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SOLAR THERMAL ENHANCED OIL RECOVERY (STEOR). VOLUME 2 (SECTIONS 2–8)

Final Report for Period October 1, 1979—June 30, 1980

By
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David Allen
Patrick Joy
Henry Shaw
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Paul Mitchell

November 1980

Work Performed Under Contract No. AC03-79CS30307

Exxon Research and Engineering Company
Linden, New Jersey

and

Foster Wheeler Development Corporation
Livingston, New Jersey

and

Honeywell Incorporated
Minneapolis, Minnesota

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VOLUME II — FINAL REPORT
(SECTIONS 2-8)

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2. INTRODUCTION

This study was undertaken in response to Program Opportunity Notice 03-79-CS30051, Solar Thermal Steam Generation System For Use In Enhanced Oil Recovery Operations. Exxon Research and Engineering Co. (ER&E) as the prime contractor coordinated the activities of participating Exxon Affiliates; Exxon Co. USA (EUSA), Solar Thermal Systems Div. of Exxon Enterprises (STS), and Exxon Production Research Co. (EPRCO). Foster Wheeler Development Co. (FWDC) and Honeywell, Inc. (HW) participated as major subcontractors. The period of performance was from October 1, 1979 to June 30, 1980.

This section summarizes the program objectives, describes the proposed site for Solar Thermal Enhanced Oil Recovery (STEOR) demonstration and highlights the technical, economic and operational issues which are addressed in the body of the report. More emphasis is put on the site description because it is not discussed elsewhere in the body of the report.

2.1 Program Objectives, Scope And Issues

The purposes of this section is to state the objectives of the program, define its scope and list the issues which have been addressed in the body of the report.

2.1.1 PROGRAM OBJECTIVES

The broad program objectives were to:

(1) Determine the technical, economic, operational and environmental feasibility of solar thermal enhanced oil recovery using line focusing distributed collectors at Exxon's Edison Field.

(2) Estimate the quantity of solar heat which might be applied to domestic enhanced oil recovery.

As can be seen the first objective was specific to Exxon's Edison Field while the second objective considers the broader question of STEOR application country wide. It is important to recognize that conclusions drawn from the Edison site may or may not be applicable to other domestic sites and vice versa.

2.1.1.1 Definition Of STEOR Feasibility At Edison

As implied in the first objective, feasibility considers technical, economic, operational and environmental factors. However, these factors are not independent. As an example, a project having high economic return or a large positive environmental effect could be judged feasible in an overall sense even though there might be higher than usual technical risk. In the case of the Edison Field all of these factors have been considered by Exxon experts in project economics, resevoir engineering, solar technology, environmental and regulatory matters and therefore the conclusions reached are a consensus of their judgements.

2.1.1.2 Quantity Of Solar Heat Which Might Be Applied To Domestic Enhanced Oil Recovery

It is apparent that the second objective is not independent from certain aspects of the first objective. An example of this is the technical feasibility of the solar technology used which sets an upper limit on temperature and therefore limits the solar contribution at those sites requiring steam pressures corresponding to higher temperatures. As a result, conclusions drawn on the second objective pertain to the technology being considered.

2.1.2 PROGRAM SCOPE

The program was influenced by both DOE and Exxon constraints. The DOE contract limited the solar technology to line focusing distributed collectors which were to provide at least 33% of the project heat. In addition, most of the economic incentives are provided by regulations of the Economic Regulatory Agency of the DOE which limit the maximum investment to \$26.7 x 10^6 and the project completion of construction payments date to September 31, 1981. Exxon's requirements are that the project provide an acceptable return and that the technology evolves in performance and cost so that it can be used in other enhanced oil projects or other industrial process heat applications.

2.1.3 PROGRAM ISSUES

A large number of technical, economic and site specific issues were considered in meeting the above objectives. Most of these issues are common to all sites, however, some sites are dominated by one or two overriding factors. Table 2.1 classifies and lists the issues which were considered and indicates the methodology used for evaluating each issue.

Table 2.1

Issues Considered In STEOR Feasibility Study

Issue	Methodology
Technical	
o Solar Equipment Performance And Operability	- Surveyed Manufacturers, Visited Demonstration Sites
o Fraction Solar/Interface With Oil Field	- Defined Potential Problems And Proposed Program
o Interface With Conventional Boiler	- Discussed With Boiler Manufacturer And Developed Interface
o Improvements For Conventional Boilers	- Surveyed Boiler Manufacturers
o Alternative Fuels	- Considered Coal, Gas And Downhole Steaming For Edison
Economic	
o Solar Equipment Cost	- Obtained Quotes From Manufacturers And Projected Future Trends
o Economic Parameters (Inflation, Fuel Costs)	- Used Available Published Information
o Incentives	- Interpreted Existing Federal And State Regulations And Laws
o Financing	- Evaluated Available Techniques
Site Specific	
o Operating Temperature, Pressure And Flows	- Surveyed 21 California Oil Fields And Analyzed Edison In Detail
o Development Plan For Reservoir	- From Operators Statements
o Geological Factors (Topography, Hydrology, Soil, Earthquake)	- From Geological Survey Maps And Site Visits
o Climate (Insolation, Dust, Temperature, Precipitation)	- Used Published Information, Measured Insolation At Edison
o Environmental (Air And Water Quality)	- Analyzed For Edison And Projected For California
o Socio/Economic (Alternative Uses For Land)	- From Operators Statements And Site Visits

2.2 Site Description

This section discusses the site and operational factors which influence the use of solar heat at the Edison field.

2.2.1 PROPOSED SITE FOR STEOR DEMONSTRATION

The proposed site is located at Exxon's Edison field in Kern County, California. This field is an ideal location for a demonstration since its response to steam stimulation has been well established during the past 15 years and it has a nearly level terrain which should simplify the installation and operation of trough type collectors. In addition, it is in an area of high annual insolation. At this time, most of the potential site problems appear to be solvable using well established technology. Seismic activity and dust are the two most obvious problems of this type. This section emphasizes the major site related parameters and uncertainties. Appendix A contains more detailed site information.

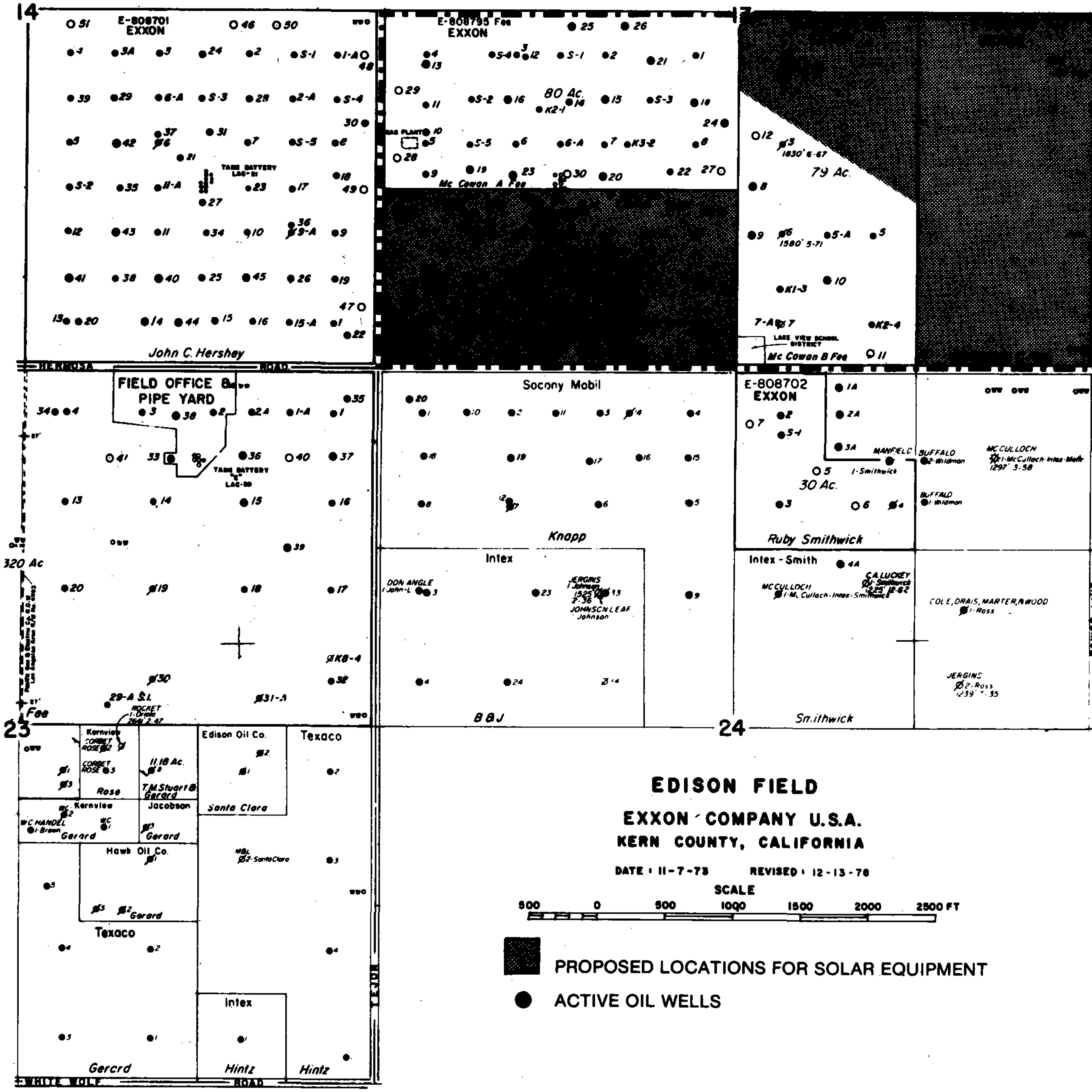
Two locations within the boundaries of the Edison field were considered for solar equipment. One is in an operating area of the field (lease 808794) and the other is to the east on Exxon owned leases believed to be beyond the active area of the field. Figure 2-1 shows these areas in relationship to the rest of the field. Solar equipment would be located with ample allowances for access to wells and spacing between collectors to minimize shadowing. Both areas were considered to allow a comparison of costs and operations.

2.2.2 MEASURED INSOLATION AT SITE

The system performance is directly related to the direct normal insolation at the site. Since there are no measured values of this parameter for Bakersfield, data from Fresno 177 km (110 miles to the N-NW) were used for performance estimates. Fresno and Bakersfield are both in the San Joquin Valley which is under intensive agricultural production and therefore similar insolation levels are expected.

A measuring station located 46 meters (50 yards) to the south of the field office has been in operation since January 1980. It is planned to continue measurements at least through 1980. A description of the station, data tables and analysis are contained in Appendix A.

The data are summarized in Table 2.2 which compares the measured direct normal (DN) and total horizontal (TH) insolation at Edison for the period January through June 1980 with that of the Fresno Typical Metrological Year (TMY) and with measured Fresno TH insolation for the same period. (Fresno DN insolation has been measured, but is not yet available). The table shows



POTENTIAL AREAS FOR LOCATING TEST SITE (SHADED)

FIGURE 2.1

115-646

Table 2.2

Edison Field Insolation Comparisons

Kwh/m^2-Day (BTU/ft^2-Day)

Month	1980 Edison Measured				1980 Fresno Measured		Fresno TMY Data			
	Mean Daily Total Horizontal		Mean Daily Direct Normal		Mean Daily Total Horizontal		Mean Daily Total Horizontal		Mean Daily Direct Normal	
January	2.00	(634)	2.01	(638)	2.20	(698)	2.11	(669)	2.33	(739)
February	3.72	(1180)	5.09	(1615)	2.85	(904)	3.26	(1034)	3.70	(1174)
March	4.57	(1450)	6.11	(1938)	5.50	(1745)	5.01	(1589)	5.66	(1795)
April	5.09	(1615)	4.85	(1538)	6.70	(2125)	6.66	(2113)	6.98	(2214)
May	5.98	(1897)	5.41	(1716)	7.27	(2306)	7.89	(2503)	8.07	(2560)
June	7.71	(2446)	8.9	(2823)	7.88	(2500)	8.57	(2719)	9.15	(2902)
Jan.-June Average	4.81	(1526)	5.41	(1716)	5.79	(1837)	5.60	(1776)	5.99	(1900)

a mean daily DN for Edison of 5.41 Kwh/m^2-day (1716 BTU/Ft^2-day) and a mean daily TH of 4.81 Kwh/m^2-day (1526 BTU/ft^2-day) which are, respectively, 10% and 14% lower than the Fresno TMY data. The 1980 Fresno TH data is 3% higher than the TMY tape but is within the spread ($\pm$8%) of any given year compared to the TMY.

Due to the short period of data gathering at Edison and the lack of long term insolation data for the Bakersfield Area, it is difficult to draw any definitive conclusions concerning the Edison measurements. From the data taken to date, however, it would appear that the Edison field may have somewhat lower insolation levels than Fresno on a historical basis.

Performance estimates are based on the DN radiation values from the Fresno TMY tape. Therefore, if the rest of the year continues with the same trend and this is indicative of the long term average, performance will have been overestimated by 15%. This will reduce the economic incentive for STEOR. However, the reduction is not expected to be large enough to affect the overall value of STEOR at Edison.

2.2.3 CURRENT OPERATIONS AT EDISON FIELD

Most of the current production of 0.0022 m^3/s (1200 BOPD) is from the Kern River formation at an average depth of 518 m (1700 feet) below the surface. Steam stimulation was initiated in 1965 using a 6.4 MW (22 MBTU/h) oil field boiler. Near term production will be maintained through the use of a second boiler, 7.3 MW (25 MBTU/h), now in operation. Current practice is to move a boiler adjacent to a well during steaming. Each steam job takes about one week to inject 1590 m^3 (10,000 BBL) of water as 80% quality steam. As a result of moving and maintenance, the boiler service factor is about 70%.

2.2.4 FUTURE OPERATIONS AT EDISON FIELD

An important parameter in the economics of using solar heat is the project life. Usually 15 to 20 years is considered a reasonable life for solar equipment. However, for STEOR the expected life of the oil field must also be considered. Reservoir analysis has shown that the life of the Edison field should be greater than the 15 years used in the economic analysis for justifying a solar investment.

2.2.5 OTHER SITE CONSIDERATIONS

Other site related problems at this time appear to be workable by conventional engineering design techniques and operation procedures.

- o The Edison Field is in a high seismic risk zone (UBC zone 4). However, equipment, foundations and other structures can be designed accordingly.
- o High levels of dust could be a problem at times by settling on reflecting surfaces. It has been assumed that reflecting surfaces will be washed when the reflectively reaches 90% of that of a clean surface.
- o The Edison Field requires higher steam pressure than do most of the other California heavy oil fields. Therefore, most other fields will not have to be so concerned with exceeding the temperature limits of trough collectors.

