, (1972).

The authors examine the arguments for percentage depletion and expensing of the CONSAD report suggesting that the report understated the effect of this treatment. They suggest that there may be less costly methods of dealing with the national defense objective. The article also includes a critique of the CONSAD report suggesting that the report understated the effect of the provisions on reserves.

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This brief background paper describes percentage and cost depletion, intangible drilling cost deductions, and the foreign tax credit, and summarizes the arguments commonly made for and against them.

Gravelle, Jane, et al., Tax Expenditures: Compendium of Background Material on Individual Provisions. Committee Print, Senate Committee on the Budget, 94th Congress, 2nd Session, March 17, 1976, Washington, U.S. Government Printing Office, pp. 27-37 (1976).

This compendium of summaries describing the operation and impact of each tax expenditure indicates the authorization and rationale for its enactment and perpetration; estimates both the revenue loss attributable directly, the percentage distribution by adjusted gross income class of the tax savings conferred by the provision; and cites selected bibliography for each provision.

Hambrick, J. Reid, The Elimination of Double Benefits in the Income Tax Treatment of Oil and Gas Production: Four Modest Proposals. Panel discussions on general tax reform, Panel No. 9: Natural Resources, U.S. Congress, House Committee on Ways and Means, February 26, 1973, Washington, U.S. Government Printing Office, pp. 1367-1375 (1973).

This statement suggests reform in four areas--the rate of percentage depletion, intangible drilling costs, the treatment of tangible well equipment, and the foreign tax credit.

Harberger, Arnold C., The Taxation of Minerals Industries, in U.S. Congress, Joint Committee on the Economic Report, Federal Tax Policy for Growth and Stability, Washington, U.S. Government Printing Office, pp. 439-449 (1955).

The author argues that the special provisions for the oil and gas industry create non-neutrality with respect to oil and gas and misallocates resources to the oil and gas industry. Until recently, the tax neutrality question figured prominently in the debate over the tax treatment of oil and gas. For other contributors to this literature see citations under Agria, Campbell, Davidson, McDonald, Eldridge, Musgrave and Steiner.

Johnson, William A., Special Assistant to the Deputy Secretary on Energy and Natural Resources, Treasury Department. Testimony before the House Ways and Means Committee, December 4, 1973 (hearings not printed).

This statement discusses various alternatives for dealing the current energy shortage, including price rises, deregulation of natural gas, gasoline taxes, rationing. The percentage depletion allowance and possible excess profits taxes are also discussed.

Litchblau, John H., Some Comments on the differential tax treatment of the petroleum producing industry, in Proceedings of Rocky Mountain Petroleum Economic Institute, June 25-28, 1967, pp. 39-52.

Litchblau argues in favor of the tax provisions that removal of percentage depletion might adversely affect marginal wells and that the overall tax burden on oil and gas is the same or higher than other industries. He suggests that intangible drilling costs deduction has been more important for purposes of national security.

McDonald, Stephen L., Federal Tax Treatment of Income From Oil and Gas, Brookings Institution, Washington (1963).

A general background paper prepared for a conference of experts held in 1962, together with a summary of the conference discussion. Selected bibliography on pages 155-158.

McDonald, Stephen L., Percentage depletion and tax neutrality: a reply to Messrs. Musgrave and Eldridge, National Tax Journal, 15 (3):314-326 (September 1962).

McDonald responds to criticisms of Musgrave and Eldridge, arguing his purpose was not to deal generally with the neutrality of the corporate tax but to challenge the argument that percentage depletion creates non-neutrality. While he admits problems with the empirical base of his argument, he retains his general conclusions.

McDonald, Stephen L., Percentage Depletion and the Allocation of Resources: The Case of Oil and Gas, National Tax Journal, 14 (4):323-336 (1961).

McDonald challenges the proposition made by Harberger and others that the special tax provisions for oil and gas create non-neutrality. He argues that special provisions are consistent with neutrality because they apply to a risky, capital-intensive industry.

Mid-Continent Oil and Gas Association, "Analysis and comment relating to the CONSAD report on the influence of U.S. petroleum taxation on the level of reserves." Tax reform, 1969 hearings before the Senate Finance Committee, 91st Congress, 1st Session, Part 5 of 7 parts, pp. 4627-4647 (1969).

This critique of the CONSAD report charges that the conclusions of the report are invalid because the model is inappropriate, the quality and manipulation of the data questionable, the report contains factual errors and the study uses doubtful promises about the economies of the petroleum industry. The critique also notes that the numerous cautions made by CONSAD itself suggests that the results should not be accepted without further inquiry. One of the most serious criticisms appears to be the holding of production constant.

Musgrave, Richard A., Another look at depletion, National Tax Journal, 15 (2):205-208 (June 1962).

Musgrave criticizes McDonald's thesis that the percentage depletion allowance acts to restore neutrality. He suggests that the argument is overstated due to the assumption that capital is perfectly inelastic.

Natural Resources Journal, 10 (1) (January 1970).

This issue presents a symposium on Federal treatment of oil production. The symposium includes contributions by Paul Davidson, John Due, Edward W. Erickson, Alfred E. Kahn, Wallace F. Lovejoy, Stephen McDonald and Walter Mead.

Nixon wildcat "incentives" curtail the search instead, Oil and Gas Journal, pp. 19-22 (June 14, 1973).

This article criticizes administration proposals made in April 1973, including a credit for exploratory drilling. The article charges that the definition of exploratory wells is too narrow.

Peach, W.N., The Energy Outlook for the 1980's. A Study Prepared for the Use of the Subcommittee in Economic Progress of the Joint Economic Committee (December 17, 1973).

This study examines the outlook for developing energy resources in the United States including coal, off-shore oil and gas, Alaskan oil and gas, oil shale, nuclear energy, geothermal energy, and tar sands.

Peel, Fred W., Corporations and the 10 percent "minimum" tax. The Tax Executive, 23 (4):588-596 (July 1971).

The author charges that large integrated corporations are better able to avoid the minimum tax because they are more likely to have regular income taxes to offset preferences. He deals specifically with percentage depletion.

Petroleum Industry Research Foundation, Inc., The Tax Burden in the Domestic Oil and Gas Industry (May 1972).

This pamphlet compares total taxes (federal, state, and local) as a percentage of gross income and value added of the oil and gas industry with that paid by other business.

Price-Waterhouse and Company, "Statistical Data for Selected Petroleum Companies Compiled for Use in Analysis of Taxes and Effective Federal Income Tax Rates, Year 1970.

This aggregation of data prepared for the American Petroleum Institute is based on confidential information supplied by 18 major oil companies. It includes data on tax versus book depletion, depreciation, and intangible drilling costs deductions, divided into foreign and domestic expenditures on exploration and development, taxes paid to state, local, and foreign governments, and other items.

Spann, Robert M., Edward W. Erickson and Stephen W. Millsaps, Percentage Depletion and the Price and Output of Domestic Crude Oil, Panel discussions on general tax reform, Panel No. 9: Natural Resources, U.S. Congress, House Committee on Ways and Means, 93rd Congress, 1st Session, Washington, U.S. Government Printing Office, pp. 1309-1328 (1973).

This study, using a supply and demand analysis attempted to measure the effect of percentage depletion and intangible drilling costs on prices, productions and reserves.

Stauffer, Thomas R., Economic cost of U.S. crude oil production. Journal of Petroleum Technology, pp. 643-57 (June 1973).

This study estimated the impact on production of removing the percentage depletion allowance, intangible drilling cost expensing and expensing of dry holes and various combinations of these provisions. The study examined what portion of production would become uneconomic because of revenue loss from the provision.

Steiner, Peter O., The non-neutrality of corporate income taxation--with and without depletion. National Tax Journal, 16(3):238-251 (1963).

Steiner reviews the tax neutrality debate regarding percentage depletion (see Eldridge, Harberger, McDonald, Musgrave, and Steiner.) He suggests that neutrality is not a sacred principle and that sound national policy may find overriding reasons for reallocating resources.

Steiner, Peter O., Percentage depletion and resource allocation, in Tax Revision Compendium, U.S. Congress, House Committee on Ways and Means, Washington, U.S. Government Printing Office, pp. 949-966 (1959).

Steiner suggests that tax provisions regarding oil and gas cause non-neutrality in the tax system, but finds reallocation of resources to be less than that suggested by Harberger.

Stone, Lawrence M., Taxation of Foreign Income, in Panel discussions on tax reform, Panel No. 11, Taxation of Foreign Income, U.S. Congress, House Committee on Ways and Means, 93rd Congress, 1st Session, February 28, 1973, pp. 1835-1841 (1973).

This statement on the tax treatment of foreign income in general also deals specifically with the tax benefits to foreign exploration and development of natural resources including the deduction of percentage depletion and intangible drilling costs and the crediting of royalties as foreign income taxes.

Taxation with Representation. Compendium prepared for the House Committee on Ways and Means and the Senate Committee on Finance, regarding the petroleum industry's tax burden, 1973. In U.S. Congress, House Committee on Ways and Means, hearings on general tax reform, March 19-20, 1973, Washington, U.S. Government Printing Office, pp. 2295-2358 (1973).

This compendium examines data from U.S. Oil Week and that compiled by Price-Waterhouse for the American Petroleum Institute and the Petroleum Industry Research Foundation, Inc. Compendium statements include "The Economics of the Oil Industry's Tax burden," by James C. Cox and Arthur W. Wright; "Taxation and the Petroleum Industry," by Edward W. Erickson, David M. Hyman, Robert M. Spann and Stephen W. Millsaps; and "Tax Payments by the

Petroleum Industry," by an attorney who has specialized in tax matters and submitted his comment under the pseudonym "Agricola" since his employment would make it awkward to submit a comment under his own name. Senator Proxmire's insertion into the Congressional Record of the U.S. Oil Week Data, October 27, 1971, and a letter from Frank Ikard of the American Petroleum Institute submitting the Price-Waterhouse data and the Petroleum Industry Research Foundation, Inc. study to Congressional offices are reprinted. Taxation with Representation is a public interest tax lobby.

Tussing, Arlon R., Discussion of "estimated economic cost of U.S. crude oil production," by Thomas R. Stauffer, Journal of Petroleum Technology, pp. 657-658 (June 1973).

This critique was not specific to the section of the paper dealing with taxation since the author felt the methodology to be unclear. He questioned whether Stauffer was examining the impact on average cost wells or high cost wells.

U.S. Congress, House Committee on Ways and Means, Legislative History of Depletion Allowances, prepared by the staff of the Joint Committee on Internal Revenue Taxation, 36 pages (March 1950).

This legislative history presents the early development of the depletion allowance in detail.

U.S. Congress, Joint Economic Committee, The Economics of Federal Subsidy Programs, Part 3 - Tax Subsidies, prepared by the committee staff, 405 pages (July 15, 1972).

This compendium of papers deals with benefits that are transferred through special effects of tax incentives on business investment.

U.S. Congress, Senate Committee on Finance, Fiscal Policy and the Energy Crisis, Subcommittee on Energy, Committee Print, 93rd Congress, 1st Session, Washington, U.S. Government Printing Office, November 20, 1973.

This committee print contains briefing materials on the use of fiscal policy to deal with the energy crisis.

U.S. Congress, Senate Committee on Interior and Insular Affairs, Financial Requirements of the Nation's Energy Industry, Serial No. 93-5, March 6, 1973. 93rd Congress, 1st Session, Washington, U.S. Government Printing Office (1973). Submissions of the Federal Power Commission, pp. 218-219, Department of the Interior, pp. 225-233, and the Treasury Department, pp. 234-249.

These statements were solicited in regard to the capital needs of the petroleum industry. Of particular interest are the discussions of the Treasury Department regarding the effects of percentage depletion, expensing of intangibles, and dry hole costs.

U.S. Treasury Department, Proposals for Tax Change, April 30, 1973 (presented before the Ways and Means Committee Hearings on tax reform).

This proposal of the Treasury Department included a tax credit for exploratory drilling.

U.S. Treasury Department, Staff Analysis of the Preliminary Federal Trade Commission Staff Report on its Investigation of the Petroleum Industry, July 2, 1973, Senate Committee on Interior and Insular Affairs, Committee Print, Serial No. 93-98, 1973 (letter of transmittal dates August 29, 1973).

This analysis refutes the charges made by the Federal Trade Commission regarding the effect of tax and other conditions on concentration in the petroleum industry.

U.S. Treasury Department, Tax Reform Studies and Proposals, U.S. Congress, House Committee on Ways and Means and Senate Committee on Finance, Washington, U.S. Government Printing Office, pp. 413-433 (1969).

A summary of the issues with regard to tax treatment of minerals and an evaluation of the Fisher-Erickson and CONSAD estimates.

Wheatley, Charles F., Statement in U.S. Congress, Senate Committee on Interior and Insular Affairs, February 25, 1969, and March 2, 1972, Serial No. 92-22, Part 2, pp. 770-772 (1972).

This section of Wheatley's testimony deals with the effect of federal income taxation on natural gas prices and production.

World Oil Developments and U.S. Import Policies, A Report Prepared by the U.S. Tariff Commission, U.S. Congress, Senate Committee on Finance (December 17, 1973).

An analysis of the questions of substituting tariffs for quotas to control oil imports.

APPENDIX H

EXTENSION OF THE HOTTEL-WHILLIER-BLISS MODEL TO THE ANALYSIS OF COMBINED PHOTOVOLTAIC/THERMAL FLAT PLATE COLLECTORS

EXTENSION OF THE HOTTEL-WHILLIER-
BLISS MODEL TO THE ANALYSIS OF
COMBINED PHOTOVOLTAIC/THERMAL FLAT
PLATE COLLECTORS

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Abstract - The well known Hottel-Whillier-Bliss model for thermal analysis of flat plate collectors is extended to the analysis of combined photovoltaic/thermal collectors in a manner, such that, with simple modification of the conventional parameters of the HWB model, all of the existing relations and supporting information available in the literature still apply. Beyond the basic assumptions of the original HWB model, it is only necessary to assume that the local photovoltaic cell conversion efficiency is a linear decreasing function of the local cell temperature over the operating temperature range of the combined collector. Based on the extended model, examples of both thermal and electrical performance of the combined collector as a function of collector design parameters are presented and discussed.