2.3 Project Organization

The project was executed by a team of experts from Exxon, Foster Wheeler and Honeywell, Inc. The areas of responsibility by organization is summarized in Table 2.3

Table 2.3

Team Members Major Responsibilities

Company	Responsibilities
o Exxon Research and Engineering Co.	- Project Management - Environmental Impact - Process Engineering
o Solar Thermal Systems Div. of Exxon Enterprises, Inc.	- Market Analysis - Economic Analysis - Solar Technology
o Exxon Co. USA	- Reservoir And Steam Requirements Analysis
o Exxon Production Research Co.	- Reservoir Simulation - Survey of California Oil Fields and Analysis
o Foster Wheeler Dev. Co.	- System Integration And Cost - Safety And Reliability Study
o Honeywell, Inc.	- System Performance Simulation - System Control

2.4 Final Report Organization

The final report has been presented in three volumes. The first volume provides an Executive Summary and the table of contents of the entire report. The second volume summarizes all of the work done under the contract Statement of Work. The third volume contains the additional work done in preparation of a second preliminary design for a preheat only solar energy system. The solar energy systems were designed primarily for Exxon's Edison California oil field. The Executive Summary (Volume I) draws from both Volumes II & III and is an overall assessment of Solar Thermal Enhanced Oil Recovery with line focusing collectors. The Executive Summary also contains Exxon's recommendations relative to STEOR in general.

Table 2.4 lists the sections of Volumes I & II which discuss each of the tasks in the contract Statement Of Work.

Table 2.4

Volumes I & II, Sections Containing Results From Contract Tasks

Task No.	Task Title	Sections	Notes
1	Systems Analysis	3	- For Solar Hybrid Systems
		4	- For Solar Hybrid System Trade Studies
		8	- For Natural Gas, Coal And Downhole Steaming
2	Preliminary Design	5	
	Site Solar Data	2	
3	Product Improvement	8	
4	Reservoir Analysis	2	- Edison Field Life
		8	- Proposed Program For Diurnal Steaming
5	Market Analysis	8	
6	Test Plan For Phase IV	7	
7	Schedule And Cost For Remaining Phases	6	- Contains Cost Estimates For Design And Construction
		7	- Contains Schedule For Design And Construction And The Schedule And Cost For System Tests.
8	Recommendations For Phases II, III, IV	1	
10	Utilizing ERA's Financial Incentives	8	

2.5 Cost Estimating Differences

Sections 3 through 8, the Appendices and Volume III include several capital cost and energy cost estimates. These appear in the tradeoff studies, in the market analysis and in the preliminary designs. The initial tradeoff studies and the flash separator/preheat plus storage preliminary design (Sections 3 through 6) use evolving Foster Wheeler cost estimates, economic parameters per Appendix B-2, and the unconventional, Foster Wheeler P.R.P. method of constant dollar, before-tax life cycle costs for energy. Sections 1, 8, and Volume III use the Exxon assumed economic parameters of Section 8, and a conventional current dollar after-tax, life cycle cost analysis (LCC method) such as: Dickinson and Brown "Economic Analysis of Solar Industrial Process Heat Systems" UCRL 52814 August, 1979.

Appendix I presents a detailed technical explanation of the differences between the P.R.P. method calculations used by Foster Wheeler and the standard LCC method used by Exxon. Table 6.6 provides a sample reconciliation of the Foster Wheeler cost estimate for a preheat only system with the Exxon cost estimate. Explanatory notes in Sections 3 and 4 are included to remind the reader that the Foster Wheeler P.R.P. method before tax energy costs are approximately 2.6 times the Exxon LCC method after tax energy costs shown elsewhere.

3. SELECTION OF SYSTEM

A major component of the program to investigate the feasibility of using solar thermal energy in enhanced oil recovery operations at Exxon's Edison, California, field, was the selection of the system to be used. A variety of conceptual designs had been proposed. As a basis it was assumed that 23,225 m^2 (250,000 ft^2) of solar collectors would be used to produce approximately 20,520 MWh/Yr (70 x 10^9 Btu/yr) of useful thermal energy and that the solar thermal system would supplement a single 7.32 MW (25 x 10^6 Btu/h) fired boiler. These constraints are important in that they necessitate steam generation with solar energy unless extensive modifications are made to the fired boiler and the boiler feedwater pump is replaced. Accordingly all the conceptual designs prepared allow for solar steam generation.

At the Edison field, a well-head steam pressure of 5,611 kPa absolute (800 lb/in^2a) is desirable for both steam stimulation and steam drive operations. This requirement will be seen to greatly influence the conceptual designs prepared. System selection was based primarily on estimates of cost and performance. However, technical readiness, environmental factors, safety, and reliability were also considered.

Four basic conceptual designs were evaluated in detail, alternatives to these designs were considered, and possible problems with the basic designs identified. The basic concepts were:

- Flash-separator system
- Unfired boiler system
- Hybrid unfired boiler/feedwater preheat system
- Flash separator/feedwater preheat with storage hybrid.

In addition, a concept employing natural circulation and the direct boiling of water in the collectors was evaluated in less detail for purposes of comparison. The descriptions and evaluations of all these concepts will now be presented and conclusions drawn.

The remainder of this section discusses each concept in detail, summarizes the results, and presents the conclusions. Since the solar collector subsystem is common to all concepts it is presented first.

NOTE

The annualized cost of energy figures in this section are based on before tax, equal annual 1979 dollar costs as calculated by Foster Wheeler using the P.R.P. life cycle cost calculation method and assumptions described in Appendices B.2 and I. In sections 1 and 8, Exxon has calculated after tax annualized energy cost estimates which are based on equal annual current dollar (decreasing annual constant dollar) energy costs. To a first order, the before tax P.R.P. method Foster Wheeler values can be multiplied by 0.39 to approximate comparable after tax Exxon values, given equivalent cash flows and incentives.

3.1 Collectors and Controls

3.1.1 THE COLLECTOR FIELD

The unfired boiler and flash-separator concepts were evaluated using identical collector fields. These fields were divided into four blocks, each further divided into four units. The units contain twenty-four 24-m (80-ft)-long collectors, each consisting of four 6-m (20-ft) collector modules, oriented in a north-south direction. The modules possess separate tracking and drive mechanisms. This field layout is shown in Figure 3.1. The flash separator/feedwater preheat hybrid with storage system was evaluated with a different field arrangement but with the same collector area and spacing (Figure 3.2).

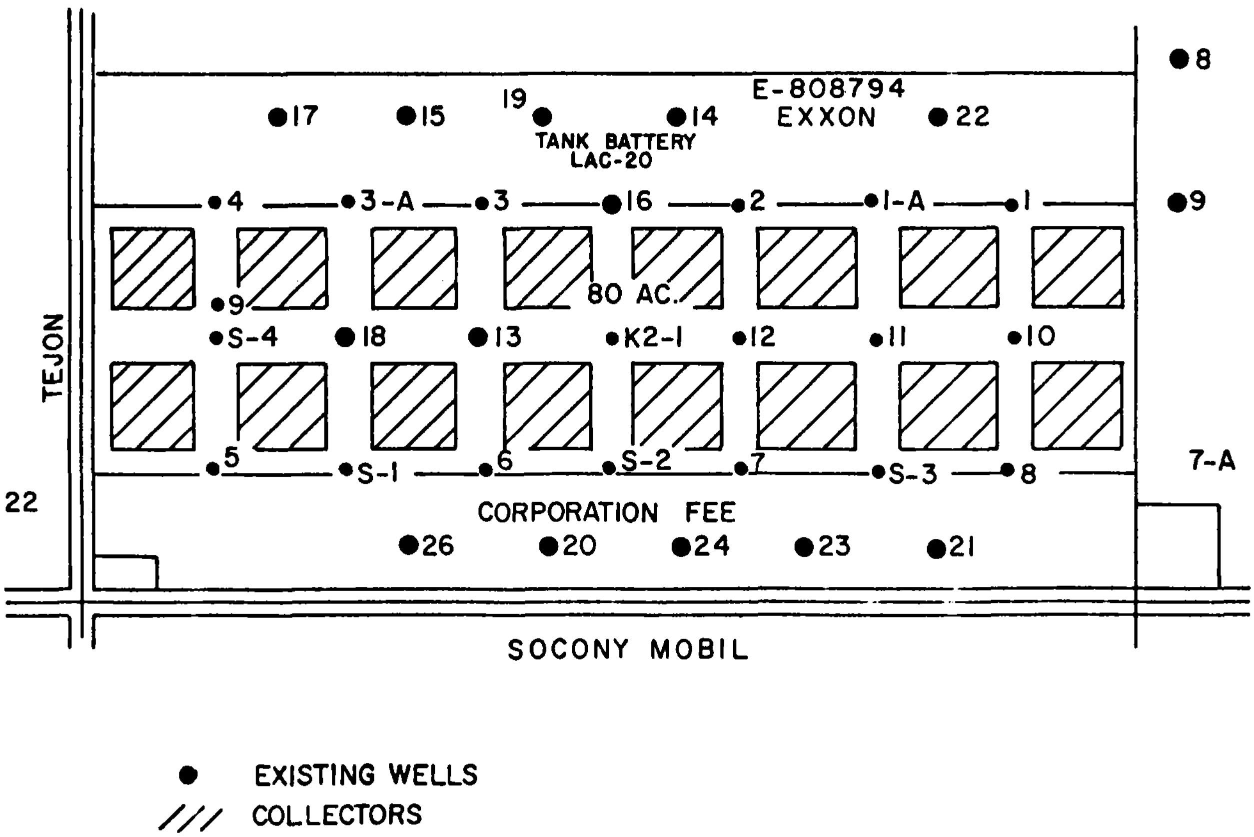
The collectors used in the conceptual designs were of the line-focusing parabolic trough type with tracking reflectors and receivers. These have proven to be the most efficient off-the-shelf collector yet tested at the Sandia Module Test Facility. As no commercially available collector was found to be significantly more effective with any one concept, calculations were performed assuming a generic performance representative of the Solar Kinetics and Suntec collectors. This performance is shown in Figure 3.3. These collectors are conceptually equal to each other and to the Acurex collector.

The collectors possess a total aperture area of 23.616 m^2 (254,208 ft^2). An aperture width of 2.52 m (8.275 ft) was assumed for the individual collectors; the collector axis-to-axis separation is assumed to be 5.3 m (17.5 ft).

3.1.2 FIELD LAYOUT OPTIMIZATION

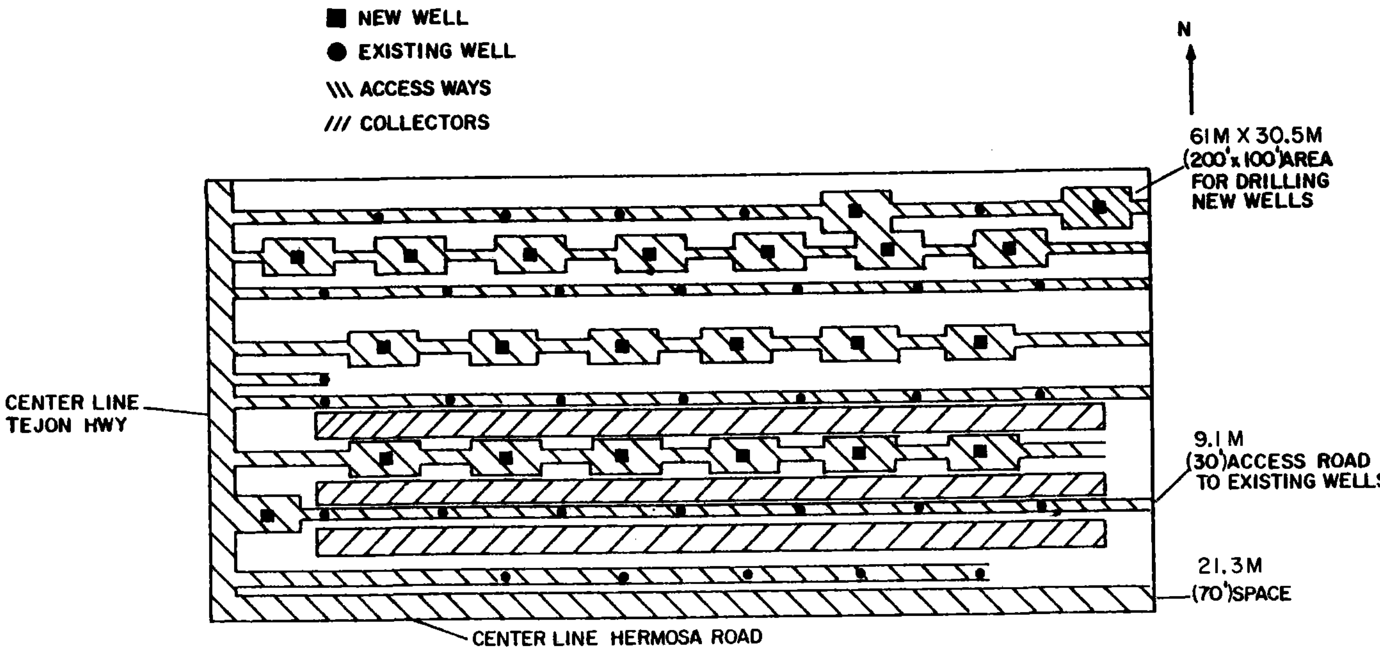
In the final design, the layout of the solar collectors and piping will be optimized with respect to the total annual energy balance, the cost of piping and the maintenance requirements of the solar thermal system. This optimization will, however, be subject to constraints imposed by the need to leave a 30-by-61 m (100-by-200-ft) area around each of the proposed new wells that will be drilled and the necessity of providing a 9-m (30-ft) access road for each row of wells. Therefore the collectors will be dispersed as indicated in Figure 3.2 rather than being laid out in the symmetrical field shown in Figure 3.1. This leads to a requirement for longer headers, a requirement that will favor the flash-separator concept.

In this study however, identical, unoptimized symmetrical fields have been used to evaluate several of the conceptual designs.