INTRODUCTION

Current interest and activity in photovoltaic systems for terrestrial applications are expanding rapidly. This includes the investigation and development of hybrid or combined thermal/electric flat plate collectors in which the absorber consists of an array of solar cells for generation of electricity, while collector fluid circulating past the absorber also provides useful thermal energy as in a conventional flat plate collector.

A model for thermal analysis of conventional flat plate collectors which generally provides an excellent compromise between simplicity and accuracy in application is that originally developed and presented by Hottel and Woertz [1], Whillier [2], and Hottel and Whillier [3], and later amplified in certain respects by Bliss [4]. In addition to its familiarity to workers in the solar energy field, this model is commonly employed in solar energy system simulation programs utilizing hi-speed digital computers (e.g., the TRNSYS program developed at the University of Wisconsin [5]). Furthermore, much supporting information as to values of parameters for use with the HWB model already exists in the literature. In addition to the references already cited, Whillier [6] and Duffie and Beckman [7] may be consulted in this regard.

It is the purpose of this paper to show how the application of the HWB model can be extended to the analysis of combined thermal/electric

flat plate collectors in a simple but rigorous manner which permits direct utilization of the existing supporting information and relations of the HWB model. Beyond the basic assumptions implicit in the conventional HWB model, it is only necessary to assume that the local solar cell electrical conversion efficiency can be represented as a linear decreasing function of the local cell (absorber) operating temperature. This is quite reasonable over the operating temperature range of a given flat plate collector. The usual parameters of the HWB model are modified in a simple way, the modifications depending on two cell parameters, one of which specifies the cell reference efficiency while the other specifies the decrease of cell efficiency with temperature.

The development of the necessary relations is presented below, along with a discussion of their implications and several parametric curves illustrating the effect of both the thermal design and the cell characteristics on the thermal and electrical performance of the collector.

ANALYSIS

The basic assumptions and developments of the conventional HWB model are thoroughly reviewed in the recent book by Duffie and Beckman [7], and therefore will not be repeated here except as necessary to develop the method of extension to the combined collector. For the convenience of the interested reader, the extended analysis is outlined for a tube and sheet collector configuration like that initially considered on p. 139 of this readily available reference text. For the same reason, the basic notation of that work is also utilized.

The configuration is depicted in cross-section normal to the collector fluid flow direction in Fig. 1. The solar cells are bonded to the surface of the plate. This cell/plate composite will be referred to as the absorber. The underside of the plate and tubes is well insulated. A local energy balance is to be written for an element of the absorber as indicated in Figs. 1 and 2. As in the conventional HWB model, it is assumed that temperature gradients in the absorber transverse to the direction of fluid flow (x-direction in Fig. 1) can be treated independently of those parallel to the flow direction. The element dx by δ is therefore initially considered to have unit depth in the flow direction with no energy transfers occurring across the faces normal to the flow direction. Furthermore, temperature gradients across the absorber thickness are neglected. This is quite acceptable in a conventional collector since the thermal resistance across the plate thickness is negligible compared with that between the plate and ambient. Since, for a combined collector, the cell thickness will be very small relative to the plate thickness the assumption will remain valid as long as the thermal resistance across the cell/plate bond is negligible. The largest value this resistance might be is of the order of $0.001 \text{ m}^2 \cdot \text{K/W}$ [8]. The smallest absorber-to-ambient thermal resistance would occur for an unglazed collector,

Fig. 1 Cross-section of tube and sheet configuration for illustration of combined collector analysis.

Fig. 2 Local energy balance on the absorber of a combined collector of tube and sheet configuration.

with a value of about $0.03 \text{ m}^2 \cdot \text{K/W}$ for a 5 m/s wind. Thus, the neglect of temperature gradients across the absorber (cell/plate composite) remains valid for the combined collector. The steady-state energy balance indicated in Fig. 2 then results in

$$\frac{d^2T}{dx^2} = \frac{1}{k\delta} [U_L (T-T_a) - S + q_e], \quad (1)$$

where the original assumption of the HWB model that the local thermal loss q_L , is proportional to the difference between the local absorber temperature, T , and the ambient temperature, T_a , has been retained. Setting $q_e = 0$ in eqn (1) reduces it to that for a conventional thermal collector without cells,

$$\frac{d^2T}{dx^2} = \frac{1}{k\delta} [U_L (T-T_a) - S]. \quad (2)$$

Now defining the cell efficiency, η , in the usual manner as the ratio of the electrical output to the incident energy, the local electrical output may be written as

$$q_e = \eta \frac{S}{\alpha} \quad (3)$$

The cell efficiency and therefore the local electrical output may be assumed to decrease linearly with local absorber temperature. Thus,

$$\eta = \eta_r [1 - \beta_r (T-T_r)]. \quad (4)$$

Utilizing eqns (3) and (4) to replace q_e in eqn (1) results with some rearrangement in

$$\frac{d^2T}{dx^2} = \frac{1}{k\delta} [\tilde{U}_L (T-T_a) - \tilde{S}] \quad (5)$$

where

$$\tilde{U}_L = U_L - \frac{S}{\alpha} \eta_r \beta_r = U_L - \tau H_T \eta_r \beta_r \quad (6)$$

and

$$\tilde{S} = S(1 - \frac{\eta_a}{\alpha}) \quad (7)$$

η_a is simply the cell efficiency evaluated from eqn (4) at the ambient temperature, T_a .

Eqn (2) defines the temperature distribution transverse to the flow direction in that portion of the absorber plate of a pure thermal collector between the tubes (the fin). Boundary conditions (see Fig. 1) are a zero temperature gradient at the line of symmetry between two tubes, at $x = 0$, and the temperature, T_b , existing at the first point of contact between the tube and the plate (the fin base), at $x = (W-D)/2$. It is apparent that eqn (5) for the combined collector is identical in form to eqn (2) for the pure thermal collector as

long as U_L and S are replaced by $\tilde{U}_L$ and $\tilde{S}$ as defined by eqns (6) and (7). Consequently, solutions and results based on eqn (2) also apply for the combined collector when, in these solutions and results, U_L and S are similarly replaced by $\tilde{U}_L$ and $\tilde{S}$. This device comes about simply because both the local thermal losses and the local electrical output of the combined collector are assumed to vary linearly with local absorber temperature. However, unlike the thermal losses, which approach zero as the absorber temperature approaches ambient, the electrical output remains finite under the same condition. That is why, not only the thermal loss coefficient, U_L , gets modified, but also the absorbed energy, S .

To complete the illustrative example, the results for the useful thermal gain of the combined collector may be developed based on the form of the results for the pure thermal collector as presented by Duffie and Beckman [7]. The modified collector efficiency factor, $\tilde{F}'$, for the combined collector of tube and sheet design is given by (compare eqn (7.5.17), reference [7])

$$\tilde{F}' = \frac{1}{\frac{1}{F_{WD}} + \frac{\tilde{U}_L}{U_f}} \quad (8)$$

where

$$F_{WD} = (1 - \frac{D}{W}) F + \frac{D}{W}$$

with

$$F = \frac{\tanh[m(W-D)/2]}{m(W-D)/2}$$

and

$$m^2 = \frac{\tilde{U}_L}{k\delta}$$

In eqn (8), U_f represents the total thermal conductance between the absorber temperature over the tube location, T_b , and the local bulk temperature of the collector fluid, T_f , but referred to a unit absorber area.

The form of the analysis for the collector fluid outlet temperature which requires a local energy balance on an element of collector fluid remains the same as presented by Duffie and Beckman. The final extended result for the useful thermal output of the combined collector is (compare eqns (7.7.4) and (7.7.5) in [7])

$$\tilde{Q}_u = A_c \tilde{F}_R [\tilde{S} - \tilde{U}_L (T_{f,i} - T_a)] \quad (9)$$

where the modified collector heat removal factor, $\tilde{F}_R$, is given by

$$\tilde{F}_R = \frac{G c_p}{\tilde{U}_L} [1 - \exp(-\tilde{U}_L \tilde{F}' / G c_p)] \quad (10)$$

It should be emphasized that eqns (9) and (10) are general in the sense that they apply to other absorber/collector-fluid-passage configurations for combined collectors, as well as the tube and sheet design. It is only necessary to use the proper value for the modified collector efficiency factor, F' . Formulas for computing F' for a number of thermal collector designs are summarized by Duffie and Beckman. As was demonstrated for the particular case of the tube and sheet design, these formulas for other designs also apply for computing F' as long as U_L is replaced by $\tilde{U}_L$. It may be noted that a number of these formulas all have the same basic form. For designs in which the absorber temperature distribution transverse to the flow direction is uniform one has

$$\tilde{F}' = \frac{1}{1 + \frac{\tilde{U}_L}{U_f}} \quad (11)$$

where U_f is the total thermal conductance per unit absorber area for the net heat transfer between the absorber and the collector fluid at a given cross-section. If, for example, in a combined collector the cells were mounted on a glass plate which in turn is in contact with the collector fluid, only the cells would be treated as the absorber and U_f would include the effect of the thermal resistance of the glass plate as well as the effect of radiation between the glass plate and the other surface forming the flow passage, and the effect of convection between both surfaces and the collector fluid.

Once the useful thermal output for the combined collector has been determined, it remains to compute the electrical output. This may be expressed initially in terms of an overall energy balance on a combined collector as

$$Q_e = SA_c - \tilde{Q}_u - Q_L \quad (12)$$

Since SA_c may be considered as input information and $\tilde{Q}_u$ is given, in general, by eqn (9) it is only necessary to eliminate Q_L from this expression. The total thermal loss from the collector may be obtained by integration of the local loss over the entire area of the collector. Thus,

$$Q_L = \int_0^{A_c} q_L \cdot dA = U_L \int_0^{A_c} (T - T_a) dA \quad (13)$$

Likewise, the electrical output may be written as

$$Q_e = \int_0^A q_e \cdot dA = \frac{S \eta_r}{\alpha} \int_0^A [1 - \beta_r (T - T_r)] dA,$$

which by adding and subtracting T_a to the temperature difference appearing in the integrand may be manipulated to give

$$Q_e = \frac{S}{\alpha} [\eta_a A_c - \eta_r \beta_r \int_0^A (T - T_a) dA].$$

Solving this equation for the integral, and substituting the result into eqn (13) gives Q_L independently of the temperature distribution. Finally, this result for Q_L along with $\tilde{Q}_U$ from eqn (9) are combined with eqn (12) which may then be solved for Q_e to give

$$Q_e = \frac{A_c S \eta_a}{\alpha} \left\{ 1 - \frac{\eta_r \beta_r}{\eta_a} [\tilde{F}_R (T_{f,i} - T_a) + \frac{\tilde{S}}{\tilde{U}_L} (1 - \tilde{F}_R)] \right\} \quad (14)$$

This result permits direct computation of the electrical output of a combined collector in terms of the conventional parameters relating to the design of a pure thermal collector, plus two cell parameters η_r and β_r . The result also depends, of course, on the ambient temperature, the collector fluid inlet temperature, and through S on the intensity of incident sunlight. Note that η_a is fixed by η_r and β_r through eqn (4) once T_a is specified. The result is simplified somewhat if the reference temperature, T_r , for establishing cell efficiency is specified as the ambient temperature.

DISCUSSION

The quantities F' and F_R for a thermal collector are usually referred to in the literature as the collector efficiency factor and the collector heat removal factor. At a given cross-section of the collector normal to the main flow direction, F' is the ratio of the actual thermal energy gain to that which would occur if the absorber temperature were equal to the collector fluid temperature. $\tilde{F}'$ for the combined collector retains precisely the same interpretation, and therefore depends on the thermal conductance, U_f [see, e.g., eqn (11)].

F_R is just the actual useful thermal output of the collector normalized by the thermal output which would occur were the entire absorber at its lowest possible theoretical temperature, i.e., the collector fluid inlet temperature. The modified parameter $\tilde{F}_R$ retains the same interpretation and is therefore proportional to the collector thermal efficiency. It is in turn dependent on $\tilde{F}'$ [see eqn (10)].

Eqns (10) and (11) were utilized to compute $\tilde{F}'$ and $\tilde{F}_R$ as a

function of the thermal conductance U_f for combined collectors with zero, one, and two glass cover plates. For these computations silicon cells having $\eta_r = 10\%$ at $T_r = 25^\circ\text{C}$ with $\beta_r = 0.0041 \text{ K}^{-1}$ were assumed. The collector fluid capacity rate per unit absorber area, G_{cp} , was fixed at $25 \text{ W/m}^2\cdot\text{K}$. This corresponds to about 4 cfm/ft^2 for air or about 0.5 gph/ft^2 for water. The incident solar radiation level was taken as $H_T = 750 \text{ W/m}^2$. The appropriate values used for other parameters are summarized in Table 1. Corresponding values of F' and F_R

TABLE 1 - Collector Cover System Dependent Parameters Used in Computations

Number of Collector Covers	τ	$U_L [\text{W/m}^2\cdot\text{K}]$
None 5.0 m/s wind	1.0	30.0
None 2.5 m/s wind	1.0	20.0
One	0.92	7.0
Two	0.84	3.5

under identical conditions, except for the absence of the cells, were computed for the case of a pure thermal collector. Values of $\tilde{F}'$ and $\tilde{F}_R$ differ from F' and F_R because of the modified value of U_L given by eqn (6). The largest percentage modification in U_L will occur for the smallest value of U_L , and the largest value of H_T . For the 10% silicon cells, a double glazed collector ($U_L = 3.5 \text{ W/m}^2\cdot\text{K}$), and $H_T = 750 \text{ W/m}^2\cdot\text{K}$, $\tilde{U}_L/U_L$ is 92%. This results in $\tilde{F}'$ and $\tilde{F}_R$ differing from F' and F_R by no more than about 1% for any reasonable thermal designs (say U_f greater than at least $15 \text{ W/m}^2\cdot\text{K}$, see below). It may be concluded that for practical purposes $\tilde{F}'$ and $\tilde{F}_R$ may be considered identical to F' and F_R . This means that all correct results for the latter two quantities to be found in the existing literature remain valid, for practical purposes, for the case of the combined flat plate collector. Obviously, however, this does not mean that the useful thermal output will remain unaffected.