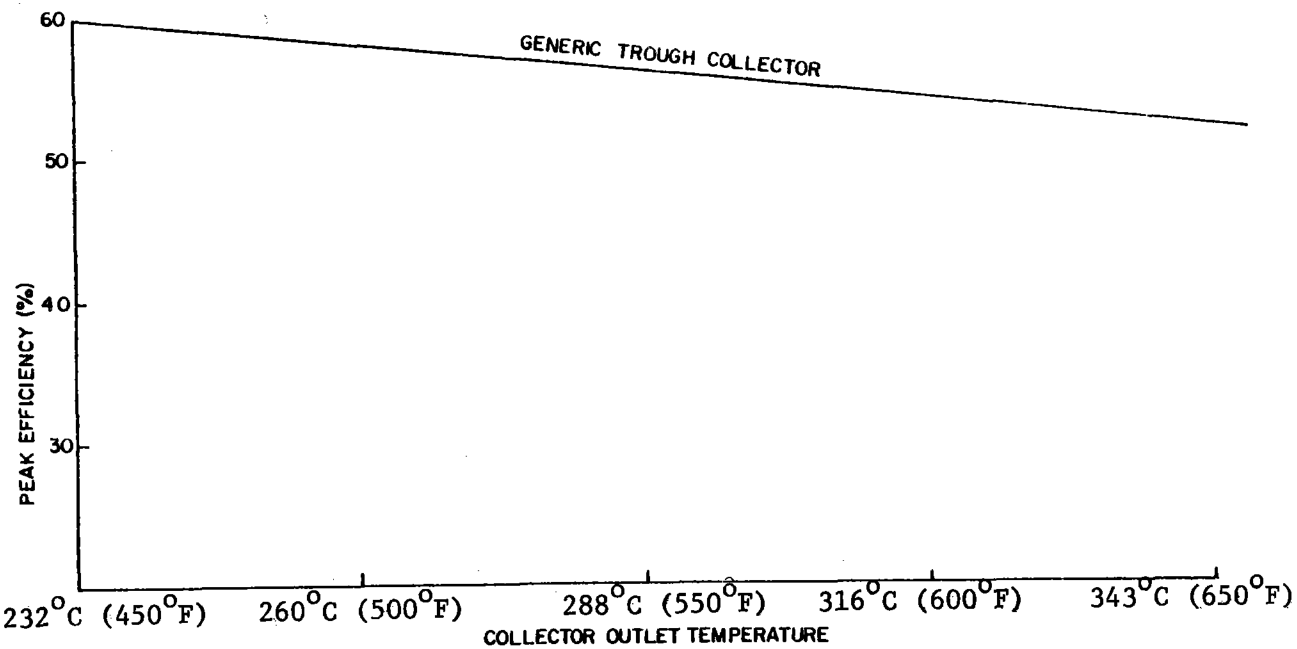
Initially Proposed Layout(Solar collectors located in the 16 blocks)

Figure 3.1



Revised Layout of Solar Collectors Showing Access Roads, Wells, and Collectors

Figure 3.2



Efficiency of Generic Trough Collector

Figure 3.3

3.1.3 CONTROL SYSTEM PHILOSOPHY

A distributed control system approach has been selected for the solar collector field. A microcomputer and associated peripheral equipment provides central supervisory control to the local collector controllers and other subsystems. A simplified block diagram of the control system for the four-block field is shown in Figure 3.4. The central controller transmits commands to the local collector controllers and receives status information from the local controllers over dedicated communication busses. The local controllers are microprocessor-based and provide local self-protection, solar tracking and status-return to the central controller.

Control and communications will be accomplished via a four-buss arrangement, providing addressing and control of individual collectors, control of a single solar collector block of 96 collectors, and control of the four separate solar collector blocks as a single group.

Control of the collectors will be based on inputs from weather instruments, field fluid temperature, flow and pressure conditions, and inputs as required from the entire oil recovery process. Control of field pumps and valves will be provided by the central controller, as required by the various operating modes.

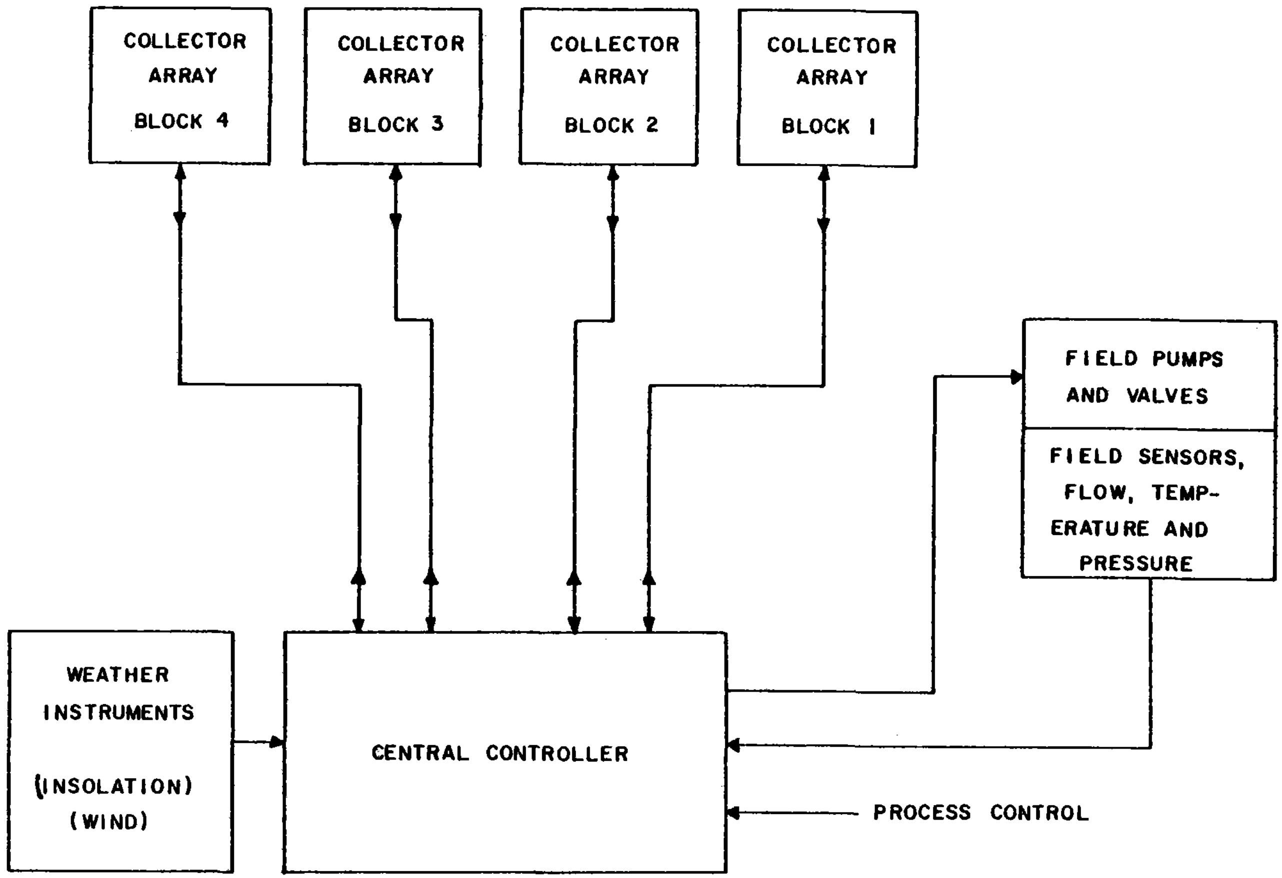
3.1.4 CENTRAL CONTROLLER

All concepts will be provided with a central controller. This will comprise a microcomputer and associated interface hardware housed in a free-standing metal cabinet, with the operator interface provided by a keyboard and CRT. A printer is also provided for hard copy data logging of field performance and conditions. An uninterruptable power supply may also be required, depending on the reliability of the on-site utility power.

The central controller is responsible for total system supervisory control. Internal algorithms are structured to provide automatic field operation for the various operating modes, self-protection of the system, servicing of operator manual controls, and field status and conditions.

Self-protection functions include:

- Monitoring status of all collector controllers
- Monitoring of field fluid flow, temperature and pressure
- Monitoring of wind speed to detect wind threat.



Control System Schematic

Figure 3.4

Field status and conditions are available to the operator on the CRT display or as a hard copy report on a prescheduled basis. This data will be a valuable aid in scheduling field maintenance. A visual inspection of the entire field would be time consuming and thus unsatisfactory operation might go undetected for a considerable period. The condition of an individual collector will be reported as operational, stowed, or in a failed condition requiring attention.

3.1.5 LOCAL CONTROLS

Controls for each collector module will be housed in a watertight box attached to the collector structure. The local controller is a microprocessor-based unit that provides orientation control to the collector, self-protection of the collector, and reports status of the controller and collector to the central controller.

The primary function of the local controller is to control the position of the collector for maximum solar energy collection. The collector is positioned by sensing the location of the concentrated solar energy beam by two photodiode sensors located on the collector receiver assembly. The output of the two sensors is equal or balanced when the collector is positioned such that the concentrated energy is centered on the receiver assembly. Any imbalance of the outputs is detected by the local controller, which commands the collector drive motor to reposition the collector. Sun tracking by this method has several advantages over other techniques: The sensors located on the receiver assembly accurately locate the concentrated beam on the receiver and no complex alignment is required; sensing of concentrated energy eliminates many problems associated with "shadow-bar" type tracking sensors caused by indirect or scattered sunlight.

The microprocessor-based local controller is programmed to drive the collector in a search pattern to find the sun, whenever the collector has been commanded to track (by the central controller). Erratic rotation of the collector caused by intermittent cloud cover, airplanes, or other disturbances is prevented by the controller, which permits only preprogrammed reasonable commands to the collector drive system.

The local controller also provides the protection function for the collector. Receiver fluid temperature is monitored, and the collector will be automatically driven to a stowed position if the temperature rises to an unsafe condition, as might result from loss of flow. The controller also drives the collector to an inverted or "stowed" position to prevent damage to the collector mirror surfaces by hail, wind, or other threatening conditions.

The status of the collector is transmitted to the central controller, on command of the central controller. Minimum status to be transmitted includes:

- o Stowed - Unstowed
- o Tracking - Out of track
- o Over-temperature - No over-temperature
- o Over-travel - No over-travel.

Each local controller has a specific serial address for request of status data. All collectors will respond to field commands to "authorize" tracking, or to "stow."

The collector is positioned by a dc motor. Bidirectional control of the motor is provided by a transistor drive circuit mounted in the local controller. The solid-state drive circuit offers improved reliability over a more conventional relay control, especially for this control application which requires numerous start-stop cycles.

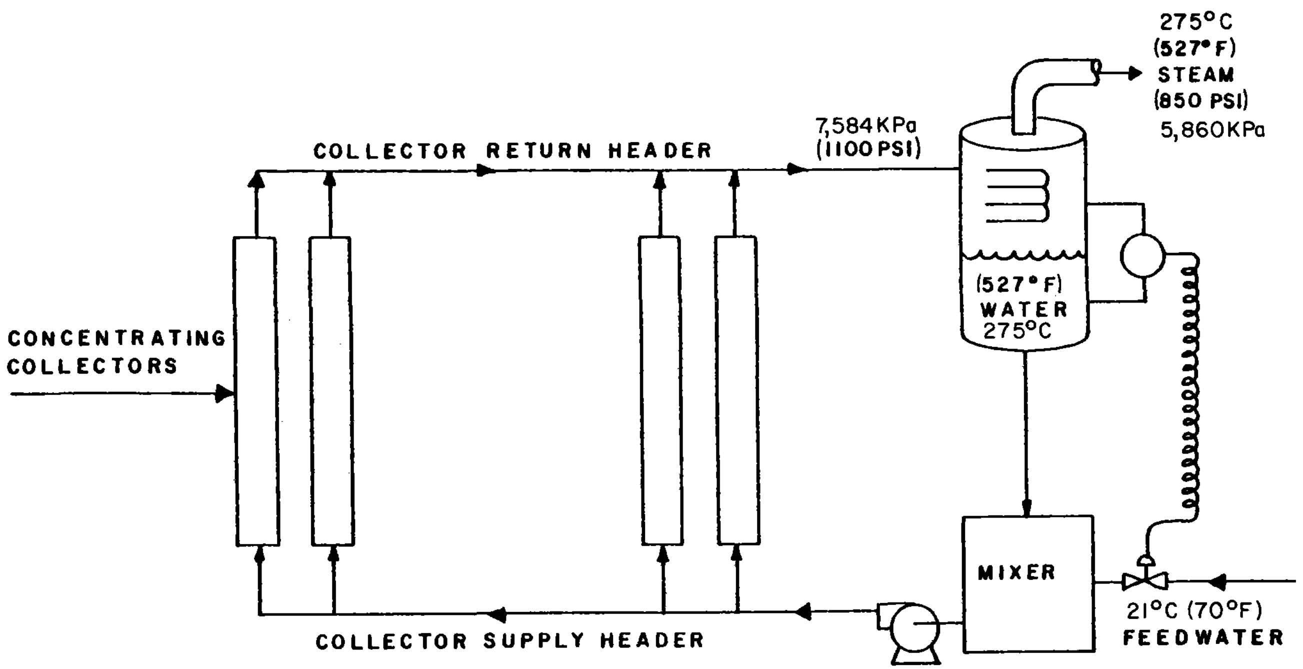
Power to the dc motor is provided by a 24-v battery located near the collector. Six to eight collectors will be powered from one battery. Batteries will be continuously trickle-charged by a battery charger. This power distribution method offers several advantages. The power to the field is a low and essentially constant 115-v load required for battery charging, thus minimizing field power wiring requirements. More important, the batteries provide an emergency power source to drive the collectors to "stow" in case of a power failure. Power failures are more likely to occur during adverse weather conditions, which may damage collectors left in an unstowed condition.

3.2 The Concepts

3.2.1 FLASH-SEPARATOR SYSTEM

The use of a flash steam separator represents one of the simplest ways of generating steam from a solar collector system. Figure 3.5 is a schematic of the system in which boiler feedwater is heated in the collectors and flashed to steam through a throttling valve. The steam is removed in a conventional steam separator.

The throttling valve is controlled both to prevent boiling within the collectors and to maintain a 290°C (555°F) receiver exit temperature while the system is operating in the steam generation mode.



Schematic of a Solar Flash Steam Separator Concept

Figure 3.5

To recover heat left in the system when insolation is no longer sufficient to maintain steam generation, provision is made for a thermal flush. When the pressure in the separator falls below 5611 kPa absolute (815 lb/in^{2}a), the water in the separator is blown down to the suction side of the boiler feedwater pump until the pressure in the separator falls to 447 kPa (65 lb/in^{2}a). Circulation of the water through the field and make up with boiler feedwater continues until this time.

The collector field for this conceptual design is laid out so that pressurized water enters the collector field along a header, passes through two collectors in series [i.e., 49 m (160 ft) of receiver tubing] and then exits to the separator via a header.