Results from the above calculations for $\tilde{F}_R$ are plotted in Fig. 3. As may be observed, exceedingly large values of U_f are not required for $\tilde{F}_R$ to be within a reasonable percentage of the corresponding asymptotic value, especially for collectors with at least one glazing. For example, for the G_{cp} value assumed for Fig. 3, an air flow through an asymmetrically heated simple parallel plate duct of 4 m length and 1.5 cm wall

spacing results in a value of $U_f = 34 \text{ W/m}^2 \cdot \text{K}$. For the collector with one glazing this puts $\bar{F}_R$ and therefore the collector thermal efficiency at 85% of what would be achieved with an infinite value of U_f . Larger values of U_f could be achieved by narrowing the duct wall spacing or by adding finned surfaces [9] or multiple narrow passages. However, such design approaches must be undertaken carefully since they may increase the pressure drop to unacceptably high values or increase costs for what may be only marginal improvements in performance since the asymptotic limit is already being approached. For water cooled collectors of the tube and sheet type design adequate values of U_f are readily achieved. The curves for unglazed (bare) collectors were included from the standpoint of possible interest in basic photovoltaic collectors which may, in some applications, also be used to provide a moderate amount of preheating to moderate temperatures.

The normalized electrical output as a function of U_f is shown in Fig. 4 for the same conditions as described above and listed in Table 1. The ordinate on this plot is the electrical output from the specified combined collector as calculated from eqn (14), normalized by the output which would occur from an unglazed photovoltaic collector with the cells operating at the lowest possible theoretical temperature, i.e., ambient. For these computations an effective absorptance, α , for the cell array of 0.8 and an ambient temperature of 25°C was assumed, although the normalized results are quite insensitive to these values. The numbers shown adjacent to the curves are the percentages of the asymptotic values of the ordinate for $U_f \rightarrow \infty$. It is apparent from comparing Figs. 3 and 4 that if the thermal design of the collector fluid system results in a value of U_f large enough to provide satisfactory thermal output performance, then very nearly maximum electrical performance for the given set of conditions will be achieved. The degradation in electrical performance of the glazed collectors operating at higher temperatures relative to the bare collectors operating at lower temperatures is also apparent from Fig. 4. The resulting magnitude of this degradation depends on both the transmittance of the glazing system and the difference in operating temperature levels.

As a final point of interest the reduction in thermal performance of a thermal collector due to the addition of solar cells to the absorber is illustrated. The ratio of the thermal output of the combined collector to that of a corresponding pure thermal collector is plotted as a function of the fluid-inlet-to-ambient temperature difference in Fig. 5. These results were computed using a value of U_f of $32 \text{ W/m}^2 \cdot \text{K}$, although it may be emphasized that the ratio $\bar{Q}_u/\bar{Q}_u$ turns out to be essentially insensitive to U_f . This is quite consistent with the fact that it is F_R and $\bar{F}_R$ which depend on U_f , and as has already been noted these do not differ significantly for practical purposes. As indicated in Fig. 5, the reference value $\bar{Q}_u$ was computed for a thermal collector with $\alpha = 0.95$. If one considers adding the nominal 10% silicon cells, a realistic present day value of α for the

Fig. 3 Modified heat removal factors as function of overall absorber-to-collector-fluid thermal conductance for combined collectors of several cover system configurations. See text and Table 1 for parameter specifications.

Fig. 4 Normalized electrical output as function of overall absorber-to-collector-fluid thermal conductance for combined silicon cell collectors of several cover system configurations at specified values of ΔT . Reference value is output of bare collector with cells at ambient. Numbers on curves are percent of asymptotic output. See text and Table 1 for parameters used.

Fig. 5 Useful thermal output of combined silicon cell collector relative to that for pure thermal collector as function of collector-fluid-inlet-to-ambient temperature difference. See text and Table 1 for parameter specifications.

cell-covered absorber might be as low as 0.8. In addition to the reduction in thermal output caused by the extraction of electricity from the absorber, the reduction in α causes a severe penalty in the thermal performance of the collector (see dashed curves, Fig. 5). If the effective absorptance of the cell array could be maintained at or close to the same value as for the pure thermal collector, the penalty in thermal performance due to the addition of cells would not be nearly as severe as indicated by the solid curves in Fig. 5.

CONCLUDING REMARKS

The Hottel-Whillier-Bliss model for analysis of the thermal performance of flat plate collectors has been extended to include the case of combined photovoltaic/thermal collectors. The extension has been carried out in such a way that the thermal performance of the combined collector may be determined in exactly the same way as for a pure thermal collector, except that wherever U_L and S appear in the relevant equations they are to be replaced by the modified values $\tilde{U}_L$ and $\tilde{S}$ as defined by eqns (6) and (7). It may be noted that if the relevant equations are written in terms of H_T instead of S , the replacement of H_T by $H_T(1 - \eta_a/\alpha)$ is equivalent to replacement of S by $\tilde{S}$. The

above approach is valid so long as the cell efficiency can be reasonably represented as a linear decreasing function of cell temperature over the operating temperature range of the collector. To analyze a particular combined collector design, this function must, of course, be known or specified for the cells in question, to establish the cell parameters η_r and β_r .

An expression [eqn (14)] has also been developed for computing the electrical output in terms of the same parameters needed to determine the useful thermal output of a combined collector via the extended HWB model.

The HWB model is already well established and familiar to many workers in the solar energy field. The presented method of extension makes it possible to directly use existing relations and supporting information in the literature relating to the HWB model. In addition, computer simulation routines based on the HWB model can be readily adapted to handle combined collectors. The effects of design alternatives on collector performance can be readily assessed, including the comparison of pure thermal and pure photovoltaic collector performance with that of a combined collector. Several illustrative results have been presented in the paper.

It should, perhaps, be specifically noted that the extended model can be readily applied to pure photovoltaic collectors with cooling supplemented by forced or natural circulation of ambient air past the underside of the absorber. This requires setting $T_{f,i} = T_a$, and using an appropriate value of U_f for the particular thermal design employed.

One final note on the application of the model should be emphasized. For tube and sheet designs or other designs where the collector fluid is not in continuous contact with the back of the absorber plate, the plate would ordinarily be of metal or other high thermal conductivity material since portions of the absorber must then act as fins. In such designs, k , as it would affect eqn (8), e.g., is a mean value for the cell/plate composite absorber, weighted according to the cross-sectional areas (thicknesses) of cell and plate, since conduction along the absorber is being modeled in this case, with the temperature gradients across the absorber being neglected. In practice the weighted mean value would be essentially identical to k for the plate because of the negligible cell thickness relative to the plate. However, if a low thermal conductivity material such as glass is used as a back up plate for the cells, the design would allow for continuous contact of collector fluid with the plate, since the plate would not then be an effective fin. In this case only the cells would be treated as the absorber, since temperature gradients across the glass plate might be significant. If so, this would be accounted for in the model by including the effect of the thermal resistance of the glass plate in the overall thermal conductance U_f .

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NOMENCLATURE

A	dummy variable for integration over absorber area
A_c	total surface area of collector (absorber)
c_p	specific heat of collector fluid
D	tube outside diameter
F'	collector efficiency factor*
F_R	collector heat removal factor*
FWD	defined in text immediately following eqn (8)
F	defined in text following eqn (8)
G	collector fluid mass flow rate per unit collector area
H_T	solar radiation per unit area incident on collector
k	thermal conductivity of absorber (for cell/plate composite absorber will be weighted average value according to cross-sectional area of each material)
m	defined in text following eqn (8)
Q_e	overall electrical output of collector (q_e is local unit area value)
Q_L	overall thermal loss rate from collector (q_L is local unit area value)
Q_u	useful thermal energy collection rate*
S	solar radiation per unit area absorbed at absorber surface ($\tilde{S}$ is modified value defined by eqn (7))
T	local temperature of absorber
T_a	ambient temperature
T_f	local collector fluid temperature ($T_{f,i}$ is inlet value)
T_r	reference temperature for specification of solar cell efficiency
U_L	overall unit thermal conductance for collector heat losses ($\tilde{U}_L$ is modified value defined by eqn (6))
U_f	overall unit thermal conductance between absorber and collector fluid referred to absorber area
W	tube spacing for tube-and-sheet collector configuration
x	space coordinate transverse to collector fluid flow direction

Greek

α	effective absorptance of collector absorber
β_r	temperature coefficient of solar cell efficiency
δ	absorber thickness
ΔT	collector fluid inlet-to-ambient temperature difference ($T_{f,i} - T_a$)
η	local solar cell efficiency (η_r and η_a refer to values evaluated at reference and ambient temperature, respectively)
τ	transmittance of collector cover system

* These symbols refer to the values for a pure thermal collector. A tilde ($\sim$) over the corresponding symbol refers to the modified value for a combined collector.

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APPENDIX I

ANALYSIS OF SOLAR-AUGMENTED ROCK BED/HEAT PUMP SYSTEM

Analysis of Solar-Augmented Rock Bed/Heat Pump System

The system shown in Figure 1 has been analyzed for possible application in climates with well-balanced heating and cooling loads such as Washington, D.C. A more detailed schematic of the heat pump and rock bed portion of this system is shown in Figure 2. The question addressed in this analysis is whether such a system performs substantially better than the conventional, outside air source heat pump augmenting a solar heating system. The analysis is directed principally to the cooling season.

In order to understand the operation of this system the characteristics of a rock-bed store must be understood. These devices have been analyzed extensively, both in connection with solar heating systems (Refs. 1, 2), and in connection with analogous physical systems such as packed-bed chemical reactors (Ref. 3) and insulated ducts (Ref. 4). All of these systems obey a common pair of partial differential equations of the form

$$\frac{\partial \theta_a}{\partial x} = - \frac{h\alpha A_F}{\dot{m} C_{pa}} (\theta_a - \theta_p)$$

$$\frac{\partial \theta_p}{\partial t} = \frac{h\alpha}{\rho_p C_{pp}} (\theta_a - \theta_p)$$

in which

θ_a = fluid temperature (C)

θ_p = packing temperature (C)

h = heat transfer coefficient (kJ/hr-m²-C)

α = packing surface area per unit of
bed volume (m²/m³)

$\dot{m}$ = fluid mass flowrate (kg/hr)

C_{pa} = fluid heat capacity (kJ/kg-C)

C_{pp} = packing heat capacity (kJ/kg-C)

ρ_{pp} = packing density (kg/m³)
(mass per unit of bed volume)

A_F = frontal area of bed (m²)

Figure 2. Rock Bed in Parallel with Heat Pump. Air Flow Direction is for Cooling Mode.

Solution of these equations for some set of initial and boundary conditions, such as a specified inlet fluid temperature vs. time, yields both the fluid temperature and the packing temperature as functions of time and position in the bed. Such solutions are not expressible in closed form, but have been presented (Ref. 3, 4) graphically for the very special case of uniform initial bed temperature and a step change in fluid inlet temperature at time zero. These solutions, shown in Figure 3, can be used to approximate the outlet temperature for an arbitrary inlet temperature excursion by means of Duhamel's integral, as will be shown below.

Wide variations exist in the notations used in analyses of such systems. For example, Balcomb (Ref. 2) defines the "relaxation length" λ and finds the ratio of actual bed length L to λ to be an important parameter of the bed. The ratio L/λ is exactly the same as the "NTU" (number of transfer units) defined by Kays and London (Ref. 4). Also, the abscissa in Figure 3 may be interpreted as t/τ where t is time and τ is a time constant for the bed, defined by

$$\tau = \left[\rho_p C_{pp} / (h\alpha) \right] \times \text{NTU} = \frac{m_p C_{pp}}{m C_{pa}} \text{ (hr)}$$

$$\text{NTU} = h\alpha L_F / (\dot{m} C_{pa})$$

$$L = \text{bed length (m)}$$

$$m_p = \text{bed mass (kg)}$$

The interpretation of Figure 3 is as follows. For a bed of a particular NTU and τ , a one degree increase in fluid inlet temperature introduced at time zero (and maintained) will result in an outlet fluid temperature increase vs. time as indicated by the ordinate.

The discrete form of Duhamel's integral gives the bed outlet temperature for any inlet profile by representing the inlet profile as a series of steps. That is, if the step response (Figure 3) is represented by $f(t)$ and an arbitrary input is represented by the time series

$$\theta_1(t_i) = \theta(t_{i-1}) + \Delta\theta(t_{i-1})$$

THE INSULATED DUCT -- HIGH N_{tu} RANGE

FLUID TEMPERATURE RESPONSE, θ_f^*

Figure 3. Fluid Temperature Solution for Packed Bed with a Step-Change in Inlet Temperature.

the outlet temperature is

$$(1) \quad \theta_2(t_1) = \theta_1(0) f(t_1) + \sum_{k=i, i-1, \dots} \Delta \theta(t_k) f(\tau t_{i-k})$$

Simply stated, this says that the instantaneous outlet temperature equals the weighted sum of earlier inlet step changes, where the step response (Fig. 3) gives the weighting factors. Note that the initial terms in this sum, representing effects of recent changes in inlet temperature contribute relatively little since the step response is small for elapsed times less than about one-half of a time constant. On the other hand, much earlier steps are reflected in their entirety at the outlet since $f(t)$ approaches unity as the elapsed time becomes large with respect to the time constant.

The potential of a system as shown in Figure 2 can be seen by considering the case when NTU is very large, so that $f(t)$ approaches a step function. In this case a change in the inlet temperature is not observed at all the downstream end (the evaporator) until τ hours after the change. Thus if the time constant τ is at least equal to the daily cooling period, the heat pump can perform throughout the day with the evaporator cooling air at the initial rock bed temperature. All during this period the condenser is rejecting heat to an air stream at the conditioned space temperature, instead of the outside air temperature, therefore operating at a higher COP. The rejected heat, including that removed from the space as well as the heat pump shaft work, is stored in the rock bed. It is removed by reversing the air flow (not the heat pump fluid) at night.

It is clear that such a system offers a performance advantage over a conventional arrangement, provided that night temperatures are low enough to flush the bed to a temperature equal to or lower than the desired space temperature. This is a possibility in Washington, but unlikely in Phoenix. Additional advantages in the form of load shifting to off-peak hours can also be achieved by operating the heat pump in the early morning hours with the air flow reversed, thus sub-cooling the bed and delaying or eliminating the afternoon start-up.

It is recognized, however, that performance will be degraded if either rock bed NTU or τ are too low. The effect of a low NTU, as seen from Figure 3

and equation (1), is to allow recent changes in inlet temperatures to contribute to the outlet temperature. Such changes in inlet temperature will of course occur when the heat pump turns on due to the condenser rejected heat. If the outlet air temperature rises, the heat pump will have to work harder due to higher evaporator inlet temperature, offsetting the COP gain mentioned previously. The success of the concept therefore hinges on the value of NTU achievable in a practical rock bed, and on detailed analysis. A value of τ less than the total required on-time for space cooling will also result in loss of performance advantage.

A simple model was devised to evaluate the concept further. The model assumed an initial rock bed temperature equal to the desired space set temperature, 25.6°C. A rock bed design was selected according to guidelines suggested in Reference 2. the parameters for which are shown in Table 1. The following equations were then solved sequentially (see Figure 2 for notation):

$$(1) \quad T_{a2} = T_{RBO} + \Delta T_o f(t) + \Delta T_1 f(t-1) + \dots + \Delta T_k f(t-k)$$

$$(2) \quad Q_E = 42000 (1 + 0.036 (T_{a2} - 25.6))$$

$$(3) \quad COP = 2.5 (1 + 0.025 (T_{a2} - 25.6))$$

$$(4) \quad W = Q_E / COP$$

$$(5) \quad T_{a3} = T_{a2} - Q_E / (\dot{m}_a C_{pa})$$

$$(6) \quad Q_c = Q_E + W$$

$$(7) \quad T_{a1} = 25.6 + Q_c / (\dot{m}_a C_{pa})$$

$$(8) \quad \Delta T_k = T_{a1} - (T_{a1})_{old}$$

Here, Equation (1) is as described earlier. Equations (2) and (3) represent heat pump performance with variable evaporator temperature and were derived from manufacturers' literature and theoretical relationships (Reference 5). The remaining equations derive from application of the first law to the evaporator and condenser.

Table 1

ROCK BED DESIGN PARAMETERS

Mass = 11793 kg

Stone Diameter = 7.62 cm

$$\alpha = 55 \text{ m}^2/\text{m}^3$$

$$C_{pp} = 0.84 \text{ kJ/kg-C}$$

$$\rho_p = 1842 \text{ kg/m}^3$$

$$V = 7962 \text{ m}^3$$

$$\dot{m}_a = 2143 \text{ kg/hr}$$

$$L = 1.83 \text{ m}$$

$$A_F = 3.49 \text{ m}^2$$

$$A_{Flow}/A_F = 0.931$$

$$v = 1.52 \text{ m/sec}$$

$$h = 81.73 \text{ kJ/hr-m}^2\text{-C}$$

$$NTU = 10.75$$

$$\tau = 3.42 \text{ hr}$$

Heat Pump: 42200 kJ/hr

The calculation is started at time zero, when T_{a2} is known to be T_{RBO} , permitting the equations to be evaluated once. This yields a new T_{a1} and the first ΔT_k , and the equations are again evaluated. Repeating this procedure with one hour time steps, using the step response for $NTU = 10$ from Figure 3, the performance in Figure 4 through 7 were developed. Note that in Figures 5-7 the lower axis represents "on-time" for the heat pump and fan. The rate of advance along this axis in real time is dependent upon the space cooling load. A preliminary estimate of load for the Eastern house in Washington for an average July day are shown in Figure 4. This load profile was used to relate actual time to on-time, providing the upper axis on Figures 5-7.

From Figures 5 and 6 it is seen that the system performs as anticipated during the 1.4 hours of on-time, corresponding to the real-time period from noon to about 4:30 p.m. After that time, however, the evaporator inlet temperature begins to rise. From Figure 6 it is seen that evaporator heat removal goes up, as it must to maintain low supply temperature while the entry temperatures increase. The effect propagates through the system, resulting in higher heat rejection at the condenser, and lower capacity, Figure 6. Here system capacity and instantaneous performance, COP, are defined in terms of the over-all cooling effect, i.e.,

$$\text{System Capacity} = \dot{m}_a C_{pa} (T_R - T_{a3})$$

$$\text{System instantaneous COP} = \text{system capacity} / \text{heat pump work}$$

This COP is plotted in Figure 7, along with several others. The system average COP is defined as the ratio of integrated capacity to integrated heat pump work. It tends to stay higher than instantaneous COP due to the earlier high instantaneous values. The heat pump COP, defined as the ratio of evaporator heat removal to shaft work, tends to go up since as the evaporator inlet temperature goes up the heat is being pumped through a smaller temperature difference.*

*It is observed in Figure 5 that evaporator temperature actually exceeds the condenser temperature as on-time reaches about 1.6 hours. The work required is still finite due to cycle inefficiencies.

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Figure 4. AVERAGE JULY COOLING LOAD, WASHINGTON, D.C.

Figure 5. SYSTEM AIR TEMPERATURES

Figure 6. SYSTEM HEAT FLOWS

Figure 7. COEFFICIENTS OF PERFORMANCE

The most interesting comparison from Figure 7 is with the COP curve for the same heat pump in a conventional air-source arrangement. To get this curve, the same outside air temperature profile employed in the load calculations was used. It is seen that the proposed system has a higher average COP than the conventional arrangement up until about 7:00 p.m. However, since the cooling load persists until about 9:00 p.m., the average performance is less than for the conventional arrangement.

The trends evident in Figures 5-7 indicate that the bed NTU is too small. The heat rejected by the condenser is partially leaking through the bed, instead of being retained. Although not confirmed by further analysis, it might be assumed that an increase in this parameter by a factor of 10 would make the system attractive. In order to achieve such a value, one might consider either smaller packing object size or a larger bed. Smaller sized packing would result in both more surface area and higher heat transfer coefficient. Pressure drop through the bed would be adversely affected. These alternatives have not been pursued.

Turning now to January heating performance, the systems compared are sketched in Figures 1 and 8 and the results of the calculations are tabulated in Table 2. Two system configurations were studied. System one uses a solar thermal collector and rock bed storage, and a heat pump which is completely separate from the solar thermal system as shown in Figure 8. The collector is a high-quality single-glazed collector, 25.6 m^2 area. Its parameters were calculated according to the methods given by Beckman and Duffie (Ref. 6), and are nearly identical to those of the best single-glazed water-type collectors tested at NASA-Lewis. The rock bed and heat pump are the same as for the cooling calculations. System two uses the same components as system one, but with the heat pump in parallel with the rock bed as in the "rock bed" cooling system, Figure 1. System three has the same configuration as system two but the heat pump capacity is reduced to the minimum value capable of meeting cooling requirements. The larger heat pump in system two meets the heating requirement without any use of supplementary resistance heating, but has the disadvantage that air exiting from the evaporator coil can reach a temperature as low as 0°C . This would be highly undesirable because of frost formation. The smaller heat pump does not require defrosting but does require resistance heating (tabulated as Q_R in Table 2).

Figure 8. Air-Type Solar-Thermal Heating/Cooling System with Rockbed Storage and Parallel Heat Pump Augmentation.

Table 2

SOLAR HEATING WITH HEAT PUMP AUGMENTATION

WASHINGTON - AVERAGE JANUARY DAY

(Q IN 1000 kJ, E in kWh)

Hour	T_{OSA}	Q_T	System 1 (Fig. 8)			System 2 (Fig. 1)			System 3 (Fig. 1)			
			Q_S	Q_{HP}	E	Q_S	Q_{HP}	E	Q_S	Q_{HP}	Q_R	E
0	-2.70	-15.2					15.2	1.73				
1	-3.30	-15.5		10.1	1.49		15.5	1.78				
2	-3.72	-15.9		15.9	2.32		15.9	1.82			6.2	1.72
3	-3.83	-15.9		15.9	2.32		15.9	1.82			15.9	4.42
4	-3.72	-15.9		15.9	2.32		15.9	1.82			15.9	4.42
5	-3.33	-14.0		14.0	2.06		14.0	1.61		7.6	6.4	2.67
6	-2.70	-12.2		12.2	1.79		12.2	1.40		12.2		1.40
7	-1.89	-11.6		11.6	1.69		11.6	1.32		11.6		1.32
8	-0.94	-10.9	6.1	4.9	0.71	9.6	1.4	0.15	9.6	1.4		0.15
9	0.06	-9.3	15.8			19.3			19.3			
10	1.06	-7.8	22.4			25.8			25.8			
11	2.00	-7.1	25.6			28.5			28.5			
12	2.83	-6.4	26.0			28.8			28.8			
13	3.44	-6.1	23.3			26.2			26.2			
14	3.83	-5.7	17.3			19.4			19.4			
15	3.94	-5.7	8.0			10.2			10.2			
16	3.83	-5.7					5.7	0.65				
17	3.44	-4.6					4.6	0.53				
18	2.83	-3.5					3.5	0.40				
19	2.00	-6.4					6.4	0.74				
20	1.06	-9.5					9.5	1.08				
21	0.06	-11.6					11.6	1.33				
22	-0.94	-13.8					13.8	1.59				
23	-1.89	-14.6					14.6	1.66				
		-244.9	144.5	95.0	14.66	167.9	187.4	21.43	167.9	32.7	44.4	16.09
Fan Power					3.60			1.75				3.84
Collector Efficiency			0.58			0.68			0.68			
Heat Pump COP					1.9			2.4		2.4		1.3

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Ambient temperature was assumed to vary sinusoidally between average January daily high and low values, since 24-hour data was not available. Q_S is the heat delivered by the solar collector and Q_{HP} the heat delivered by the heat pump. E is the electrical energy consumed by the heat pump, including fan power; the additional fan power used to circulate air when the heat pump is not operating is tabulated below the daily totals. Average collector efficiency and heat pump COP (including Q_R) is also given.

As expected, coupling the heat pump and the solar thermal system increased collector efficiency (because of lower average air inlet temperature) and heat pump COP (because of higher average air temperature to the evaporator coil). However, note that the columns for system two show that the highest average collector efficiency and the highest heat pump COP are associated with the highest total electrical energy consumption.

This results not from the change in system configuration but from the operating mode assumed. For systems one and three, it was assumed that heat was delivered from storage without the use of the heat pump until stored heat was depleted; then the heat pump was used. For system two, it was assumed that the heat pump was used to pump heat from storage whenever stored heat was being utilized. The operating mode assumed in system three is clearly superior.

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APPENDIX J

TRNSYS RESULTS FOR WASHINGTON D.C. RESIDENCE WITH AIR COLLECTORS,
ROCK-BED STORAGE AND PARALLEL AIRESEARCH HEAT PUMP

TRNSYS RESULTS FOR WASHINGTON D.C. RESIDENCE WITH AIR COLLECTORS,
ROCK-BED STORAGE AND PARALLEL AIRESEARCH HEAT PUMP

SUMMARY

A TRNSYS model of the Eastern Residence was developed, incorporating a space conditioning system consisting of a rock-bed storage, air-type solar heating system and an Airesearch variable-speed heat pump for cooling. The heat pump also augments winter heating by operating in parallel with the solar system. This model was run for three identical days of averaged weather data (1962) in each of twelve months in Washington D.C. Additionally, the run for August was repeated using the Supreme-Aire heat pump for comparison. The results obtained are summarized herein.

DISCUSSION

System Description

A block diagram of the system is shown in Figure 1, where it is seen that the heat pump is in parallel with the air-type solar heating system. The heat pump is backed-up by resistance heating. The key parameters of the system are listed in the figure. Detailed thermal characteristics of the building are discussed in Reference 1. No attempt was made to optimize the solar system design, other than generally following recommendations of Reference 2.

The air flow circuit shown in Figure 1 is diagrammatic and representative of the way in which the system was modeled. Many physical realizations are possible, including some with only one fan (cf. Reference 2). In particular, note that the figure shows the rock bin connection with two unidirectional flow paths at each end, which enables TRNSYS modeling. An actual system would probably accomplish the same flow control with single ducts and appropriate diverters.

System Control

Control of space temperature and collection performance can be discussed in terms of seven modes.

- Mode 0: All equipment off
- 1: Cooling with heat pump
 - 2: Collector heat to store
 - 3: Collector heat to space
 - 4: Storage heat to space
 - 5: Heat pump heating
 - 6: Resistance heating

Some of these modes can co-exist, such as heat pump and resistance heating.

The logic in Table 1 was employed to establish which mode or modes exist at any time. For example, either Mode 2 or 4 require the diverters to be set so as to direct flow through the rock bed, while Mode 3 requires diverters set for flow directly through the collector. Thus in order for Mode 2 or Mode 4 to exist, the diverter control signal defined by Equation (1) of Table 1 must be true, while Mode 3 requires this signal to be false.

It will be noted that the heating mode is established by various temperature checks. An effort is made to maintain one of the solar heating modes in preference to heat pump heating, and heat pumping in preference to resistance heating. This is accomplished by having a space temperature set point of 20°C on solar heating, 19°C for heat pumping and 18.5 for resistance heating. Additionally, heat pumping is locked out whenever rock bed temperature is greater than 25°C regardless of space temperature, in order to inhibit heat pumping when there is a good chance of solar heating holding the temperature within reasonable limits, given enough time. Any drop below 18.5°C will bring the resistance heater on, but the solar system also stays on, and when the rock bed temperature finally drops the heat pump picks up the load. The heat pump is also locked out whenever the outside temperature falls below the point where its COP is less than 1.0. This is -15°C for the Supreme-Aire heat pump, and well below -20 for the Airesearch unit.