In addition to the throttle valve, feedwater, and heat recovery controls, the system is fitted with:

- o Sun intensity transmitter and recorder
- o Sun position transmitter and recorder
- o Sun intensity and position controller
- o Wind and hail alarms and shutdowns.

The plant will also be equipped with a site data acquisition system and board-mounted indicator lights. Safety devices will be included to protect against over-pressure, over-temperature, high and low water levels or any other hazardous condition. These safety devices will be read out on an alarm panel in the control room. Where required, the system will relieve the condition or shut itself down.

Not shown in Figure 3.5 is a building in which the control panel, instrument air compressor, motor control center, and site data acquisition system will be housed. Additional description of this conceptual design and the performance of the system are provided in Appendix B, Table B.1.

3.2.1.1 Operational Modes

The flash separator conceptual design allows for operation in five modes. Three of these represent normal operation, one represents freeze protection, and one represents self-protection (automatic shutdown).

Steam Generation Mode - Under conditions of peak insolation, the system is designed to generate 275°C (527°F) steam at the rate of 17,224 kg/h (37,980 lb/h). As solar radiation decreases from the peak (cosine effects), the steam flow and hence the feedwater flow decrease. Columns SG of Table 3.1 summarize the status of the system when generating steam.

Table 3.1

Flash-Separator Concept - Operational Mode Status

Component	Operational Mode* SG	CD	WU	FP
Water circulation pumps	On	On	On	On
Separator dump valves	Closed	Open	Closed	Open
Feedwater valves to each block		Liquid Level Control		

*Modes: SG = Steam generation
CD = Cool-down
WU = Warm-up
FP = Freeze protection

Cool-Down Mode - When prolonged low feedwater flow rates to the solar steam generation system indicate insufficient solar energy is being collected to usefully generate 275°C (527°F) steam, the system automatically switches into a cool-down mode. In this mode the solar collectors generate hot water that is sent to the conventional boiler as preheated feedwater. Column CD of Table 3.1 summarizes the system status when operating in this cool-down mode. Initially the collectors will be collecting solar energy (but at a poor cosine angle or diminished sun intensity) as the system cools down. After sunset the collectors will stow in their overnight position but the cool-down operation will continue, as 21°C (70°F) water is supplied and all possible energy is extracted from the hot collector fields (and separators).

When the solar energy system has been cooled down, feedwater flow to the solar fields will cease and the pumps will be shut off. Overnight and during inclement weather conditions only the fossil-fuel-fired boiler will generate steam.

Warm-Up Mode - In the morning, a wake-up sensor will detect the appearance of the sun and signal system wake-up. Given a series of affirmative signals from control sensors (i.e., low wind speed, pressure within range, fluid level within limits), the field flow pumps will start. When flow sensors detect flow, the controller will bring the collectors out of the stow position and solar collection will begin. Column WU of Table 3.1 summarizes the system status when operating in the warm-up mode.

During warm-up, insufficient solar energy will be available to produce 275°C (527°F) steam. Instead the water is circulated, under increasing pressure, until 275°C (527°F) steam is produced. At this time the transition to the steam generation mode is made and feedwater flow to the solar system begins.

Exceptions - It should be noted that the warm-up mode need not necessarily occur at sunrise, nor the cool-down mode at evening. Imperfect weather conditions can delay warm-up until the sun comes out. Furthermore, if the sky is extremely hazy or the sun is out of the clouds only a small fraction of the time, the solar energy system may operate in the cool-down mode all day, delivering preheated feedwater to the conventional boilers, but not generating steam. Therefore, the system possesses sufficient flexibility to collect and utilize the maximum amount of solar energy throughout the year.

Similarly, if the weather turns bad in daylight hours the cool-down mode will be initiated automatically.

Self-Protection Modes - The system controller, utilizing data from control sensors, protects the system from damage caused by operation outside its design range. These protection modes are:

- o Over-temperature
- o Over-pressure
- o Liquid loss.

Each collector has an individual temperature sensor/control mode for stowing itself if the temperature rises above some set upper limit. An alarm is also given that notifies the operator of a system failure. This collector set or the unit will then remain inactive (stowed) until reset by the operator (after maintenance or repair).

Each flash separator has an individual liquid-level sensor/control mode for shutting down that block of collectors if the fluid level drops below some set level. This shutdown consists of stowing the collectors and, after a brief delay (30 seconds), shutting off the pump motor. This shutdown also signals an alarm that notifies the operator that a system failure has occurred. This block of collectors will then remain inactive (stowed) until reset by the operator (after maintenance and/or repair).

Freeze Protection Mode - Water in the flash-separator system must be prevented from freezing at low ambient temperatures. This protection is automatically initiated by the temperature sensors in the solar collector field. When several measure temperatures below some preset level 1.7°C (35°F) the system controller opens valves to permit 21°C (70°F) feedwater to flow through the field. In achieving this freeze-protection the water recirculation pumps are used.

3.2.1.2 Preliminary Estimates of Capital, Operating, and Energy Costs

Preliminary estimates have been prepared for the capital costs of the flash-separator concept. These estimates are presented in Table 3.2.

Table 3.2

Flash-Separator Concept - Estimates of Capital Costs*

Item	Materials ($)	Subcontracts ($)	Direct Labor (Man-Hours)†	Direct Labor ($)§
Collectors	5,696,000		69,120	1,589,070
Flash steam separators (4)	65,800		144	3,311
Circulation pumps (4)	80,000		720	16,553
Gravel		168,000		
Foundations		796,000		
Steel (allowance)	10,000		600	13,794
Building		40,000		
Piping, valves, etc.	861,900		30,804	708,184
Instruments	231,110		27,240	626,248
Electrical	177,000		23,568	541,828
Insulation				
Pipe		434,400		
Equipment		10,000		
Painting		25,000		
Pick-Up truck and flexible hose	25,000			
Quadrant controls	40,000			
Testing	500		2,040	46,900
Field supervision, etc.	72,000			
Subtotal	7,259,300	1,473,400	154,236	3,542,907
				1,473,400
				7,259,300
TOTAL (Materials, subcontracts, and direct labor)				12,275,600
Drafting, procurement, etc.				619,000
TOTAL COST				12,894,600

*Accuracy of these cost estimates is 20%. Costs are given in December 1979 dollars.
†Assuming a productivity factor of 1.2.
§Assuming a wage rate of $10.45 per man-hour and a 120 percent overhead for indirect materials, tools, labor, supervision, and payroll burden.

These and other estimates prepared for this evaluation of conceptual design are believed to be accurate to $\pm$ 20 percent. They are based on the engineering flow diagrams (60035-1-50-I etc); the layout diagrams (Figures 3.1 and 3.2); equipment lists, sketches and data sheets. The costs of the solar collectors, their foundations and installation are those incurred at a solar industrial process heat plant under construction at Dalton, Georgia. The estimates prepared for other materials are based on vendor quotes. All costs are given in December 1979 dollars.

The quantity of useful solar thermal energy delivered was determined using Santa Maria, California, weather data and collector efficiencies, cosine losses, end losses, and shading averaged over the year. The calculations made assumed a direct normal insolation of 7.2 x 10^9 J/M^2/Yr (634,500 Btu/ft^2/yr), annual average cosine losses of 14 percent, end and shading losses of 5 percent, and a generic collector efficiency that is a function of collector outlet temperature (see Figure 3.3).

The cost of the thermal energy delivered was determined using these costs and a discounted cash flow analysis. The analysis made a series of assumptions. Chief among these are a 15-year lifespan, a requirement for a 15-percent discounted cash flow rate of return on equity, 100 percent equity funding and an effective 28.1 percent investment tax credit. These and other assumptions are detailed in Appendix B, Table B.2.

On this basis, the price of thermal engery derived from the flash-separator system was estimated to be \$31.26/10^9J (\$33.01/10^6 BTU). The results of the cash flow analysis are presented in Table 3.3.

Table 3.3 Flash-Separator Concept - Energy Costs

Solar thermal energy delivered	6.8 x 10^{13} J/yr	(64.40 x 10^9 Btu/yr)
Cost of solar thermal energy	\$31.26/10^9 J	(\$33.01/10^6 Btu)
Contributions to cost of solar thermal energy \$/10^9 Joule (\$/10^6 Btu)		
Capital	22.89	24.17
Electrical power	1.53	1.62
Maintenance	6.15	6.49

3.2.1.3 Optimization of Flash-Separator Concept

Collector Outlet Temperature - By operating in such a manner that water is flashed from higher temperatures, the fraction of water flashed can be

Table 3.4

Flash-Separator Concept - Comparison of Costs and Operation Modes for Different Collector Outlet Temperatures

Specification	Collector Outlet Temperature		
	299°C(570°F)	291°C(555°F)	282°C(540°F
Percent flashed to 596°KPa (865 lb/in^2a) and 275.2°C (527.3°F)	8.08	5.16	2.34
Total circulation (lb/h)	470,020	735,360	1,624,200
Steam flash (total, lb/h)	37,980	36,980	37,980
Header sizes (in.)	4, 3, 2	6, 4, 3	8, 6, 4
Normal pump rate (gal/min per block)	284	458	1,043
Normal discharge pressure (lb/in^2a)	1256.4	1111.1	981.6
Differential pressure (lb/in^2)	388.6	243.3	113.8
Hydraulic horsepower (hp)	64.3	65.0	69.2
Motor size (hp)	125	200	125
Cost of piping ($)	678,460	777,180	888,150
Cost of pump ($)	38,000	17,700	15,000
Parasitic power (10^6 kwh/yr)	1.75	2.103	1.75
Thermal losses (Btu/yr)*	4.85×10^9	9.15×10^9	10.51×10^9
Annual energy delivered (Btu/yr)+	67.97×10^9	64.45×10^9	63.86×10^9
Cost of energy ($/$10^6$ Btu)	30.45	33.01	33.27

*Assuming partial recovery of the heat when insolation is no longer adequate to generate steam.
+A decrease in collector efficiency of 7 percent per 100°F is assumed.

1 lb/hr = 1.26×10^{-4} kg/SEC
1 inch = 25.4 mm.
1 gal/min = 6.31×10^{-5} m^3/SEC
1 hp = 745.7 w
1 Btu = 1055.1 J.
1 Psi = 6.88 x KP_2

increased and the water circulation rate through the collectors decreased. However, this mode of operation poses two problems:

- Higher pressures are required to prevent boiling within the receiver tubes or piping. These pressures may exceed our ability to provide adequate flexible hose connectors from the receiver tubes to the distribution piping and necessitate the use of the less-efficient fixed receiver collectors.

- Higher temperatures may cause degradation of the black chrome receiver coating.

In Table 3.4, a comparison is made for collector exit temperatures of 299°C (570°F), 291°C (555°F), and 282°C (540°F). As expected the circulation rate falls with increasing temperature so that the hydraulic horsepower required remains essentially constant despite the increased pressures required to prevent flashing. Furthermore we note that lower heat losses to the atmosphere from the smaller pipe sizes required for flashing at 299°C (570°F) more than compensate for the lower collector efficiencies encountered at higher operating temperatures. Accordingly, a collector outlet temperature of 299°C (570°F) would be the logical choice if quantity and cost of energy delivered were the only factors to be considered. However, because of the increased likelihood of degradation of the receiver coatings and a possible requirement for nonstandard flexible hoses occasioned by the higher temperatures, an outlet temperature of 282°C (540°F) was judged better for this concept than 299°C (570°F) or the 291°C (555°F) of the base-case design.

<u>Heat Recovery</u> - When insolation is no longer adequate to generate steam at 5960 kPa absolute (865 lb/in^2a), heat recovery operation can begin. If the steel in the system is cooled to 149°C (300°F) and the water to 132°C (270°F), 1.53×10^{10} J (14.5×10^6 Btu) can be recovered to be used for preheating the fossil-fuel boiler feedwater. Capital costs are of course entailed in the provision of lines to carry the hot water from the separators to the fossil-fuel boiler. Two alternative means of heat recovery are:

- To blow down water from the separator to the suction side of the boiler feedwater pump at a rate such that the temperature of the resulting boiler feedwater does not exceed 121°C (250°F)

- To pump water from the separator to the outlet of the boiler feedwater pump.

In both cases, as heat recovery proceeds, water is circulated through the collector field to recover sensible heat. Because of its simplicity and the absence of the need to install reclaim pumps, only the first alternative will be considered.

The costs and effect of providing for heat recovery are shown in Table 3.5. It should be noted that if no heat recovery is provided, alternative means of providing freeze protection and blow down must be incorporated.

Table 3.5

Flash-Separator Concept - Heat Recovery

Mode of Operation	Capital Cost of Heat Recovery System ($)	Pumping Cost* ($/yr)	Overnight Heat Loss (J/yr)	Final Energy Cost ($/$10^9$ J)
Heat recovery provided	114,400	12,527	5.56×10^{12}	31.26
No provision for heat recovery	0	0	1.14×10^{12}	33.64

*These are calculated on the assumption that heat recovery requires that water be circulated through the field for 3 hours.

Hybrid Flash Separator/Water Preheat - An alternative to devoting the entire collector area to the heating of pressurized water that is then flashed is to utilize one of the four blocks of collectors to preheat the water to 198°C (388°F) and then to use this water as make-up for water flashed off as steam. This modification to the field will be examined in greater detail later. It may however be stated that with this modification greater collector efficiency can be achieved and total piping costs will be less though a penalty will be paid in increased complexity of operation, loss of redundancy and increased pumping costs in the blocks tied into the flash separators, assuming the temperature at which flashing occurs does not rise. The consequences of this alternative in terms of capital and operating costs and total energy produced are shown in Table 3.6. It is evident that preheating water offers appreciable advantages in reducing the capital costs required and enhancing the quantity of energy delivered.

Table 3.6

Comparison of Flash-Separator Concept With and Without Water Preheat

Concept	Capital Cost ($)	Energy Delivered (10^{12} J/yr)	Pumping Power Required (10^9 Btu/yr)	(kWh/yr)	Cost of Energy ($/$10^9$ J)	($/$10^6$ Btu)
Base case	12,894,000	67.95	(64.4)	2.102	31.26	(33.01)
Hybrid with preheat	12,712,000	71.59	(67.85)	2.628	29.66	(31.32)

Freeze Protection - In the flash-separator system for the generation of steam, steps must be taken to provide freeze protection while no solar energy is being gathered. This is necessary as, even if no heat recovery takes place, the temperatures in lines smaller than 7.6 mm (3 in.) fall to ambient values on overnight cooling.

Freeze protection can be accomplished by circulating water through the lines; by the installation of electric or steam tracing on piping, tubes and valves; or by draining the system. The last route would be time consuming as no natural drainage of the system is possible. Furthermore, an inert atmosphere would have to be maintained in the system to prevent oxidation of the carbon-steel pipes. This atmosphere would have to be displaced on start-up. For these reasons drainage is not recommended for use in the entire field. However, it might be appropriate for use on small portions of the field isolated for maintenance or other such purposes.

Circulation of feedwater through the system requires a small additional investment in control equipment. It further requires that provision be made to allow feedwater to be fed back to the suction side of the boiler feedwater pump after circulating through the collector field. For this the lines used for blowing down the system for heat recovery purposes could be utilized. Electrical energy would of course be consumed in this mode of freeze protection to pump the water and the circulating water would suffer a small heat loss.

The provision of electric or steam tracing entails considerable capital expenditures. Furthermore, the installation of tracing on the receiver tubes might pose many problems.

In Table 3.7, a comparison is made of the costs of providing freeze protection for various alternative arrangements of the flash separator concept. It is clear that the circulation of water through the system provides the best means of freeze protection.

Table 3.7

Flash-Separator Concept - Freeze Protection

Mode of Freeze Protection	Capital Cost ($)	Operating Cost* ($/yr)	Thermal Loss (J/yr)	10^6 BTU/yr	Final Energy Cost ($/$10^9$ J)	$/$10^6$ BTU
Circulate boiler feedwater	114,400**	7158	2.7×10^9	(2.56)	31.26	(32.91)
Electric tracing	1,633,600	1350	0	(0)	37.33	(39.29)
Steam tracing	2,164,520	0	1.48 x 10"	(140.28)	38.64	(40.67)

*From steam/circulated water. Based on 400 hours protection required each year.

**This assumes that lines between the separation and the suction side of the feedwater pump are provided solely for freeze protection. In reality they are justified for heat recovery purposes.

Thermal Storage - No provision has been made for thermal storage for the purpose of steam generation within any of the conceptual designs. The designs are based on the assumptions that:

- o All the steam generated, even under conditions of peak insolation, can be immediately injected into wells without any harmful consequences to the wells or to the potential for oil recovery
- o Lower levels of steam generation (as would occur under partial or total cloud cover of the collector field) are equally acceptable.

If these assumptions do not hold, other modes of operation of the oil-fired steam generators provide an alternative to the provision of costly thermal storage facilities or the operation of the solar system at less than its full potential. In particular, provision can be made for the storage of preheated boiler feedwater; this is discussed later.

Pipe Sizes - The selection of satisfactory pipe sizes requires consideration of the heat losses incurred, parasitic energy losses, and piping and pump capital costs. In addition, standard industrial practice requires that the fluid velocity be kept below 3 m/s (10 ft/s) as higher fluid velocities adversely affect the piping support structures.

Calculations were performed for three sets of pipe sizes for a 291°C (555°F) collector outlet temperature. In Table 3.8, pump power and piping and pump capital cost for these sets of pipes are presented with an assessment of the changes in the total annual energy balance and the resulting costs of energy that are occasioned by the selection of pipe sizes. Another set of pipes of smaller diameter 10.2, 7.6, and 5.1 mm (4, 3, and 2 in.) was not considered further as the resulting velocities were too high: 4.1, 3.6, 4.0 m/s (13.4, 11.7, and 13.1 ft/s) in the 10.2, 7.6, and 5.1 mm (4, 3, and 2 in.) lines respectively).

From these calculations, it is evident that the set of pipe sizes incorporated in the basic design for the flash separator concept is superior to the other sets considered. As only 6 percent of the differential pressure across the pump in the base case can be ascribed to frictional losses, increasing pipe size will result only in higher capital costs and heat losses and not in reduced pumping cost.

Number of Separators - The base-case design proposes that each of the four collector blocks be provided with a steam separator. An alternative is to utilize a single separator and circulation pump for the entire collector field. The advantages of this alternative are:

- o Total separator and pump capital costs are lowered
- o Piping requirements for heat recovery are greatly diminished.

The disadvantages are:

- o Costs of piping for the pressurized water circuit are higher
- o Slightly larger pressure drops would be incurred, perhaps increasing parasitic power requirements and increasing the pressure to which the flexible hoses and piping would be subjected
- o Unavailability of the single larger pump and separator would lead to shut-down of the entire system. However, this will only adversely affect the overall availability of the system if the unavailability of the large pump and separator exceeds that of the small pumps and separators. In FWDC's experience this is not the case; the availability of the system is anticipated to be independent of the number of pumps and separators. Details of the availability calculations are provided in Appendix B, Explanation B.1.

Table 3.8

Flash Separator System - Comparison of Pipe Sizes

Pipe Size Set mm (in.)	Fluid Velocity m/s (ft/s)	Pumping Power Required w(hp)	Cost of Pipes and Pump ($)	Energy Losses to Atmosphere* 10^{12} J/yr (10 BTU/yr)	Cost of Energy $\$/10^9 J$ ($\$/10^6$ BTU)
152.4(6)	19.4(5.92)	1.12×10^5 (150)	752,000	6.88(6.52)	31.26(33.01)
101.6(4)	22.02(6.71)				
76.2(3)	19.16(5.84)				
203.2(8)	11.09(3.38)	1.12×10^5 (150)	905,000	9.25(8.77)	32.48(34.3)
152.4(6)	9.71(2.96)				
101.6(4)	10.99(3.35)				

*Heat losses from distribution piping alone. These losses assume heat recovery takes place.

As the actual collector layout in the Edison field must differ from that incorporated in the proposal (Figures 3.1 and 3.2), the options provided by altering the number of separators and pumps have not been costed at this stage.

3.2.1.4 Problems With Flash-Separator Concept

Safety - The safety problems associated with the flash-separator concept result from the use of pressures of 7580 kPa absolute (1100 lb/in^{2}a) and the possible occurrence of higher pressures. Two problems are of particular concern:

- o Fatigue failure of the flexible hoses connecting the receiver tubes to the distribution piping
- o Catastrophic failure of isolated receiver tubes that are exposed to concentrated solar radiation while filled with water.

The consequences of these failures are ameliorated by the following factors:

- o There is little likelihood of operating personnel being in the vicinity should a failure occur.
- o Hose failure tends to result in leaks rather than in catastrophic failures with high steam/water discharge rates.

The probability of the occurrence these problems can be reduced by the following steps:

- o A test program can determine the fatigue life of the flexible hoses; the probability of failure will be minimized in the final design.
- o Pressure relief valves will be installed on the collectors to prevent over-pressure, even if the collectors are isolated. In addition, the collector controls will stow the collectors if the fluid temperature is too high.

We therefore conclude that no great safety problems are posed in the flash-separator concept.

Flexible Hoses - In tracking the sun and in moving to a stow position, the receiver tube of a parabolic trough collector moves through an arc of 5 radian (270 deg) at a radius of 6 m (2 ft) from its center of rotation. Metal hoses can be used to carry the heat-transfer fluid between the receiver and the field distribution piping, alone or in conjunction with rotary swivel joints. However, swivel joints have proved unsatisfactory and metal hoses have been prone to premature failure, presumably because of repeated flexing at a small radius of curvature and from torsion. This torsion is induced by squirming and by the thermal expansion and contraction of the receiver tubing and distribution piping in directions at right angles to each other. It should be noted however that premature failure is not catastrophic; rather it results in leaks. These leaks are often difficult to detect.

To absorb the linear expansion/contraction of the piping and receiver tubes the use of bellows or additional hoses has been proposed. However, these approaches may result in the shading of the collectors and require additional capital expenditure for the bellows and hoses and for their support structure. Sandia has concluded that a single insulated hose will likely provide the most economical solution to this problem. To provide hoses that can meet the requirements of handling heat-transfer fluids at 343°C (650°F) and 2,410 kPa absolute (350 lb/in^2a), Sandia has initiated a development program. It is anticipated that this will result in hoses that can operate over the 15,000 cycles that are expected to occur in a system's 15-year life span. However, the flash separator concept operates at even higher pressures and thus a potential problem is whether hoses can also be developed that will both withstand the 7580 kPa absolute (1100 lb/in^2a) working pressure of this system and not suffer from premature failures.

The high-pressure flexible metal hoses that will be required for such service are subjected to three kinds of loads: pressure, bending moment, and torque. Bending moment and torque are caused by the movement of the receiver tube through the 5 radian (270 deg) arc, squirming and the thermal expansion of the tubes and pipes. The values of the bending moment and torque depend upon the flexibility of the metal hose. The metal hoses can be made to effectively resist the hoop stress (caused by pressure) and bending stress, but they are weak in torsion. The torque can be reduced by increasing the length of the hose; however, this will increase the cost. For use with flash-separator concepts, a flexible hose of 31 mm (1-1/4 in.) O.D. with two braids made of Type 321 stainless steel would appear to be adequate. At room temperatures this hose has a working pressure of 13,800 kPa absolute (2000 lb/in^2a) and a burst pressure of 55,100 kPa absolute (8000 lb/in^2a). At 291°C (555°F) these pressures will be reduced by 20 percent. The length of the metal hose must be determined from cost, torsional stress, and fatique considerations. In this evaluation, the only major technical uncertainity is the fatigue life. To determine this, accelerated tests are required.

We can therefore conclude that hoses are available for use in the flash-separator concept but that a test program is required before their design can be finalized.

Water Chemistry - Poor quality feedwater can lead to corrosion, pitting and fouling. Of particular concern, since it caused problems in Sandia's SLATS test program, is iron contamination, the result of a cycle of corrosion and deposition. Iron contamination may occur as a result of allowing oxygen-rich water to stand in the system following hydrostatic tests or from oxygen damage and pH abnormalities when the system is in service.

As the present boiler feedwater at the Edison field (Table 3.9) would appear to be of adequate quality for the flash-separator concept, we believe that corrosion and fouling problems will originate only as a result of upsets in the water treatment system or mistakes in installation, operation, and maintenance.

For example, water pH may be lowered precipitously through the leakage into the water of acids used to regenerate iron-exchange resins. These and other such problems will be addressed in the failure analysis to be performed as part of the preliminary design task.

Table 3.9 Quantities of Impurities Found in Water at Exxon's Edison Oil Field (ppm)*

Impurity	As Produced From Well	After Treatment
Calcium	54.50	0.5
Magnesium	12.60	0.5
Sodium	50.60	210.0
Bicarbonates	298.90	
Chlorides	36.10	
Sulphates	2.20	
Nitrates	0.44	
Total hardness as $CaCO_3$	187.66	<0.5

*Dissolved oxygen is removed by the injection of hydrazine. The pH of the water was 7.4 before treatment and 9.0 after treatment.

The question of blow down will also be addressed in the preliminary design stage. It should be noted, however, that the concentrations of impurities will be lowered when the system is in the cool-down mode of operation.

Freezing - The freezing of water within the lines, pumps and separator is possible when ambient temperatures fall below 0°C (32°F). Freezing may of course result in the bursting of these lines and equipment. It is more a problem overnight or when no water flows through lines in daylight hours. A variety of means are adequate to prevent freezing; their failure will result from component failure or operator error. These possibilities will be examined in the failure analysis.

Subcooled Boiling - Subcooled boiling can occur if the receiver tube metal temperature exceeds the boiling point of the water. This boiling results in the formation of bubbles that will collapse in the main flow of fluid resulting in an additional pressure drop and possible pitting of the receiver tubes should concentration of chemicals occur as a result of boiling.

Our calculations indicate that the water flows through the receiver tubes at a mean velocity of 0.73 m/s (2.39 ft/s). This translates into a Reynold's number of 1.91×10^5, a waterside heat-transfer coefficient of 2162 W/m^2K (1250 Btu/h/ft/°F) and a water skin temperature of 293°C (560°F) at the collector exit. This will result in subcooled boiling near the exit but because of the highly turbulent flow it is anticipated that no accumulation of chemicals is possible in the boundary layer and that the bubbles will collapse once they emerge from the thin boundary layer. It will, however, be important to avoid fouling of the receiver tubes. Should solids levels in the water be too high, a porous scale will form. Water will permeate this and boil, and as a result, corrosion may occur.

More extensive subcooled boiling and possible corrosion may also be occasioned by the gross maldistribution of flow through the tubes. Such maldistribution will however be manifested through abnormal receiver temperatures that will be detected.

Black Chrome Receiver Coatings - The temperature maintained on the outside of the receiver coating is a function of the solar heat flux, heat losses, temperature, and turbulence of the water circulating through the tubes and the fouling on the inside of the tubes. For normal operation of the base case flash-separator concept, with a collector temperature of 291°C (555°F), a receiver coating temperature of 296°C (565°F) is expected at the exit to the collector, though this temperature would rise if extensive fouling occurred.

Current receiver tubes have black chrome coatings. These coatings have proven susceptible to rapid degradation at temperatures above 288°C (550°F). While Sandia personnel assert that little degradation should occur in black chrome receiver coatings at temperatures below 349°C (660°F) (provided the humidity is not too high and the initial coating is stable), consistent coating stability has not been attained with electrodeposition methods outside the laboratory. Sandia personnel expect to have this problem resolved by October 1980 and other plating companies claim they can produce stable coatings. Alternatively, other methods such as the use of molten dichromate can be used to create stable black chrome coatings. Thus we anticipate that the stability of receiver coatings should pose no great problems for collectors installed after 1980 if the flash separator concept is adopted.

This notwithstanding, it is our intention to operate at low receiver temperatures as much as possible. In addition, operating procedures will be designed to prevent exposure of the receiver tubes to intense solar radiation without water flow through the tubes.

3.2.2 HYBRID UNFIRED BOILER/FEEDWATER PREHEAT SYSTEM

The simplified system schematic (Figure 3.6) shows the conceptual design for this concept. For simplicity, auxiliary equipment is not shown. The basic concept for this system is to utilize solar thermal energy for both preheating boiler feedwater and generating steam. This is accomplished by collecting solar thermal energy in the preheat solar block to preheat 21°C (70°F) feedwater to 198°C (388°F). This water is then pumped to three solar boilers where steam is generated and injected into the boiler system steam line. The necessary heat of vaporization is produced from the remaining three solar collector blocks. These blocks use Dowtherm LF as a heat-transfer fluid to carry the collected solar thermal energy from the collectors to the unfired boilers.

3.2.2.1 Process and Instrumentation Description

Drawing 53857-1-50-1 (Appendix B) shows the collector field arranged in four blocks. One of these blocks directly preheats the water fed to the other three in which steam is generated for oil well injection.

Each of the three steam generation blocks is furnished with a Dowtherm circulation pump, Dowtherm expansion tank and steam generator. Feedwater to the solar system is taken from the existing boiler feedwater pump and routed to the solar block used to preheat the water.