The collector loop functions only when the collector outlet temperature exceeds either the rock bed average temperature, or the inside space temperature. The latter condition will not cause this fan to come on unless there is also a demand for space heating.

Heat Pump

Most of the analysis was done with the variable speed heat pump under development by Airesearch. The performance of this air-to-air unit was modeled by the five charts shown in Figures 2-6, which were derived from data supplied by Airesearch. The coefficient of performance reflects the total energy consumed including inside and outside fans. Sensible-to-total ratio data was not available for the Airesearch unit, so data from a conventional unit of similar size (Singer Model CV 400) was used.

A currently-available, high performance heat pump manufactured by Supreme-Aire was also examined for comparison. Figures 7 and 8 show its performance.

The TRNSYS Model

The basic TRNSYS model block diagram is shown in Figure 9. The solar portion employs standard TRNSYS blocks, such as collector and rock-bed models, provided with version 7.3 by the University of Wisconsin. The residence itself is modeled by a space conditioning load model which was developed by Spectrolab. The heat pump model was also developed by Spectrolab.

The connection between the solar system and the space conditioning system is by means of a heat exchanger model which receives hot air from either the rock bed or the collector. This fictitious heat exchanger has an effectiveness of 1.0 and has the space inside air temperature on the side opposite the solar air stream, thus simulating a circulation of the solar air through the space. One output of the heat exchanger is the net heat transfer, which constitutes the solar heat delivered to the space. The heat pump and resistance heat are added to the solar heat to generate the total sensible space heating. The space load model adds the sensible heat from the conditioning equipment to that due to wall transmission (negative in winter), solar through windows and internal loads. The net heating is used to calculate the temperature derivatives of four dynamic nodes in the model, and integration produces the inside air temperature as a model output. Inside wet bulb temperature is also derived. As

the diagram shows, both of these outputs feed back to the heat pump since they affect its performance.

Inputs to the basic model of Figure 9 include weather parameters and control variables. The weather parameters include horizontal insolation H , direct normal insolation I_{DN} , outside air temperature T_a , and outside air absolute humidity W_{OSA} . The first two of these were simulated by daily profiles for each month determined by two-year averages during 1962 and 1963. Since night-time temperatures were not available from the data source employed, sinusoidal profiles were generated based on a two-part criterion: duplication of long term average degree-days, and average daily swing. National Weather Service summary data was used for this purpose. The absolute humidity was found to be relatively constant throughout the day, so a single value equal to the monthly average was employed.

Control parameters, such as the diverter signal δ_D , were generated by a control sub-model using Spectrolab-developed subroutines to implement the logic of Table 1. This control submodel is not shown in the diagram since it would more likely detract from the overall clarity than helping. The input and output model blocks have been omitted for the same reason.

The space internal load was simulated as a constant occupancy load of 1000 kJ/hr and, a profile of appliance and lighting power totaling 27400 kJ/day. Most of the appliance load was between 6 to 10 AM and 6 to 10 PM.

RESULTS

The model described above was run for three identical days in each of twelve months. The TRNSYS program calculates time-wise variations in all system parameters, some of which are shown in typical plots in Figures 10-12.

Figure 10 shows the load profile for the month of January, along with the division of this load between the solar heating system and the heat pump. It is evident that the solar system meets the entire heating load during most of the day, so that the heat pump only comes on in the morning.

Figure 11 shows the hour-by-hour solar system performance and the modes by which the solar-supplied heat enters the space. Part (a) of the figure shows the total solar space heating, while part (b) shows that coming from the rock bed, representing Mode 4 heating. By comparing (a) and (b) it is seen that the largest part of the solar heating is in Mode 4. Part (c) of Figure 11 shows the heat collection profile. If parts (a) and (c) are compared it will be noted that collection exceeds space heating demand from shortly before 10 a.m. until about 5 p.m. During this interval the air duct diverters are periodically switching between Modes 2 and 3. The shaded portion of part (c) represents direct space heating, and the remainder goes to the rock bed.

Several system temperatures are plotted in Figure 12. Part (a) shows the derived outside air profile, which is based on 567 Degree C-days (1020 Degree F days) and a swing of 7.8C (14°F). The maintained space temperature profile is shown in Part (d), where it will be noted that 20-21C is maintained during solar heating from about 10 a.m. to midnight. During heat pump heating, space temperature falls below 20 C since the heat pump thermostat is set at 19 C. Also, the average temperature tends to drop during the early morning hours as the rock bed becomes depleted.

Figure 12 (b) shows the average rock bed temperature. The bed is essentially depleted at about 6 a.m., and begins to recharge at about 10. It reaches a maximum of 38 C in late afternoon.

The temperature of solar-heated air delivered to the space is shown in Figure 12 (c). During Mode 4 operation this corresponds to the temperature at the top of the rock bed, and in Mode 3 it is the collector outlet temperature. It will be noted that the delivery temperature ranges from about 21 C to 42.5 C. This results a solar heating system capacity variation from 2100 to 48100 kJ/hr for 20 C space temperature and 1782 m³/hr air flow. The lower limit represents an arbitrary cut-off point for Mode 4 operation.

It is evident from the above that the collector size (50 m²) and the rock bed size (57320 kg) are approximately correct for the analyzed residence and the selected weather. The collector could be slightly larger, reducing the heat-pump on-time to zero, at least on the average. However, periods of poor weather will still result in some heat pump power consumption. Considering that January is the worst month, the larger collector would be under-used for most of the heating season and is therefore not justified. The rock bed size is justified by noting that the bottom temperature, Figure 12 (b), which is the collector inlet temperature, remains below 30 C throughout most of the collection period. This results in a high collector efficiency (e.g., 41% at 2 p.m.) which would be sacrificed with a smaller bed. On the other hand, a larger bed would not raise the average collector efficiency, since it is already receiving inlet air below 25 C for over 50% of the collection period.

The electrical power required to operate the solar system fans and the heat pump during January and July are presented in Figure 13. Fan power has been calculated based on 70% motor efficiency, 60% fan efficiency and estimated pressure loss in system components. Based on the work in Reference 2, rock bed and collector pressure drop were taken as 0.02 and 0.075 inches of water respectively. The duct and supply grill pressure losses were taken as 0.15, representing conventional design practice. The fan power varies from hour-to-hour due to on-time and the mode of system operation. Heat pump power requirements vary due to on-time, and outside air temperature (Figures 3 and 6).

It will be observed in Figure 13 (b) that the fan comes on during the cooling season. This is due to the control logic, which does not lock out solar system operation during the summer, as perhaps it should. As simulated, the rock bed loses some heat through its containing walls during the night, and this is made up during the hours of best insolation. The average bed temperature during this season tends to be 90 C. Clearly, it should be turned off, unless there is some mechanism for using the heat during the summer, for example, domestic water heating.

The Airesearch heat pump offers performance improvement by control of compressor speed and other advanced features. However, this unit is not presently on the market. In order to see the effect of this unit on the results of this study, the month of August was also analyzed using an available unit, the Supreme-Aire HP2.5. The results are compared in Figure 14. It is seen that the conventional unit requires almost twice the power of the advanced heat pump. This of course can be seen simply by comparing the cooling COP of the units shown in Figures 5 and 8.

Results for the entire year are presented in Tables 2 and 3. Table 2 shows the predicted thermal load for each hour on an average day in each month. These values were determined by the TRNSYS simulation, and are the integrated heats added (+) or removed (-) from the space by the conditioning equipment during each hour. It will be noted that heating and cooling were not allowed in the same month except in May. Also, the heat pump was turned on at 10 a.m. and off at 8 p.m., since natural ventilation should provide adequate space temperature control during other times of the day. This was verified by the model, since the predicted space temperature remained below 28.5°C after shutting off the heat pump at 8 p.m. in all summer months, even though window opening was not simulated. This is shown in Figure 15 where instantaneous space temperatures for July are shown. This profile is observed to vary somewhat erratically during the cooling period due to the on-off control of the heat pump.

It is of interest to compare the daily total load results predicted by the TRNSYS model with values predicted by the simple degree-day method. With this method the daily load is estimated by

$$Q_{\text{DAY}} = \frac{^{\circ}\text{C-day}}{\text{month}} \times \frac{\text{month}}{31 \text{ days}} \times \frac{24 \text{ hr.}}{\text{day}} \times \bar{U}A \frac{\text{kJ}}{\text{hr-}^{\circ}\text{C}}$$

where $\bar{U}A$ is the over-all inside-to-outside conductance, including infiltration. Values so calculated are shown as the last row in Table 2 and should be compared with the TRNSYS predicted daily total immediately above. The degree-day figures used were the same as those used in calculating daily temperature profiles. It is seen that fairly close agreement is obtained only during the cooling season. Large differences occur during heating season, most likely due to the fact that the residence examined here is much better insulated than those upon which the 65°F-base degree-day was confirmed. Agreement during intermediate seasons is also poor, but likely due to mixed heating and cooling days in these months. This factor is imprecisely treated by both the TRNSYS model which employed average weather, and the degree day method.

The space thermal load summarized in Table 2 must be met by operation of the space conditioning equipment, consisting of either the solar system fans, or the heat pump and resistance heating. The TRNSYS model calculated the instantaneous electrical power to operate this equipment and integrated the power over each one-hour period, producing the results shown in Table 3. Observe that these values represent energy used during the hour, not instantaneous power demand. For example, the table shows 0.6791 kWh during the hour ending at 1800 in July. Referring to Figure 6 and noting an outside air temperature of 29°C at this time, it is seen that the heat pump draws about 1.7 kW when it is on. The unit is on for $0.6791/1.7 = 0.4$ hours out of this hour. Small kWh values in the table represent energy consumed by the solar system fans, usually less than 80 Wh per hour.

By careful inspection of Table 3 it will be observed that the heat pump is off most of the time during the heating season. For example, only during the hours 7, 8, and 9 of January is the energy usage above that of the fans. This shows that the solar system is carrying all of the load on average days in all heating months except January. It is also noted that electrical power usage by the solar system fans is nearly negligible.

The time-wise correspondence between electrical energy demand for space conditioning and availability from a small-storage photovoltaic system is also indicated in Table 3. Horizontal lines show the times during which horizontal insolation exceeds 750 kJ/hr-m^2 , providing an arbitrary definition of hours of good photovoltaic availability. Table 4 shows the percent of daily energy demand occurring during this interval of direct availability of photovoltaic power. It will be observed that nearly 70% of heat pump energy requirements could be supplied with only enough storage to level the hourly demand, i.e., less than one kWh storage. The match is also good during the intermediate seasons, but fairly poor in the coldest winter months. Assuming a horizontal array and an average insolation of 0.5 kW/m^2 , an area of about 16 m^2 would

be required, along with a 1 kWh battery, and the system would provide over 64% of the annual space-conditioning power needs. The addition of enough storage to carry the heat pump into the evening hours in the summer, i.e., about 2-3 kWh total storage, would provide nearly 100% solar space conditioning. Periods of extreme weather would of course result in demand in excess of solar capacity, especially during the heating season. The model must be run with actual weather data in order to evaluate this effect.

CONCLUSIONS

The TRNSYS program has been used to model and analyze an energy-efficient residence incorporating solar heating and an advanced heat pump for back-up heating and cooling. The solar system is based on currently available air/rock-bed technology and employs 50 m² of double glazed air-type collector and a 57320 kg rock bed. The heat pump is in parallel. The model was run for 3 identical days of average 1962 weather in Washington, D.C., in each of 12 months. Results indicate that the solar heating system provides nearly all of space heating, its capacity being exceeded only in the morning hours of average January days. Day-to-day weather variations were not considered. The collector and rock bed sizes appear to be well chosen from a performance standpoint, but may be over-sized relative to a cost optimum. Fan power results in less than 0.5 kWh per day.

The variable-speed Airesearch heat pump results in very modest power requirements during summer cooling, about 5 kWh/day. Cursory calculations suggest that a 16 m² photovoltaic collector and a 3 kWh storage battery will provide nearly 100% of the electrical power required by this system.

RECOMMENDATIONS

The model developed herein should be expanded to include the photovoltaic components and used to evaluate year-round performance of the combined system. Actual weather data should be employed to investigate effects of day-to-day variations.

The rock-bed model employed in this study assumes a very high air/rock interface ($NTU = \infty$), which results in a greater "stratification" effect than will be achieved in practice. According to the University of Wisconsin, this is immaterial on a long-term average performance basis. If this proves not to be so, the collector area would have to be increased to achieve the same solar-thermal fraction. This should be investigated.

REFERENCES

1. Sowell, E. F. "Estimation of Space Conditioning Loads for Residential Photovoltaic System Studies." Spectrolab, Inc., March 1976.
2. Balcomb, J. D., et al, "Design Considerations of Air-Cooled Collector/Rock-Bin Storage Solar Heating Systems." Paper presented at ISES Conference, UCLA, July 1975.