A booster pump picks up the preheated water from the preheat block to send it to the three steam generation blocks. The flow rate is controlled by level controllers located on the shell side of each of the three steam generators.

The system will be fitted with a series of controls for the solar collectors. These are identical to those described for the flash separator concept.

One other significant control concerns the water outlet temperature from the preheat block. If, for example, cloud cover reduced the ability of the steam generation blocks to accept feedwater from a preheat block still under full solar radiation, the preheat temperature will rise to the point where boiling could occur in the preheat zone. Before this can happen, the temperature recording control (TRC) at the outlet of the preheat zone will open, diverting the hot feedwater to the existing fired boiler.

In addition to the principal controls described above and shown on Drawing 53857-1-50-1(Appendix B), the plant will be equipped with a site data-acquisition system, board-mounted indicator lights, and safety devices to prevent hazardous conditions. These include a fire protection system that incorporates a water main with hydrants looping around the collector field.

Additional details of the equipment incorporated in this conceptual design are provided in Appendix B, Table B.1.

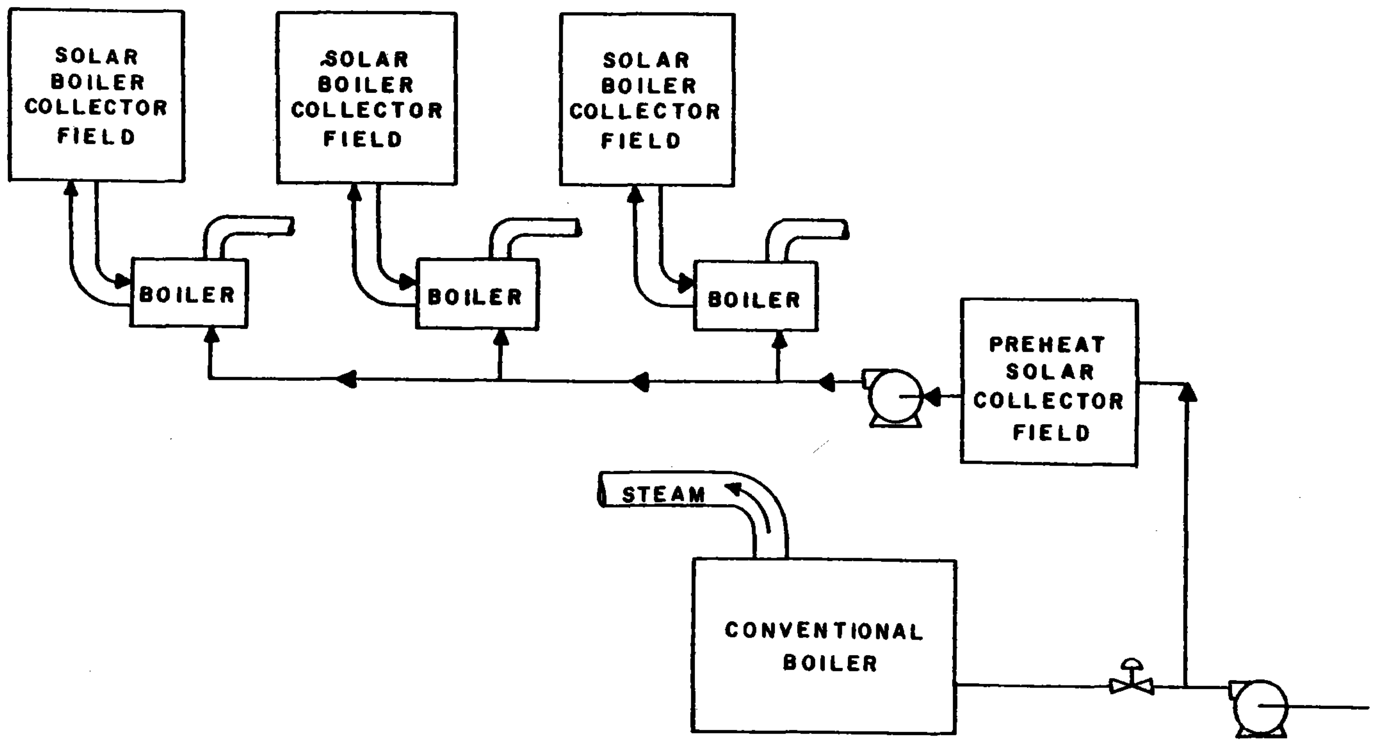
The steam generator collector field is laid out so that a central header runs between the rows of collectors; all the collectors are placed in parallel.

3.2.2.2 Operational Modes

The hybrid concept exhibits five operational modes, three of which represent normal operation; one represents freeze protection and one represents a self-protection mode. Components referred to in this section are shown on Drawing 53857-1-50-1 (Appendix B).

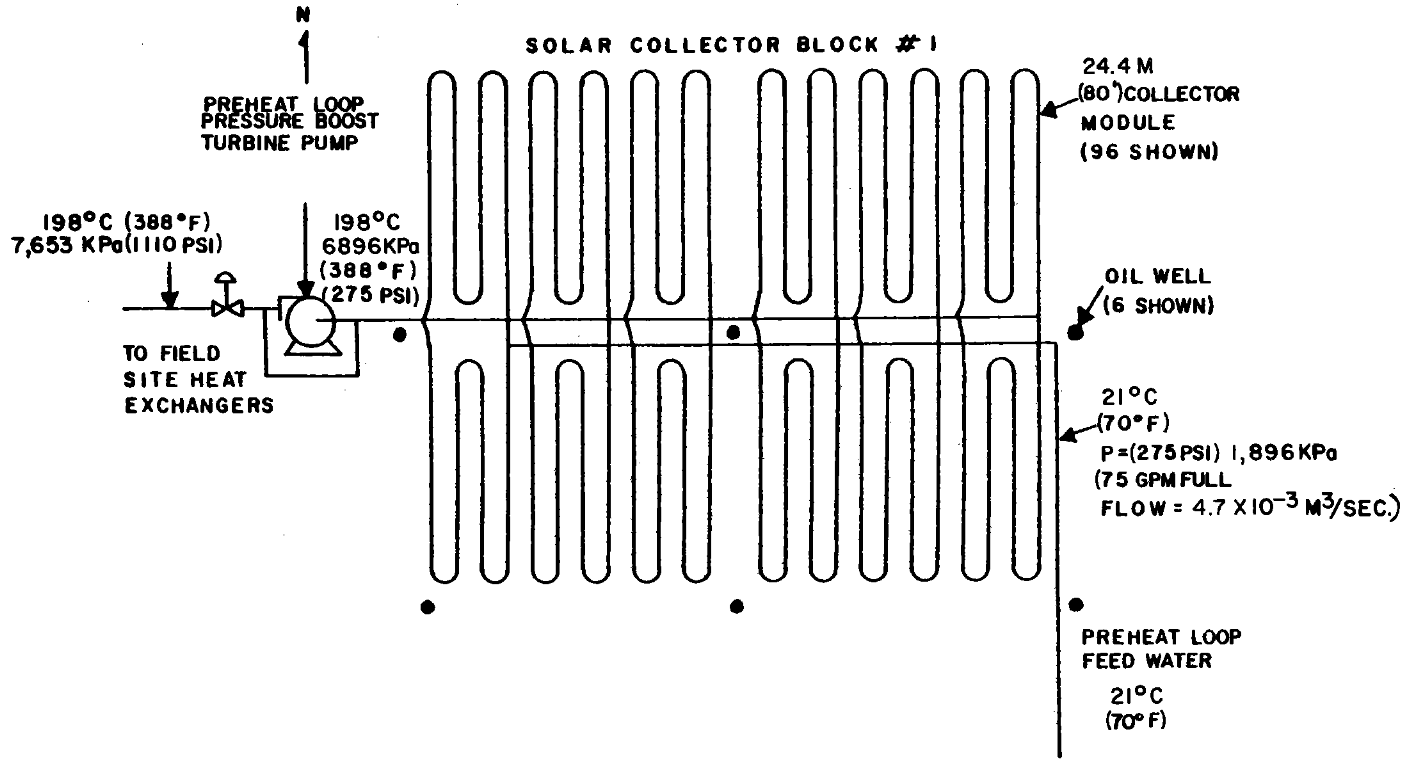
Steam Generation Mode - During normal peak sunshine conditions, the system generates 275°C (527°F) steam at the rate of 17,272 kg/h (38 x 10^3 lb/h). Feedwater flow to the solar field is 0.005 m^3/s (75 gal/min). As solar radiation decreases from the peak, the feedwater flow is decreased to allow continued generation of 275°C (527°F) steam and thus steam flow will decrease. Column SG of Table 3.10 summarizes the system status when operating in the steam generating mode.

Cool-Down Mode - When insufficient solar energy is collected to generate 275°C (527°F) steam, the system automatically switches into a cool-down mode. Column CD of Table 3.10 summarizes the system status when operating in this mode. Upon completion of cool-down the pumps are switched off unless freeze protection is required.



Combination Feedwater Preheat and Solar Steam Boiler Concept

Figure 3.6



Preheat Loop Piping Layout

Figure 3.7

Table 3.10

Unfired Boiler/Feedwater Preheat Hybrid - Operational Mode Status

<table>
<tr><th rowspan="2">Component</th><th colspan="4">Operational Mode*</th></tr>
<tr><th>SG</th><th>CD</th><th>WU</th><th>FP</th></tr>
<tr><td>Solar boost pump</td><td>On</td><td>On</td><td>On</td><td>On</td></tr>
<tr><td>Circulating pumps</td><td>On</td><td>On</td><td>On</td><td>Off</td></tr>
<tr><td>Reclaim pumps</td><td>Off</td><td>On</td><td>Off</td><td>On</td></tr>
<tr><td>Solar feedwater valve</td><td>Open</td><td>Open</td><td>Open</td><td>Open</td></tr>
<tr><td>Unfired boiler feedwater control valves</td><td></td><td colspan="2">Liquid Level Control</td><td></td></tr>
<tr><td>Boiler dump valves</td><td>Closed</td><td>Open</td><td>Closed</td><td>Open</td></tr>
<tr><td>System controller</td><td>Active</td><td>Active</td><td>Active</td><td>Active</td></tr>
</table>

*Modes: SG = Steam generation
CD = Cool-down
WU = Warm-up
FP = Freeze protection

Warm-Up Mode - Upon sunrise, the system begins to operate in the warm-up mode. Column WU of Table 3.10 summarizes the system status when operating in the warm-up mode. In this mode of operation preheated water is diverted to the fired boiler until the solar steam generators are able to accept feedwater.

During warm-up, insufficient solar energy will be available to produce 275°C (527°F) steam. Therefore, the preheated feedwater will be returned to the conventional boiler. The oil warming up in the solar boiler loops will increase in temperature until the water in the solar boiler begins to boil. At this time the boilers will call for feedwater and the preheated feedwater will be fed to the boilers. The system then switches to the steam generating mode.

Exceptions - The exceptions noted in the description of the operation of the flash separator concept also apply to the hybrid concept.

Freeze Protection Mode - Water in the solar thermal enhanced oil recovery system must be prevented from freezing when freezing temperatures occur at the site. This protection is automatic and is initiated by the temperature sensors in the solar collector field. When ambient temperatures below some preset level e.g., 2°C (35°F) are reached, the system controller opens valves to permit the 21°C (70°F) feedwater to flow throughout the field. This feedwater will warm the collectors in the preheat field, warm the feedwater in the solar boilers, and warm all feedwater lines.

The heat-transfer fluid in the solar boiler fields need not be heated since it can be pumped at temperatures below the minimum extreme at the site. This mode of operation is described in Column FP of Table 3.10.

Self-Protection Modes - These modes of operation are similar to those described for the flash-separator concept.

3.2.2.3 Preliminary Estimates of Capital, Operating, and Energy Costs

Preliminary estimates for the capital costs of the hybrid concept are presented in Table 3.11. Using these and the assumptions detailed in Appendix B Table B.2, the price of solar thermal energy delivered is estimated to be $\$31.63/10^9$J ($\$33.40/10^6$ Btu). The results of the cash flow analysis are presented in Table 3.12.

3.2.2.4 Optimization of Hybrid Unfired Boiler/Feedwater Preheat Concept

Flat-Plate Collectors - In response to an inquiry by Aerospace Corporation, use of flat-plate solar collectors for preheating the boiler feedwater was evaluated. In this evaluation, the efficiency, cost, reliability and ease of maintenance of flat-plate collectors were compared with those of parabolic trough

Table 3.11

Unfired Boiler/Feedwater Preheat Hybrid--Estimates of Capital Costs

Component	Materials ($)	Subcontracts ($)	Direct Labor Man-Hours*	Direct Labor ($)†
Collectors	5,696,000		69,120	1,589,070
Dowtherm expansion tanks (3)	41,700		108	2,483
Dowtherm storage tank (1)	18,100		48	1,104
Steam generators (3)	120,000		126	2,897
Circulation pumps (3)	33,000		144	3,311
Booster pump (1)	12,200		72	1,655
Reclaim pumps (3)	120,000		216	4,966
Dowtherm change pump (1)	3,100		36	828
Gravel		168,000		
Foundations		896,000		
Steel (allowance)	10,000		600	13,794
Building		40,000		
Piping	877,510		47,580	1,093,864
Instruments	219,440		32,868	755,635
Electrical	178,700		23,724	545,414
Insulation				
Pipe		548,880		
Equipment		44,000		
Painting		25,000		
Pick-Up truck and flexible hose	25,000			
Quadrant controls	40,000			
Testing	1,000		3,000	68,970
Field supervision, etc.	60,000			
Dowtherm	84,000		120	2,759
Subtotal	7,539,750	1,721,880	177,762	4,086,748
				1,721,880
				7,539,750
TOTAL (Materials, subcontracts, and direct labor)				13,348,000
Drafting, Procurement, etc.				682,000
TOTAL COST				14,030,000

*Assuming a productivity factor of 1.2.
†Assuming a wage rate of $10.45 per man-hour and a 120 percent overhead for indirect materials, tools, labor, supervision, and payroll burden.

collectors. In particular, the following purported advantages of flat-plate collectors were studied:

- o Flat-plate collectors may be more efficient than concentrators at low temperatures
- o Flat plates collect total radiation (direct and diffuse), while concentrators collect only direct radiation
- o Flat-plate collectors are simpler and more reliable than tracking collectors
- o Flat-plate collectors may be cheaper than tracking, concentrating collectors.