Table 1

ROCK BED SOLAR HEATING
HEAT PUMP AUGMENTATION
- CONTROLS -

A. DEFINITION OF LOGICAL SIGNALS

l_1	$= T_{CO} > T_{RBA}$	
l_2	$= T_{ISA} < T_{SET1}$	$(T_{SET1} = 20C)$
l_3	$= T_{RBA} > T_{ISA}$	
l_4	$= T_{CO} > T_{ISA}$	
l_5	$= T_{ISA} < T_{SET2}$	$(T_{SET2} = 19C)$
l_6	$= T_{RBT} < T_{SET3}$	$(T_{SET3} = 25C)$
l_7	$= T_{RBT} > T_{CO}$	
l_8	$= 10 < TIME < 20$	
l_9	$= T_{ISA} > T_{SET4}$	$(T_{SET4} = 26C)$
l_{10}	$= T_{CO} < T_{SET1}$	
l_{11}	$= T_{ISA} < T_{SET5}$	$(T_{SET5} = 18.5C)$
l_{12}	$= T_{OSA} > T_{SET6}$	$(T_{SET6} = -15C)$

Table 1 (cont'd)

B. CONTROL SIGNAL LOGICAL EXPRESSIONS

Diverter:

$$(1) \quad Y_D = \bar{l}_1 l_2 + \bar{l}_2 l_1$$

$Y_D = \text{True} \Rightarrow \text{Rock Bed in the Loops}$

$= \text{False} \Rightarrow \text{Rock Bed out of the Loops}$

Rock Bed Fan:

$$(2) \quad Y_{P2} = \bar{l}_1 l_2 l_3$$

$Y_{P2} = \text{True} \Rightarrow \text{Heating from Rock Bed}$

Collector Loop Fan:

$$(3) \quad Y_{P1} = l_2 l_4 + l_1$$

$Y_{P2} = \text{True} \Rightarrow \text{Either Storing Solar Heat or Heating House Directly}$

Heat Pump Controller:

$$(4) \quad Y_{HPH} = l_5 l_6 l_{12}$$

$Y_{HPH} = \text{True} \Rightarrow \text{Heat Pump Heating}$

$$(5) \quad Y_{HPH} = l_8 l_9$$

$Y_{HPH} = \text{True} \Rightarrow \text{Heat Pump Cooling}$

Table 1 (Concluded)

Collector Loop Fan Speed Selector:

$$(6) \quad Y' = Y_D \ell_7 + \bar{Y}_D \ell_{10}$$

$Y' = \text{True} \Rightarrow \text{Fan on } \frac{1}{2} \text{ speed if it is on}$

$= \text{False} \Rightarrow \text{Fan on Full Speed it is is on}$

Resistance Heating

$$(7) \quad Y_R = \ell_{11}$$

$Y_R = \text{True} \Rightarrow \text{Resistance Heating on}$

Table 2: Space Conditioning Thermal Load
Eastern Residence in Washington
(10³ kJ)

HR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	
0	12.27	12.11	12.90	0	0	0	0	0	0	0	8.54	12.58
1	14.45	14.02	9.64	0	0	0	0	0	0	0	8.45	12.14
2	14.17	14.36	9.61	5.90	0	0	0	0	0	0	9.75	12.96
3	15.07	14.40	12.77	5.88	0	0	0	0	0	0	10.96	15.35
4	14.40	16.11	12.70	5.87	0	0	0	0	0	5.44	10.75	14.25
5	15.27	14.30	12.65	5.85	6.29	0	0	0	0	5.41	11.82	14.84
6	14.29	15.38	12.59	11.66	6.26	0	0	0	0	5.40	10.21	14.74
7	12.17	12.73	12.52	5.80	0	0	0	0	0	5.38	9.91	12.62
8	11.50	11.69	12.42	2.89	0	0	0	0	0	5.34	7.19	11.64
9	11.59	9.93	4.35	2.89	0	0	0	0	0	0	6.98	10.62
10	10.16	10.06	2.83	0	0	-0.66	-0.72	-0.67	0	0	3.01	8.17
11	10.28	9.89	3.10	0	0	-4.66	-11.78	-7.41	0	0	3.05	8.85
12	8.55	7.60	0	0	0	-5.43	-8.32	-6.77	0	0	1.56	5.99
13	4.38	5.85	0	0	0	-6.82	-8.85	-9.05	-3.44	0	0	2.46
14	4.82	2.30	0	0	0	-7.64	-10.73	-9.48	-6.32	0	0	2.28
15	1.88	4.21	0	0	0	-8.51	-10.21	-10.51	-7.97	0	0	0
16	1.63	1.40	0	0	-2.76	-9.35	-11.09	-10.63	-8.15	0	0	0
17	4.75	1.79	0	0	-4.20	-9.46	-11.04	-12.08	-7.51	0	0	0
18	3.51	4.26	0	0	-3.58	-8.09	-10.78	-10.37	-6.07	0	0	2.89
19	5.79	4.22	0	0	-3.62	-10.41	-11.23	-10.42	-7.65	0	0	2.87
20	5.70	5.57	0	0	-4.35	-8.26	-10.43	-9.00	-4.60	0	0	5.68
21	7.83	8.24	0	0	0	-0.75	0	0	0	0	0	5.61
22	8.73	8.09	0	0	0	0	0	0	0	0	0	5.29
23	12.65	10.55	7.58	0	0	0	0	0	0	0	6.37	10.85
Day	226.7	219.8	127.9	46.73	-5.95	-80.1	-105.1	-96.4	-51.7	26.97	106.5	198.3
Day*	(319.7)	(273.9)	(225.3)	(115.6)	(-17.7)	(-60.2)	(-99.0)	(-82.8)	(-58.4)	(91.2)	(190.0)	(301.2)

*By Degree-Day Method

**Table 3: Electrical Power Requirements
Space Conditioning
Washington Rockbed System (Airesearch Heat Pump)**

HR	kWh												YR
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC	
0	0.0270	0.0203	0.0090	0	0	0	0	0	0	0	0.0135	0.0225	
1	0.0338	0.0248	0.0068	0	0	0	0	0	0	0	0.0135	0.0225	
2	0.0360	0.0270	0.0068	0.0045	0	0	0	0	0	0	0.0158	0.0270	
3	0.0428	0.0293	0.0090	0.0045	0	0	0	0	0	0	0.0180	0.0315	
4	0.0473	0.0360	0.0090	0.0045	0	0	0	0	0	0.0045	0.0180	0.0315	
5	0.0630	0.0360	0.0090	0.0045	0	0	0	0	0	0.0045	0.0203	0.0360	
6	0.0855	0.0450	0.0090	0.0090	0	0	0	0	0	0.0045	0.0180	0.0405	
7	0.2661	0.0450	0.0090	0.0045	0.0063	0	0	0	0	0.0045	0.0180	0.0405	
8	0.6006	0.0518	0.0108	0.0031	0.0070	0	0	0	0	0.0045	0.0135	0.0450	
9	0.7540	0.0743	0.0186	0.0084	0.0543	0.0140	0.0088	0.0123	0.0053	0	0.0153	0.0544	
10	0.0993	0.0948	0.0329	0.0420	0.0700	0.1077	0.1053	0.1076	0.0595	0.0298	0.0408	0.0499	
11	0.0835	0.0813	0.0680	0.0700	0.0700	0.3506	0.7989	0.5286	0.0700	0.0700	0.0655	0.0813	
12	0.0775	0.0760	0.0700	0.0700	0.0700	0.4035	0.6149	0.5018	0.0700	0.0700	0.0715	0.0753	
13	0.0730	0.0738	0.0700	0.0700	0.0700	0.4989	0.6521	0.6506	0.2748	0.0700	0.0700	0.0715	
14	0.0730	0.0715	0.0700	0.0700	0.0691	0.5507	0.7789	0.6763	0.4444	0.0700	0.0700	0.0715	
15	0.0715	0.0721	0.0691	0.0691	0.0236	0.5993	0.7427	0.7369	0.5314	0.0691	0.0691	0.0700	
16	0.0680	0.0366	0.0350	0.0350	0.1749	0.6050	0.7577	0.6969	0.4772	0.0315	0.0350	0.0700	
17	0.0193	0.0453	0.0079	0.0061	0.2217	0.5672	0.7132	0.7466	0.4161	0.0009	0.0149	0.0123	
18	0.0068	0.0068	0	0	0.1800	0.4713	0.6791	0.6242	0.3267	0	0	0.0045	
19	0.0113	0.0068	0	0	0.1740	0.5834	0.6804	0.6035	0.3965	0	0	0.0045	
20	0.0113	0.0090	0	0	0.1987	0.4423	0.6033	0.5016	0.2295	0	0	0.0090	
21	0.0158	0.0135	0	0	0	0.0395	0	0	0	0	0	0.0090	
22	0.0180	0.0135	0	0	0	0	0	0	0	0	0.009	0.0135	
23	0.0270	0.0180	0.0045	0	0	0	0	0	0	0	0.009	0.0180	
Day	2.6130	1.0100	0.5242	0.4752	1.3896	5.2340	7.1357	6.3867	3.3017	0.4337	0.6050	0.9115	2.515

61-1

Table 4

Correspondence of Demand and
Photovoltaic Availability
(kWh/day)

<u>Month</u>	<u>Daily Demand</u>	<u>Daylight Demand</u>	<u>%</u>
Jan	2.613	0.4778	18
Feb	1.010	0.4695	46
Mar	0.5242	0.4336	83
Apr	0.4752	0.4345	91
May	1.3896	0.8306	60
Jun	5.2340	3.6969	71
Jul	7.1357	5.1725	72
Aug	6.3867	4.6526	73
Sept	3.3017	1.9326	58
Oct	0.4337	0.4104	95
Nov	0.6050	0.3869	64
Dec	0.9115	0.4195	46
Year	2.50	1.61	64

DESCRIPTION:

Collector Area	= 50 m ² ($F' = 0.88$, $\alpha = 0.9$, $\tau = 0.77$, $U_L = 15.27 \text{ kJ/hr m}^2\text{°C}$)
Rock Bed Size	= 57320 kg
Air Flow Rate	= 1782 m ³ /hr
Heat Pump Capacity	= 50,640 kJ/hr (4 ton) Airesearch = 31,650 kJ/hr (2.5 ton) Supreme-Aire
Overall UA	= 735 kJ/hr C (including Infiltration)

Figure 1. WASHINGTON RESIDENCE WITH AIR-TYPE SOLAR HEATING SYSTEM

FIG. 2. AIRESEARCH HEAT PUMP HEATING COP.

FIG. 3. AIRESEARCH HEAT PUMP HEATING POWER.

FIG. 4. AIRRESEARCH ESTIMATED SENSIBLE TO TOTAL COOLING RATIO. (BASED ON SINGER)

FIG. 5 AIRSEARCH HEAT PUMP COOLING COP VS. AMBIENT AIR TEMPERATURE.

FIG. 6 AIRSEARCH HEAT PUMP POWER INPUT FOR COOLING VS. AMBIENT TEMPERATURE.

FIG. 7. SUPREME-AIR HP2.5 HEAT PUMP
HEATING PERFORMANCE.

FIGURE 8. COOLING PERFORMANCE
OF SUPREME-AIR® HP2.5
HEAT PUMP.

FIG. 13. ELECTRICAL POWER REQUIREMENTS FOR SPACE CONDITIONING, FOR JANUARY AND JULY (WASHINGTON)

FIGURE 1A. COMPARISON OF COOLING SEASON POWER REQUIREMENTS FOR SUPREME-AIRE AND A RESEARCH PUMPS IN WASHINGTON.

FIG. 15. SPACE TEMPERATURE IN WASHINGTON RESIDENCE IN JULY.

APPENDIX K

TABULATION OF ELECTRICAL LOADS
FOR PHOENIX, RIVERSIDE, AND CLEVELAND
USING A SIMPLIFIED HOURLY METHOD DESCRIBED IN SECTION 4.2

Table 1

PHOENIX

AVERAGE ELECTRICAL SPACE CONDITIONING LOAD

SUPREME-AIRE HEAT PUMP

(Calculated by Averaged Data)

1962 (kWh)

	<u>Time</u>	<u>Jan.</u>	<u>Feb.</u>	<u>Mar.</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>Sep.</u>	<u>Oct.</u>	<u>Nov.</u>	<u>Dec.</u>	<u>Year</u>
K-2	0	0.759	0.590	0.552	0.0	0.0	0.283	0.974	1.108	0.450	0.0	0.337	0.720	
	2	0.964	0.749	0.821	0.034	0.0	0.0	0.657	0.785	0.132	0.092	0.521	0.868	
	4	1.020	0.868	0.895	0.175	0.0	0.0	0.407	0.531	0.0	0.198	0.644	0.992	
	6	0.925	0.709	0.889	0.126	0.0	0.0	0.194	0.478	0.0	0.118	0.500	0.827	
	8	0.707	0.098	0.0	0.0	0.0	0.685	1.325	1.307	0.631	0.0	0.047	0.638	
	10	0.0	0.0	0.0	0.522	0.963	1.814	2.216	2.284	1.469	0.198	0.0	0.0	
	12	0.0	0.0	0.0	1.672	1.808	2.637	3.078	3.201	2.129	1.309	0.0	0.0	
	14	0.0	0.0	0.0	2.100	2.188	3.120	3.508	3.580	2.500	1.596	0.0	0.0	
	16	0.0	0.0	0.0	2.000	2.103	3.094	3.544	3.580	2.433	1.508	0.0	0.0	
	18	0.0	0.0	0.0	1.638	1.758	2.784	3.184	3.254	2.145	1.186	0.0	0.0	
	20	0.109	0.0	0.0	1.030	1.160	2.053	2.523	2.523	1.632	0.155	0.0	0.0	
	22	0.597	0.312	0.1737	0	0.110	1.004	1.518	1.625	0.894	0.0	0.110	0.458	
	Total	<u>10.162</u>	<u>6.652</u>	<u>6.661</u>	<u>18.594</u>	<u>20.234</u>	<u>34.948</u>	<u>46.256</u>	<u>48.512</u>	<u>23.83</u>	<u>12.72</u>	<u>4.318</u>	<u>9.006</u>	<u>20.68</u>

Table 2

PHOENIX

AVERAGE ELECTRICAL SPACE CONDITIONING LOAD

EVAPORATIVE COOLER/GAS FURNACE

(Calculated by Averaged Data)

1962 (kWh)