Table 3.12

Unfired Boiler/Feedwater Preheat Hybrid--Energy Costs

Solar thermal energy delivered	70.7×10^{12} J/yr	(67×10^{9} Btu/yr)
Cost of solar thermal energy	\$31.63/10^9J	(\$33.40/10^6 Btu)
Contributions to cost of solar thermal energy \$/10^9 Joule (\$/10^6 Btu)		
Capital	21.07	(22.25)
Electric power	0.55	(0.58)
Maintenance	6.23	(6.58)

Following the assessment of these four points, citing previous conclusions drawn by Treadwell:(3-1)*, we can state that:

- o Current flat plate collectors are more efficient (peak data) than concentrators only at temperatures below 49°C (120°F). At the Fresno, California, latitude the performance "breakeven" temperature for tilted flat plates and N-S oriented parabolic troughs is 48°C (118°F). Above 49°C (120°F), the efficiency of flat plate collectors drops rapidly. Furthermore, away from from conditions of peak insolation, fixed flat plate effi-

*See reference section.

ciencies decrease faster than tracking collectors' efficiency implying that efficiency gains cannot be realized at all times unless the collectors are operated at temperatures of the order of 38°C (100°F) or below. Preheating from 21°C (70) to 38°C (100°F) supplies only 2.6 percent of the energy needed to generate 275°C (527°F) steam. Thus, the substitution of flat-plate collectors gains a very small increment of efficiency on only 2.6 percent of the total energy produced.

- Reviewing the insolation data compiled by Boes et al. of Sandia Laboratories (B-2) total annual insolation (on a latitude tilted surface) at Santa Maria, California, is estimated to be 1.3 times the direct normal radiation (on a north-south axis tracking trough). This is insufficient to compensate for the tracking capability of the troughs; the optical efficiency of the flat-plate collector compensates only partially for the thermal efficiency of the concentrators discussed above.

- Generation of 7.32 MW (25 x 10^6 Btu/h) of 275°C (527°F) steam requires that a large number of tracking concentrating collectors operate accurately and reliably. The substitution of simple flat-plate collectors for a very small portion of this collector field will not add to system reliability or in any way guarantee system success. To the contrary, the "mixed" collector field will add complexity, and probably reduce system reliability.

- Currently, concentrating collectors are being quoted at around $\$214/m^2$ ($\$23/ft^2$) at the factory while the best flat plate collectors are sold at $\$1.49/m^2$ ($\$16/ft^2$). Assuming installation costs of about $\$.46/m^2$ ($\$5/ft^2$), the cost advantage of flat plate collectors is not sufficiently significant considering the arguments cited above; that is, only a very small fraction of the field (2.6 percent) can be substituted, the efficiency gains are small, and the mixed collector field imposes additional complexity and reduced system reliability.

Accordingly we have not incorporated any flat-plate collectors into any conceptual design, and conclude that no further study of this alternative to our conceptual design is warranted. The performance of current evacuated-tube-type collectors was also examined. Although they exhibit efficiencies higher than flat-plate collectors for temperatures above 93°C (200°F), they provide less efficiency than tracking parabolic troughs for all temperatures. Therefore, they were not included in any conceptual design and will not be studied further.

Boiler Type - The boiler produces saturated steam by exchanging heat between the hot heat-transfer fluid and feedwater. In view of the small proportion of the project's cost that can be assigned to the boiler cost (0.9 percent of capital costs), reliability and ease of maintenance and control are the features that must be emphasized in selecting a boiler type. In this study of alternatives to the base-case design, once-through, forced recirculation, and natural-recirculation drum-type boilers were considered.

The once-through boiler possesses certain distinct advantages over drum and kettle-type boilers:

- It is capable of fast responses, start-up, and shut-down
- Even rapid fluctuations do not create a danger of circulation disturbances
- The thermal storage capacity of the boiler is small; potential overnight heat losses are therefore also smaller.

However, it also possesses overwhelming disadvantages for service in this project:

- It requires demineralized and well-deaerated feedwater as all particles entering the boiler must leave with the steam or fall out as deposits. Alternatively the provision of a separator vessel at the end of the evaporator section may suffice (in which case the boiler is no longer truly "once-through" if this water is recirculated).
- Control requirements of the once-through boiler are demanding. They require the feedwater rate to be determined by the anticipated heat-transfer rate or some other such variable.
- To ensure proper flow distribution and stability, a high water/steam mass velocity is required. This requirement results in a high pressure drop and a restriction to a minimum permissable boiler load of 30 to 40 percent of full load. This in turn may impede operation of the boiler under conditions of low insolation.
- This boiler type would need to be custom designed.

Accordingly the once-through boiler will not be considered further.

In contrast to the natural circulation boiler, a forced-recirculation drum-type boiler requires a pump and hence has inherently lower reliability, higher power consumption, and requires additional maintenance. Forced recirculation is unnecessary at the low heat-flux densities and low operating pressure anticipated here. Therefore, we can conclude that forced recirculation boilers possess no advantages over the natural circulation boilers specified in the base-case conceptual design.

Natural-circulation boilers are either of the drum or kettle type. The drum type requires a tubular heating section which is separate from the steam/water-separating drum. The drum and heating sections must be connected by exterior downcomer piping, resulting in a relatively costly assembly. In the kettle type, tubes containing the hot heat-transfer fluid are submerged in the boiler water that partially fills a horizontal, cylindrical pressure vessel. Steam/ water separation takes place in the upper portion of the vessel above the water level. This boiler type is inexpensive and readily available from many manufacturers. It is particularly well suited for the operating pressure contemplated and has adequate response. Because of these desirable features the kettle-type natural-circulation boiler has been selected for the proposed solar steam plant.

Heat-Transfer Fluids - Though for the base-case design Dowtherm LF was selected as the heat-transfer fluid, many other heat-transfer fluids are available. The selection of an appropriate heat-transfer fluid is a major factor in determining the viability of unfired boiler concepts for solar thermal enhanced oil recovery. This selection should be made on the basis of technical feasibility and cost and environmental and safety considerations.

There are three basic performance criteria on which a solar collector fluid can be judged:

- Can the fluid handle the heat flux without adversely affecting on system performance or the fluid?
- Can the fluid be pumped under operating conditions without excessive power requirements?
- How will the fluid be pumped at the site's minimum start-up temperatures?

Costs associated with the heat-transfer fluids arise from:

- The cost of the initial fluid
- Replacement costs for degraded, vented, and spilt fluid

- Pumping costs

- The effect of the heat-transfer fluid upon the size of the heat-transfer surfaces, lines, and pumps.

Safety and environmental concerns relate to:

- The flammability (flash point and auto-ignition temperature) and the vapor pressure of the fluid

- The fluid's toxicity and biodegradability.

A series of heat-transfer fluids have been examined for use in this project. Their properties are listed in Tables 3.13 and 3.14.

Before discussing the individual fluids, let us first list those properties that would be desirable:

- Low viscosity

- High thermal conductivity

- Easily pumped at -7°C (20°F) (the lowest temperature recorded at the Edison field)

- Low breakdown rate. Degradation is accompanied by the appearence of volatile and/or high-boiling materials. Low-boiling materials may cause excessive venting and high make-up rates; high-boiling materials cause high viscosities, accelerated fluid degradation and fouling of tube surfaces.

The formation of polymeric degradation products and the fouling of tube surfaces are particularly undesirable events in that the fouling of the receiver tubes may result in excessively high receiver coating temperatures. These in turn may cause degradation of the coating.

The fluids will now be evaluated for service in the unfired boiler concepts. These entail a collector exit heat-transfer fluid temperature of 299°C (570°F). Calculations to compare the heat transfer and pressure drop characteristics of the fluids are presented in Appendix B (Explanation B.2); a discussion on degradation appears in Appendix B (Explanation B.3). All fluids have acceptable heat-transfer properties.

Table 3.13

Comparison of Heat-Transfer Fluids

Heat-Transfer Fluid	Safety/Environmental* Flash Point	AIT	Vapor Pressure 570°F (lb/in^{2}a) 299°C	Operating Temperature Range	Viscosity (Cp) (24°F) -4°C	(570°F) 299°C	Density (lb/ft^2) (570°F) 299°C	Thermal Conductivity (Btu/Ft/°F/h)	Cp (Btu/lb/°F)
Dowtherm G	150°C (305°F)	>554°C (>1030 °F)	14.0	-2°C to 371°C (28°F to 700°F)	1000	0.36	55.3	0.07	0.53
Dowtherm LF	127°C (260°F)	549°F (>1020°F)	27.0	-32°C to 316°C (-25 to 600)	12	0.21	51.3	0.059	0.58
Dowtherm J	63°C (145°F)	430°C (806°F)	137.8	-73°C to 302°C (-100 to 575°F)	1.4	0.11	36.1	0.063	0.69
Caloria HT-43	218°C (425°F)	385°C (725°F)	8.7	-1°C to 316°C (30 to 600°F)	400	0.47	41.1	0.049	0.69
Therminol 55	179°C (355°F)	357°C (675°F)	4.7	-4°C to 316°C (25 to 600 °F)	382	0.45	43.1	0.055	0.69
Therminol 60	292°C (310°F)	446°C (835°F)	11.1	-32°C to 316°C (-25 to 600 °F)	66 at -18°C (0°F)	0.37	48.8	0.004	0.63
Therminol 66	179°C (355°F)	374°C (705°F)	5.0	4°C to 343°C (40 to 650 °F)	264 at 10°C (50°F)	0.43	51.0	0.055	0.61
Dow Corning X2-1162	154°C (310°F)	392°C (738°F)	<14 at 670°F	-34°C to 399°C (-30 to 750°F)	27 at -18°C (0°F)	0.48	42.9	0.067	0.49
Mobiltherm 600	177°C (350°F)	366°C (690°F)	3.3	-1°C to 316°C (30 to 600°F)	2000	0.75	47.4	0.061	0.66

*None of the heat-transfer fluids listed cause serious health or pollution problems.
Cleveland open cup.
Autoignition can be catalyzed at lower temperatures by insulation/rust.

1 psia = 6894.8 Pa
1 Btu/ft/°FW = 1.731 w/m K

1 Btu/lb/°F = 4187 J/Kg. °K
1 lb/Ft^3 = 1 lb./Ft^3 = 16 oz kg/m^3

Table 3.14

Initial and Replacement Costs of Heat-Transfer Fluids

Heat-Transfer Fluid	Degradation Rates at 299°C (570°F) (percent/week)*	Cost per Gallon ($)	Total Initial Cost† ($)	Replacement Cost at 299°C (570°F) ($/yr)
Dowtherm G	0.0035	9.22	131,034	0
LF	0.218	7.90	112,274	14,400
J	0.145	5.63	80,013	7,200
Caloria HT-43	0.81	1.53	21,744	24,151¶
Therminol 55	0.81	3.01	42,778	47,501¶
60	0.031	8.91	126,628	1,682
66	0.061	9.76	138,709	6,707
Dow-Corning XL-1162	0.0029	19.31	274,434	17,060
Mobiltherm 600	0.81	1.62	23,023	25,572¶

1 U.S. Gallon = 3.785 liters

*Percentage degradation per 168 hours exposure as measured by gas chromatography extrapolated to (570°F) 299°C.

†The cost given is that for the unfired boiler concept without feedwater preheat. The costs associated with the heat-transfer fluids in the hybrid concept are 75 percent of this.

§3,600 hours exposure per year is assumed for a 15-year lifetime. It is assumed that replacement is required when 10-percent degradation into high-boiling components has occurred.

¶The viscosity of paraffin-based, heat-transfer fluids increases more rapidly with degradation than does the viscosity of the synthetic fluids. Replacement at lower percentage degradation may therefore be required. This estimate is thus likely to be low.

would appear to be a manufacturing problem that Sandia expects to have resolved by October 1980, operation with a receiver coating temperature as close to 288°C (550°F) as possible would be desirable to avoid any potential problems.

The receiver coating temperature is determined by the solar heat flux, heat losses, heat-transfer fluid temperature and flow rates, and the degree of fouling. For normal operation, with a heat-transfer fluid exit temperature of 299°C (570°F), the receiver coating temperature at the end at which the fluid exits will be ≈ 310°C (≈ 590°F). Should degradation of the heat-transfer fluid and fouling occur, the receiver coating temperature will rise to 321°C (610°F) and higher. As a result, it is imperative that even if stable receiver coatings are available, the heat-transfer fluid chosen does not suffer from rapid degradation to form polymeric materials that may foul the receiver tubes. The selection of a heat-transfer fluid has been addressed previously.

As a result of the lower water temperatures, no degradation of the black chrome receiver coating in the preheat block is anticipated in normal operation.

Degradation of Heat-Transfer Fluids - The heat-transfer fluid selected for use in a concept utilizing an unfired boiler will be one that will undergo negligible degradation in normal operation and will not foul the inside of the receiver tubes. However, if the collectors malfunction and expose the receiver tube to concentrated solar radiation in the absence of flow through the tube, the receiver temperature will rise causing both degradation of the receiver coating and fouling of its inside surface. This will seriously lower the efficiency of the collector and as such should be specifically guarded against in both design and operational procedures.

3.2.3. UNFIRED BOILER SYSTEM

3.2.3.1 Basic Concept

This system utilizes the unfired boiler concept described earlier for the hybrid unfired boiler/feedwater preheat system. A heat-transfer fluid carries the collected solar thermal energy from each of four blocks of solar collectors to unfired boilers. These are fed with boiler feedwater that is vaporized for injection into the wells. A simplified schematic for this system is shown in Figure 3.8.

3.2.3.2 Process and Instrumentation Description

This system is similar to the unfired boiler/feedwater preheat hybrid portrayed in Drawing 53857-1-50-1 (Appendix B). These systems differ however in that with the unfired boiler, all four blocks is furnished with a Dowtherm circulation pump, an expansion tank and a steam generator. Feedwater to the

Examining the fluids, we can eliminate Dow-Corning X2-1162 and Dowtherm J from further consideration. Dow-Corning X2-1162 is deleted as it undergoes rapid hydrolysis with water at temperatures above 177°C (350°F); in this system water leaks into the heat-transfer fluids are highly likely in the boiler. Dowtherm J is deleted on safety grounds; its flash point is low and its vapor pressure high.