<u>Time</u>	<u>Jan.</u>	<u>Feb.</u>	<u>Mar.</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Sep.</u>	<u>Oct.</u>	<u>Nov.</u>	<u>Dec.</u>	<u>Year</u>
0	0.007	0.006	0.006	0.0	0.0	0.0	0.154	0.154	0.0	0.0	0.004	0.007	0.029
2	0.009	0.007	0.008	0.0	0.0	0.0	0.154	0.154	0.0	0.001	0.005	0.008	0.029
4	0.009	0.008	0.008	0.002	0.0	0.0	0.0	0.154	0.0	0.002	0.006	0.009	0.017
6	0.008	0.007	0.008	0.001	0.0	0.0	0.0	0.0	0.0	0.001	0.005	0.007	0.003
8	0.006	0.001	0.0	0.0	0.0	0.0	0.154	0.154	0.154	0.0	0.001	0.006	0.040
10	0.0	0.0	0.0	0.0	0.154	0.154	0.154	0.262	0.154	0.0	0.0	0.0	0.074
12	0.0	0.0	0.0	0.154	0.154	0.154	0.705	0.705	0.262	0.154	0.0	0.0	0.193
14	0.0	0.0	0.0	0.154	0.154	0.154	0.705	0.705	0.705	0.154	0.0	0.0	0.229
16	0.0	0.0	0.0	0.154	0.154	0.154	0.705	0.705	0.705	0.154	0.0	0.0	0.229
18	0.0	0.0	0.0	0.154	0.154	0.154	0.705	0.705	0.262	0.154	0.0	0.0	0.193
20	0.001	0.0	0.0	0.154	0.154	0.154	0.705	0.705	0.154	0.0	0.0	0.0	0.171
22	0.006	0.003	0.002	0.0	0.0	0.154	0.154	0.154	0.154	0.0	0.001	0.005	0.053
Total	<u>0.092</u>	<u>0.064</u>	<u>0.064</u>	<u>1.546</u>	<u>1.848</u>	<u>2.156</u>	<u>8.590</u>	<u>9.114</u>	<u>5.100</u>	<u>1.24</u>	<u>0.044</u>	<u>0.084</u>	<u>2.522</u>

Table 3

RIVERSIDE

AVERAGE ELECTRICAL SPACE CONDITIONING LOAD

SUPREME-AIRE HEAT PUMP

1962 (kWh)

(Calculated with Averaged Data)

<u>Time</u>	<u>Jan.</u>	<u>Feb.</u>	<u>Mar.</u>	<u>Apr.</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Sep.</u>	<u>Oct.</u>	<u>Nov.</u>	<u>Dec.</u>	<u>Year</u>
0	0.926	0.879	0.961	0.493	0.0	0.0	0.0	0.0	0.0	0.518	0.926	1.200	
2	1.020	1.000	1.126	0.644	0.0	0.0	0.0	0.0	0.0	0.723	1.119	1.530	
4	1.133	1.126	1.271	0.755	0.0	0.0	0.0	0.0	0.0	0.862	1.271	1.611	
6	1.055	0.934	0.944	0.128	0.0	0.0	0.0	0.0	0.0	0.664	1.092	1.395	
8	0.129	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.201	
10	0.0	0.0	0.0	0.0	0.0	0.388	1.588	1.800	1.057	0.0	0.0	0.0	
12	0.0	0.0	0.0	0.936	0.380	1.633	2.388	2.778	1.965	0.607	0.0	0.0	
14	0.0	0.0	0.0	1.482	0.677	1.932	2.675	2.998	2.154	0.959	0.0	0.0	
16	0.0	0.0	0.0	0.911	0.054	1.579	2.080	2.320	1.609	0.295	0.0	0.0	
18	0.0	0.0	0.0	0.0	0.0	0.630	1.320	1.410	0.536	0.0	0.0	0.0	
20	0.231	0.392	0.234	0.0	0.0	0.0	0.0	0.193	0.0	0.0	0.163	0.387	
22	0.604	0.746	0.712	0.210	0.0	0.0	0.0	0.0	0.0	0.282	0.597	0.830	
Total	10.20	10.19	10.50	11.12	2.22	12.32	20.10	23.00	14.64	9.82	10.34	14.31	12.42

Table 4

RIVERSIDE

AVERAGE ELECTRICAL SPACE CONDITIONING LOAD

EVAPORATIVE COOLER/GAS FURNACE

(Calculated with Averaged Data)

1962 (kWh)

<u>Time</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Year</u>
0	0.008	0.008	0.009	0.005	0.0	0.0	0.0	0.0	0.0	0.005	0.008	0.010	
2	0.009	0.009	0.010	0.006	0.0	0.0	0.0	0.0	0.0	0.007	0.010	0.012	
4	0.010	0.010	0.011	0.007	0.0	0.0	0.0	0.0	0.0	0.008	0.011	0.013	
6	0.009	0.008	0.008	0.001	0.0	0.0	0.0	0.0	0.0	0.006	0.009	0.011	
8	0.001	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.002	
10	0.0	0.0	0.0	0.0	0.0	0.0	0.154	0.154	0.154	0.0	0.0	0.0	
12	0.0	0.0	0.0	0.154	0.0	0.154	0.154	0.154	0.154	0.0	0.0	0.0	
14	0.0	0.0	0.0	0.154	0.0	0.154	0.154	0.262	0.154	0.154	0.0	0.0	
16	0.0	0.0	0.0	0.154	0.0	0.154	0.154	0.154	0.154	0.0	0.0	0.0	
18	0.0	0.0	0.0	0.0	0.0	0.0	0.154	0.154	0.0	0.0	0.0	0.0	
20	0.002	0.004	0.002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.002	0.004	
22	0.006	0.007	0.007	0.062	0.0	0.0	0.0	0.0	0.0	0.003	0.006	0.008	
Total	0.09	0.09	0.09	0.97	0.0	0.92	1.54	1.76	1.23	0.36	0.09	0.12	0.61

K-5

Table 5

CLEVELAND

AVERAGE ELECTRICAL SPACE CONDITIONING LOAD

SUPREME-AIRE HEAT PUMP

(Calculated by Averaged Data)

1962

	<u>Time</u>	<u>Jan.</u>	<u>Feb.</u>	<u>Mar.</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Sep.</u>	<u>Oct.</u>	<u>Nov.</u>	<u>Dec.</u>	<u>Year</u>
K-9	0	2.650	2.306	1.760	0.903	0.128	0	0	0		0.509	1.191	2.469	0.987
	2	2.695	2.340	1.969	1.056	0.222	0	0	0		0.588	1.225	2.512	1.045
	4	2.695	2.470	2.009	1.088	0.294	0	0	0		0.626	1.225	2.512	1.071
	6	2.396	2.212	1.858	0.967	0.010	0	0	0		0.461	1.092	2.221	0.932
	8	2.390	1.986	1.117	0	0	0	0	0		0.083	0.970	2.081	0.714
	10	1.674	1.332	0.054	0	0	0	0.222	0.471		0.0	0.482	1.655	0.488
	12	0.745	0.476	0	0	0	0.434	0.688	1.011		0.0	0.019	0.889	0.357
	14	0.589	0.278	0	0	0	0.510	0.757	1.071		0.0	0.0	0.683	0.277
	16	1.208	0.910	0	0	0	0.364	0.559	1.067		0.0	0.259	1.237	0.467
	18	1.716	1.497	0.541	0	0	0.311	0.268	0.574		0.0	0.543	1.624	0.586
	20	1.984	1.810	1.094	0.036	0	0	0	0		0.049	0.707	1.835	0.621
	22	2.463	2.161	1.492	0.626	0	0	0	0		0.341	1.050	2.285	0.862
	Total	<u>46.41</u>	<u>39.55</u>	<u>23.79</u>	<u>9.35</u>	<u>1.31</u>	<u>3.24</u>	<u>4.99</u>	<u>8.39</u>	<u>0</u>	<u>5.25</u>	<u>17.52</u>	<u>44.01</u>	<u>16.81</u>

APPENDIX L

EVAPORATIVE AIR COOLERS:
COOLING EFFICIENCY AND ELECTRICAL CONSUMPTION

ENGINEERING MEMORANDUM NO. 680-321

By: Dr. Byard Wood (ASU)

Subject: Evaporative Air Coolers: Cooling Efficiency and Electrical Consumption

Date: March 17, 1976

With the aid of Dr. B.A. Kimball, who has been conducting research on evaporative coolers in relationship to greenhouses, we have prepared the discussion given below on evaporative air coolers. Even though it is obvious that little basic research has been done for residential evaporative coolers, it also seems evident from this report that significant gains in terms of evaporative cooler efficiencies are not forthcoming. It should be noted that Goettle Air Conditioning Company here in Phoenix has marketed a tandem unit which has an evaporative cooler in parallel with a refrigeration unit. It has proven to be quite popular here in the Southwest. In my discussions with people, it appears that more and more people are looking back to evaporative coolers as one viable alternative in cutting down their utility bills.

INTRODUCTION

Evaporative air coolers have been used for residential air cooling for about 40 years in the Southwest. Their initial costs are about one-half and their operating and maintenance are about one-fifth those of refrigeration air conditioners, but their inability to provide adequate comfort during the August "monsoon" season when wet bulb temperatures can rise to 78F or more has resulted in the use of refrigeration units by nearly everyone who can afford them. However, the recent energy crisis makes pertinent a reassessment of the role of evaporative coolers.

Refrigeration air conditioners typically have energy efficiency ratings, EER, from 6 to 9 Btu/hr/watt. This rating is based on 80F dry and 67F wet bulb room temperatures and a 75F wet bulb outdoor ambient temperature. The rating increases about 10 percent for an outside dry bulb temperature change from 105 to 85F. On this basis a 1500 ft² (12000 ft³) house with a 50,000 Btu/hr heat load would require an air flow of 12000 cfm to maintain an average temperature of 80F with an evaporative cooler capable of producing a 78F dry bulb from the outside ambient temperature of 105F. If the cooler's blower is 33 percent efficient and the pressure drop is .25 in H₂O, the energy efficiency rating of the evaporative cooler would be 47 Btu/hr/watt. If the outside dry bulb dropped to 85F, the cooler's EER would increase to 94 Btu/hr/watt.

This comparison makes the evaporative cooler appear 10 times as energy efficient as refrigeration. However, if the evaporative cooler were incapable of producing with with temperatures below 80F from the 75F wet bulb air outside (and most coolers could not), the cooler's EER would be meaningless. An infinite amount of fan wattage could not meet the specified temperatures. Thus the EER for an evaporative cooler can change drastically as the air coming from it departs from a reference temperature of 80F, a temperature chosen as reference because it is the upper limit of the human comfort range (ASHRAE Handbook of Fundamentals, p.137).

COOLING EFFICIENCY

The efficiency of evaporative coolers is generally expressed as the percentage ratio of the dry bulb temperature change of the air passing through the cooler to the temperature difference between the dry and wet bulbs of the air before it entered. An efficiency of 100% would be the maximum possible cooling, the dry bulb of the exit air equalling the wet bulb of the entering air. In the example above, an efficiency of 83% would be required to "break even" and obtain 80F air from the 105F dry, 75F wet bulb temperatures.

If the heat transfer coefficient, h (Btu/ft²/min/F) and the heat exchange area per unit volume of cooler pad, a (ft²/ft³), are known, their product, the cooler efficiency, E , can be predicted from Eq. 1 (Beall and Samuls, 1972).

$$E = 100 \{1 - \exp [-(h a L)/(Vdc)]\} \quad [1]$$

where L (ft) is the overall length or thickness of the heat exchanger, V ft/min is the air force velocity, d (lb/ft³) is the air density, and c is the humid air specific heat (Btu/lb/F). Equation [1] is based on the assumption that the water and air are uniformly enough distributed (i.e., little flow channeling) so that a log-mean air temperature profile develops.

Aspen Excelsior Pads

Benham and Wiersma (1974) conducted a series of measurements with wind tunnels to develop design criteria for aspen evaporative cooling pads. They used various thicknesses of pads oriented vertically, like commercial, and also horizontally. Pad density was 3 lb/ft³.

For the vertical pads the peak efficiency was 74 percent which was achieved with 3 in. or thicker pads with a pad face velocity of 250 fpm and static pressure drops of .25 in H₂O or more. Pads with a conventional thickness of 2 in. reached a peak efficiency of only 71 percent. This was at a velocity of 200 fpm and a pressure drop of .15 in H₂O.

Horizontal pads were found to have higher efficiencies. The 2 in. thickness attained an efficiency of 77 percent with a 225 fpm velocity at a .15 in. pressure drop (Table 1); The 3 in. thickness also had a 77 percent efficiency at a .15 in. pressure drop but at a velocity of 200 fpm. The 3 in. and thicker pads achieved a maximum efficiency of about 82 percent with a velocity of 250 fpm and a pressure drop of .25 for the 3 in. pads.

The increased efficiency of the horizontal aspen pads over vertical is probably due to an improved distribution of the air flow with less channeling. The water

was sprayed over the top so water distribution was probably also improved. Additionally, the air had contact with water droplets for a few inches above and below the pads, so the effective thickness of the horizontal pads was greater. Neither the vertical nor the horizontal pad data obey equation [1] very well, indicating flow channeling probably was occurring in these pads even though they were carefully constructed by Benham.

Welchert and Wiersma (1975) list additional advantages for using horizontal rather than vertical pads. The support structure is much simpler and pad cost is reduced because bulk excelsior can be used rather than straw based or machine packed pads. The pads don't sag with time so efficiency doesn't deteriorate nearly as rapidly with time. Easy access simplifies pad replacement and maintenance. Multilevel pad cabinet arrangements can be used which permit multistage cooling and winter ventilation control.

Corrugated paper

A material that has replaced aspen pads in some greenhouse evaporative cooling systems is marketed by Munters Corp., P.O. Box 6428, Ft. Myers, FL 33901. This material, called CELDEK, is a corrugated cellulose paper impregnated with insoluble anti-rot salts, rigidifying saturates, and wetting agents.

According to data furnished by the company, a 6 in. thickness of CELDEK (657517.5) has efficiencies of 88, 81 and 75 percent, and pressure drops of .01, .07, and .16 in H₂O for air velocities of 100, 300, and 500 fpm respectively. A 12 in. thickness has efficiencies of 98, 94 and 91 percent, and pressure drops of .02, .10, and .25 in H₂O for air velocities of 100, 300 and 500 fpm respectively. Thus for a maximum allowable pressure drop of .15, a 500 fpm velocity is possible with an efficiency of 75 percent with a 6 in. pad or a 400 fpm velocity with a 93 percent efficiency is possible with a 12 in. pad. For a .25 in. pressure drop the corresponding figures are 500 fpm and 91 percent for a 12 in. pad.

Munters attributes the increased efficiency to improved water distribution and a high surface area per cubic foot. Apparently they have achieved uniform flow with little channeling also because equation [1] predicts well how efficiency of the pads changes with thickness.

Table 1 compares CELDEK and aspen pad costs. The use of CELDEK would add about \$70-90 to the initial cost of a 4000 cfm cooler. If the CELDEK lasts 5 times longer than aspen as claimed by Munters, the material cost differential drops only about \$10 but this does not account for the labor and bother of changing the aspen annually. If this added maintenance as well as the probability that a smaller CELDEK unit could be used because of its higher efficiency (last line of Table 1), the costs of aspen and CELDEK are about equivalent.

Thus it would appear that in spite of higher initial cost of CELDEK, the longer life and higher efficiency make it logical to replace aspen in residential coolers at the present time. Indeed, if as claimed, a 93 percent efficiency can be achieved by CELDEK, the resultant temperatures within the human comfort range and high energy efficiency ratios make it logical to replace refrigeration units with CELDAK coolers in much of the Southwest.

On new residences it would be a relatively simple matter to size the ducting and air flow patterns to accommodate evaporative cooling. However, with houses originally fitted with refrigeration, the smaller duct size which can be used with refrigeration may introduce problems of excessive pressure loss and noise.

Two Stage cooling

Another possibility for achieving comfort air conditioning at costs lower than refrigeration is that of two stage evaporative cooling. As briefly described in the ASHRAE Handbook and Product Director (1973), two stage air cooling consists of first lowering the air temperatures with a dry heat exchanger and secondly with wet evaporative cooling. If the air were originally at 105F dry and 75F wet bulb and the dry heat exchanger lowered the dry bulb to 90, the wet bulb would also be lowered to 70F. Then a 77 percent efficiency cooler would achieve a final 75F exit dry bulb temperature rather than 82F for single stage. A 90 percent cooler could achieve 72 rather than 78F.

Attaining the extra cooling requires an evaporative water cooling tower, a water pump, and a dry heat exchanger. American Environmental Systems, Santa Rosa, CA manufacture a DiPeri dry cooler which combines the cooling tower, pump, and dry heat exchanger in one package. The air to be cooled is forced through tubes in one direction. Water is dripped over the outside of the tubes and evaporatively cools the tubes and the air stream inside them. A second air stream forced to flow at a cross direction to the first around the tubes causes the evaporation.

According to literature furnished by the company, their Model 6000 can produce 400 cfm of dry air at the 90F dry bulb maintained in the example above from 105F dry, 75F wet bulb air. The static pressure drop would be .43 in. H₂O on the dry side, and 2600 cfm at .25 in. H₂O would be required on the wet side. Taking an average temperature of 80F as the desired maximum, the heat load which could be removed by this system is 41,000 Btu/hr for a 77 percent cooler and 66,000 Btu/hr for a 90 percent cooler. If the air blowers have an efficiency of 33 percent, .82 HP would be required to move the air on the dry side and .32 HP on the wet side. For a pressure drop of .15 in., an additional .29 HP would be required to move the air the second stage evaporative cooler. Pump power for the two stages would be about .34 HP, to bring the total to about 1.77 HP or 1320 watts, ignoring pressure drops in ducts beyond the cooler. These figures give an energy efficiency ratio of 31 if the second stage is a 77 percent efficient cooler and 50 if the second stage is a 90 percent cooler.

Thus if the data furnished by the company are correct, it should be possible to achieve energy efficiencies with two stage evaporative cooling that are about 5 times greater than refrigeration. The temperatures achieved are well within the human comfort range for outdoor temperatures 105F dry and 75F wet bulb. The initial cost for a DiPeris cooler, from American Environmental, is \$1150. Adding a regular evaporative cooler plus wet side blower would give a total of about \$1650, not including installation, which is considerably more than about \$1000 for 50,000 Btu/hr refrigeration unit. At 50,000 Btu/hr and \$.04kW for electricity, it would take 3250 hours of operation for the savings in operating cost to equal the difference in initial expense. However it seems that \$1150 is a high price for a device with no precision mechanical parts and a non-metallic heat exchanger. Perhaps this price could drop with increased manufacturing volume and some competition.

ELECTRICAL CONSUMPTION OF EVAPORATIVE COOLERS

The primary consumer of electricity in an evaporative cooler is the fan or blower, the water pump power required being only about 15 percent of the fan power (Welchert and Wiersma, 1975). Figure 1 illustrates the ability of 1/2 HP motors to move air when attached to various sizes of fans and blowers from various manufacturers according to performance data furnished by the manufacturers. Comparing the 24 in. fans from ACME to those from Power Line or the 16 in. blower from Goettl to the 15 in. in Dayton, there appears to be perhaps a 10 to 25 percent difference between manufacturers. The simplicity of the propellers on the Power Line indicates they probably were designed for ease of manufacture, whereas the cambered twist of those from ACME for greater fan efficiency, and a 10 percent increase apparently was achieved. The Goettl and the Sears data are for actual evaporative coolers, so in comparison to the Dayton, it appears that the cooler manufacturers are using relatively efficient blowers.

The next thing that is apparent from Figure 1 is difference between propeller fans and squirrel cage blowers. At static pressure drops below about .15 in. H₂O, the propeller fans can move twice as much air depending on size, but as the static pressure increases past about .25 in., the blowers are better. If the structure to be cooled can be designed so that the total static pressure drop is no higher than .15 in. H₂O, clearly propeller fans are the logical choice. They are being used in structures such as greenhouses and livestock shelters that have an open design without partitions or air ducts so that pressure losses are low. In residences, however, the partitions necessitate air ducts with bends and corners so pressure losses are much higher; squirrel cage blowers are used, and electrical power consumption is correspondingly higher. If a residence were designed perhaps with a central propeller exhaust fan, evaporative pads on a special window in each room, and louvered doors, electrical consumption of evaporative cooling could be reduced on residences also.

The third and perhaps most striking thing about Figure 1 is the large difference in air moving ability between fans of different diameter with the same size motor. There is a direct trade-off between the higher initial cost of large fans with lower operating costs and the lower initial cost of small fans and higher operating cost.

CONCLUSIONS

1. The greatest efficiency that can be achieved with conventional aspen excelsior pads 2 in. thick and vertically oriented is about 71 percent. This would yield air at 84F from 105F dry, 75F wet bulb air.
2. Increasing thickness to 3 in. or more improves efficiency in vertical aspen pads to 74 percent and would obtain 83F air.
3. Changing orientation of aspen pads to horizontal increases efficiency to 77 percent for 2 in. pads and would obtain 82F air.
4. Again increasing thickness to 3 in. increases efficiency to 82 percent and would obtain 80F air.
5. Horizontal pads offer maintenance advantages over vertical.
6. Corrugated paper, CELDEK, apparently can achieve an efficiency of 93 percent and would obtain 77F air which is within the human comfort range.
7. When the longer life and greater efficiency are accounted, coolers equipped with CELDEK are about equivalent in cost to aspen coolers for a 5 year period. Their initial cost would be about 1/2 that of refrigeration units and their energy efficiency ratio would be about 75 Btu/hr/watt compared to about 7.5 for refrigeration.
8. Two stage cooling can achieve an over-all efficiency of 110 percent and yield 72F air which is well within the human comfort range.
9. An energy efficiency ratio of about 50 can be achieved with two stage cooling, but the initial cost is about 65 percent greater than refrigeration, at least if units from the one company are purchased.
10. For static pressures less than .15 in. in H₂O, electrical consumption of evaporative coolers can be reduced by 1/2 using propeller fans rather than squirrel cage blowers, but it is difficult to design residences so that this limit will not be exceeded.

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TABLE 1
COMPARISON OF HORIZONTAL ASPEN AND CELDEK EVAPORATIVE COOLER PADS FOR VARIOUS THICKNESSES
AND TWO PRESSURE DROPS

Static Pressure Drop (In H₂O)

Item	.15				.25	
	Aspen		CELDEK		Aspen	CELDEK
Thickness (in)	2	3	6	12	3	12
Efficiency (%)	77	77	75	93	81	91
Velocity (fpm)	225	200	500	400	250	500
Pad Area* (ft ²)	17.8	20.0	8.0	10.0	16.0	8.0
Pad Volume*(ft ³)	3.0	5.0	4.0	10.0	4.0	8.0
Initial pad cost*+(\$)	1.78	3.00	36.00	90.00	2.40	72.00
5 yr. pad cost*+@	8.90	15.00	36.00	90.00	12.00	72.00
Efficiency factor#	1	1	--	.38	.70	.41

*The Munters Corp., Ft. Myers, FL. For 4000 cfm unit

+Based on \$.20/lb and 3 lb/ft³ for aspen and \$9/ft³ for CELDEK

@Assuming 1 year life for aspen and 5 year for CELDEK and no labor cost for pad change

#Factor by which unit could be sized smaller from first column to take into account efficiency difference. Based on 100F dry and 70F wet bulb, 77F average exit temperature and 3F rise through house

Figure 1

APPENDIX M
HOOVER DAM OPERATION

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March 15, 1976

To: Fred Bartels
From: Don Evans
Subject: Hoover Dam Operation

Transmitted herewith is information on operation, electrical generation, and rated capacity of Hoover Dam and of Glen Canyon Dam.

HOOVER DAM

Contracts made when Hoover Dam was built now determine the operation of that facility. River operation below the dam and flood control receive highest priority in the operational hierarchy. Irrigation use and power production then follow in that order.

A group known as the Hoover Allotees, consisting mainly of the city of Los Angeles Department of Water and Power (LADWP), Southern California Edison (SCE), the Metropolitan Water District, the Cities of Pasadena and San Diego and to a lesser extent, some commitments to Nevada and Arizona (about 160 MW capacity each), now share in the use of the energy generated. Although the federal government owns the turbines, they are maintained and operated by LADWP and SCE. Both LADWP and SCE operate control rooms on site at Hoover, but their main dispatch offices are located in the Los Angeles area.

At the beginning of each water year (October 1 through September 30), the Colorado River Storage Project (CRSP) division of the Bureau of Reclamation, U.S. Department of Interior, gives the operators of turbines (LADWP and SCE) a month-by-month schedule of projected water releases for the upcoming year. These are based on projected water use requirements in the U.S. and Mexico, programmed levels of Lakes Mohave and Havasu and transit losses. Since the filling of Lake Powell upstream started in the early 1960's, these projections have been based on minimum requirements in order to maintain a stable elevation for the surface of Lake Mead.

As long as a minimum release of water is made, and as long as the total monthly release meets CRSP schedules, the operators of the generating facility are free to schedule the diurnal patterns of releases throughout each month. The minimum release is necessary to maintain river operation; it is governed only by a gentleman's agreement between the operators' and the CRSP. The monthly schedules established by CRSP are subject to change due to, for instance, changes in irrigation orders due to downstream rains.

In the water year 1974, the total release from Lake Mead through Hoover Dam was 8,846,500 acre-feet. This corresponded to an electrical energy generation of approximately 4×10^9 kWh. During that same year the average daily releases were quite constant during the months of October through January and again from March through August. The summer averages were nearly twice the winter averages. This corresponds to roughly 2.2×10^8 kWh/mo during winter months and 4.4×10^8 kWh/mo during summer months. Such outputs have been more or less typical since the filling of Lake Powell began.

The rated capacity of the installed turbines at Hoover is 1,344,800 kW based on a rated lake elevation of 1123 feet (the elevation during the water year 1974 remained near 1180 feet). Based on this rated capacity, the energy production noted earlier for 1974 corresponds to a plant capacity factor of about 34%.

GLEN CANYON DAM

Glen Canyon Dam was built primarily for storage and irrigation uses. It impounds Lake Powell to insure that the upper basin of the Colorado River (essentially all of the Colorado River drainage basin above Lee's Ferry, AZ) can deliver a controlled flow to the lower basin. Flood control and power generation, although secondary considerations for construction of the dam, now are important benefits.

The federal government owns and operates the entire facility. It differs from Hoover Dam in that the operation is not contracted out but the energy generated is sold to various utilities and municipalities. These users can, however, have an input as to when during the day the energy is generated. Total rated capacity for all units is 900MW. There are firm commitments on 80% of this capacity at 58.2% load factor to the so-called Northern District and on 20% of the capacity at 58.2% load factor to the so-called Southern District.

These Southern District commitments are to southern Arizona, Nevada and the Imperial Valley region of California. Some energy finds its way to the Los Angeles area as a replacement for the deficiency in Hoover Dam's output created by the construction of Glen Canyon Dam and the filling of Lake Mead. In the past, the Southern District has taken more than 20% but starting in 1976 this practice will end.

Legal restrictions determine yearly total water releases from Lake Powell. These require that 8.2×10^6 acre-feet per year plus enough water to equalize storage between Lakes Mead and Powell on September 1 of each year, be released through Glen Canyon Dam. The 8.2×10^6 acre-feet figure corresponds to a generation of about 3.7×10^9 kWh per year. As long as these requirements are met, monthly and diurnal schedules are governed only by the requirements that maximum flows of about 30,000 cfs not be exceeded and minimum flows of 1000 cfs (approximately 35MW) during the winter and 3000 cfs (approximately 105MW) during the summer be maintained or exceeded at all times.

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The power operation of the dam is tied to the utility grid in such a way that any or all of the eight generator units can be computer controlled to supply energy when users want it. It can also be operated in such a way that blocks of power can be sold. Presently, the peak loads during the summer and winter are roughly the same. Energy generation is slightly higher in the summer than the winter, however.

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