Of the remaining fluids, Dowtherm LF and Therminol 60 can meet the performance criteria. The aliphatic and alkyl aromatic fluids, Caloria HT-43, Therminol 55, and Mobiltherm 600 offer low initial costs but are not pumpable at low temperatures and, at 299°C (570°F), their degradation rates are such that frequent replacement of the fluids might be required. The replacement cost of this (as calculated by net-present-value techniques) exceed the costs of using Therminol 60. Dowtherm G and Therminol 66 are subject to little degradation but require heating for start-up on cold days. Further examining the degradation properties of these fluids, we note that dynamic tests on Dowtherm G, a fluid that degrades to high-boiling compounds at 316°C (600°F) resulted in marked fouling. These results contrast to those obtained with Therminols 60 and 66. Fouling is also expected of Dowtherm LF, a fluid that degrades more rapidly than Therminol 60. In view of these factors, and the high viscosity of Therminol 66 at low temperatures, the appropriate choice of fluid would appear to be Therminol 60 or a blend of Therminol 60 with newly developed fluids such as Monsanto's MCS-2046. Such a blend would offer superior degradation properties.

We conclude that suitable heat-transfer fluids are available for service using unfired boilers for this project. The choice of fluid entails trade-off studies between the costs, performance and degradation rates of such fluids. Tentatively, it is recommended that Therminol 60 be selected as the heat-transfer fluid should an unfired boiler concept be adopted; this selection represents a change from the base-case concept where Dowtherm LF was used.

3.2.2.5 Problems With Hybrid Unfired Boiler/Feedwater Preheat System

Safety - The safety problems with the hybrid unfired boiler/feedwater preheat system are those associated with the presence of large volumes of heat-transfer fluids at temperatures above their flash-point and with the potential for exposing isolated lines filled with water or heat-transfer fluids to concentrated solar radiation. As such these problems are discussed in the evaluation of the other concepts.

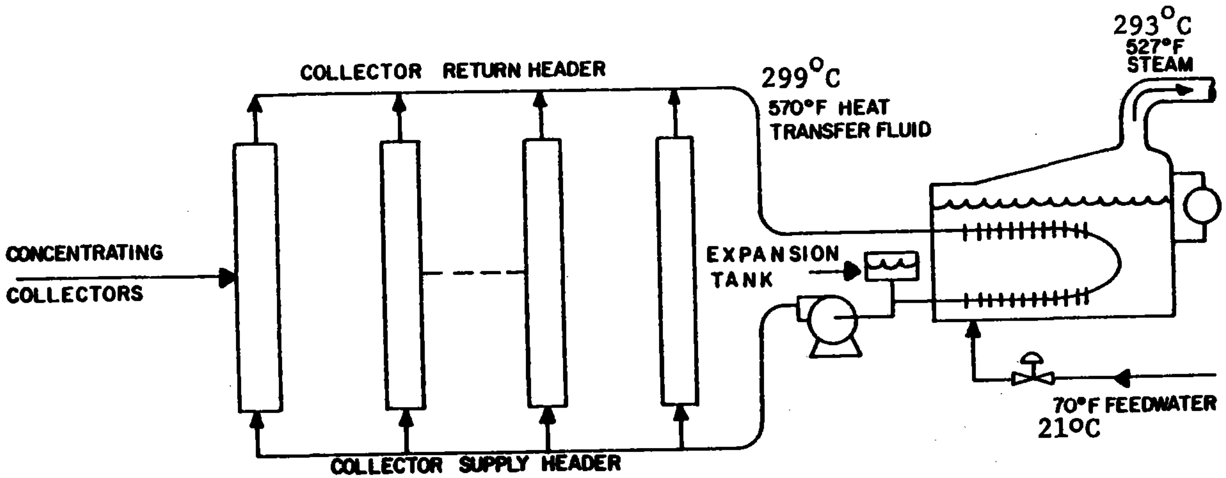
Black Chrome Receiver Coatings - As noted previously in our discussion of the flash-separator concept, the black chrome receiver coatings currently used frequently prove to be unstable at temperatures above 288°C (550°F). While this

Table 3.15

Unfired Boiler Concept - Operational Mode Status

Component	Operational Mode*			
	SG	CD	WU	FP
Heat-transfer fluid pump	On	On	On	On
Feedwater valves to unfired boilers	Liquid Level Control			
Boiler dump valves	Closed	Open	Closed	Open
Reclaim pumps	Off	On	Off	On
System controller	Active at all times			

*Modes: SG = Steam generation
CD = Cool-down
WU = Warm-up
FP = Freeze protection



Solar Unfired Boiler Concept

Figure 3.8

Freeze Protection Mode - A freeze protection mode of operation is initiated when ambient temperatures fall to a low value 2°C (35°F). This mode entails the circulation of feedwater through the feedwater lines and solar boilers and back to the fired boiler, preventing freezing in these lines. Column FP of Table 3.15 describes this mode of operation.

3.2.3.4 Preliminary Estimates of Capital, Operating, and Energy Costs

Preliminary estimates for the capital costs of the unfired boiler concept are presented in Table 3.16. Using these data and the assumptions detailed in Appendix B (Table B.2), the price of solar thermal energy delivered is estimated to be $34.86/10^9$J ($36.81/ 10^6 Btu). A breakdown of this price is presented in Table 3.17.

3.2.3.5 Problems With Unfired Boiler System

Safety - The problems in the unfired boiler concept are largely caused by the circulation of heat-transfer fluid through the distributed collector system at rates of .49 m^3/s (7800 gal/min) and at temperatures of 299°C (570°F). These temperatures are above the flash point of likely heat-transfer fluids, and thus ignition will occur in the event of a release should an ignition source be present or be created by static electricity. Furthermore autoignition of leaking heat-transfer fluid is possible if catalyzed by rust and/or insulation.

Autoignition may result in fires, additional failure in lines and hoses, and overheating and degradation of the heat transfer fluid. The problem of the autoignition of leaks of heat transfer fluids is particularly acute because of the pernicious nature of such fluids and the likelihood of failures in the insulated hoses.

Table 3.17 Unfired Boiler--Energy Costs

Solar thermal energy delivered	66 x 10^{12} J/yr	(63 x 10^9 Btu/yr)
Cost of solar thermal energy	$34.86/$10^9$J	($36.81/$10^6$ Btu)
Contributions to cost of solar thermal energ	$/$10^9$J	($/$10^6$ Btu)
Capital	26.55	(28.04)
Electric power	.52	(0.55)
Maintenance	6.82	(7.2)

Table 3.16

Unfired Boiler Concept--Estimates of Capital Costs

Component	Materials ($)	Subcontracts ($)	Direct Labor Man-Hours*	Direct Labor ($)†
Collectors	5,696,000		69,120	1,589,070
Dowtherm expansion tanks (3)	55,600			
Dowtherm storage tank (1)	18,100			
Steam generators (3)	160,000			
Circulation pumps (3)	44,000			
Reclaim pumps (3)	160,000			
Dowtherm change pump (1)	3,100			
Gravel		168,000		
Foundations		910,000		
Steel (allowance)	10,000		600	13,794
Building		40,000		
Piping	1,066,400		47,136	1,083,657
Instruments	309,600		40,150	923,048
Electrical	181,000		24,000	551,760
Insulation				
Pipe		620,900		
Equipment		58,000		
Painting		25,000		
Pick-Up truck and flexible hose	25,000			
Quadrant controls	40,000			
Testing	1,000		3,000	68,970
Field supervision, etc.	60,000		120	2,759
Dowtherm	112,000			
Subtotal	7,950,800	1,821,900	184,126	4,233,058
				1,821,900
				7,950,800
TOTAL (Materials, subcontracts, and direct labor)				14,005,800
Drafting, Procurement, etc.				712,000
TOTAL COST				14,717,800

*Assuming a productivity factor of 1.2.
†Assuming a wage rate of $10.45 per man-hour and a 120 percent overhead for indirect materials, tools, labor, supervision, and payroll burden.

To protect against fire hazards a series of steps will be taken. These include:

- o Installation of a ring main and water hydrants for fire protection purposes around the perimeter of the collector field
- o Use of closed-cell insulation to prevent the catalysis of autoignition
- o Adoption of other standard procedures in handling heat-transfer fluids (e.g., use of welded joints wherever possible, use of double mechanical seals on pumps, horizontal positioning of valves to avoid contamination of the insulation should leakage occur, etc.)
- o Installation of safety valves on the receiver, to prevent their rupture if heated when isolated.

It should be noted, however, that safety standards may require that all safety valves and vents discharge into a blowdown tank. The cost of such a system has not been included in the preliminary estimates.

Neither Dowtherm LF or any other potential heat-transfer fluid pose significant health hazards.

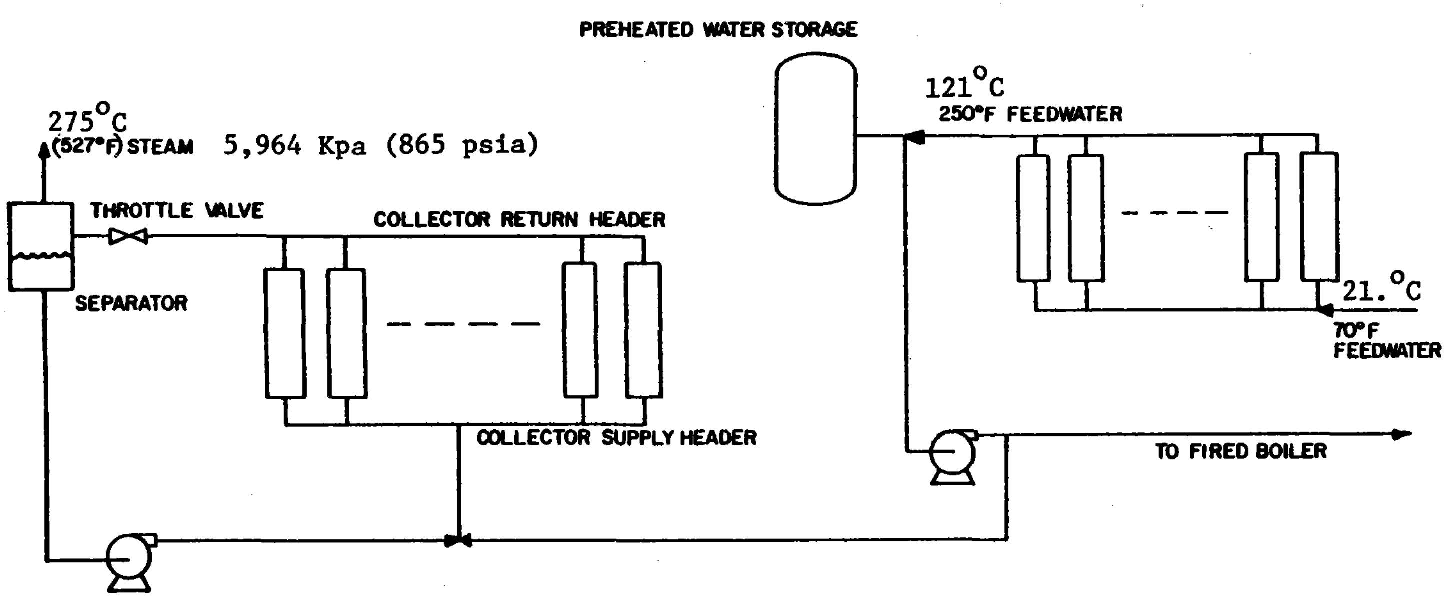
3.2.4 FLASH-SEPARATOR/FEEDWATER PREHEAT WITH STORAGE CONCEPT

3.2.4.1 Basic Concept

In this concept a large portion of the collector field is devoted to preheating feedwater for the solar and oil-fired steam generators. The remainder of the field serves to collect solar energy for steam generation using the flash-separator concept. Sufficient storage for preheated water is provided to maintain a supply of water to the fired boiler throughout the entire 24-hour day under conditions of peak insolation. Figure 3.9 is a simplified schematic of this system.

3.2.4.2 Process and Instrumentation Description

The proposed system is shown in Drawing 60035-1-50-2 (Appendix B). The collector field layout differs from that used in the evaluation of the other system concepts in that it is designed to meet the access requirements for the proposed new wells.



Flash-Separator/Feedwater Preheat With Storage Hybrid

Figure 3.9

The collector field is divided into two portions: 9594 m^2 (103,272 ft^2) are devoted to the preheating of boiler feedwater and 14022 m^2 (150,936 ft^2) to the generation of steam using the flash-separator concept. Under conditions of peak insolation, .0154 m^3/s (244.3 gal/min) of boiler feedwater are fed to the preheat field. This water is divided into three streams, each of which passes through six 24 m (80-ft) collector modules before exiting from the preheat field at 121°C (250°F). The preheated feedwater is then split into three streams; one goes to meet the immediate requirements of the fired steam generator, the second to provide the feedwater for solar steam generation and the third, comprising the remainder, goes to storage. The water flow rate through the preheat collector field is controlled to maintain a 121°C (250°F) water field exit temperature, provided the immediate requirements of the solar and fired steam generators are met. If insolation or collector availability are inadequate for that, however, the flow requirements of the steam generators are met and a lower water exit temperature is accepted.

The design of the pressurized water flash-separator system was described earlier. In the present hybrid concept, preheated boiler feedwater at 121°C (250°F) acts as make-up for the steam flashed; the feedwater is mixed with water emerging from the separator to provide a stream of water at 271°C (520°F) that enters the collector field and is heated to 282°C (540°F) before being flashed. At 282°C (540°F), 2.3 percent of the water is flashed to steam and the remainder is recirculated. The flow rate of water to the solar steam generator field is controlled by the water level in the separator.

To recover heat left in the system when steam can no longer be generated, provision is made for heat recovery. When the pressure in the separator falls to 5.61 kPa (815 lb/in2a), water is blown down from the separator to the inlet side of the boiler feedwater pump until the pressure in the separator falls to 448 kPa absolute (65 lb/in2a). Circulation of the water through the field and make-up with boiler feedwater that has passed through the preheat field continue until this time.

Following heat recovery, the storage tank provides the supply of feedwater to the fired steam generator. Finally, when the storage vessel has emptied, 21°C (70°F) feedwater is fed to the fired boiler after being preheated by water leaving the economizer section of the fired boiler; preheating is required so as to prevent condensation and acid corrosion in the economizer. The controls necessary for this are shown in the drawing. Other controls for the solar fields, water preheat and flash separator concepts have been described previously. Additional details of the equipment incorporated in this conceptual design are provided in Appendix B (Table B.1).

3.2.4.3 Operational Modes

This conceptual design allows for operation in five modes. In each of these it should be noted that the preheat field and solar steam generator field can be operated independently. These modes are:

Steam Generation Mode - The system is designed to generate 12,942 kg/h (28,538 lb/h) of 275°C (527°F) steam and preheat 55,459 kg/h (122,288 lb/h) of water to 121°C (250°F) under conditions of peak insolation. Of this preheated water, 14,172 kg/hr (31,250 lb/h) are used immediately in the fired boiler and 12,942 kg/h (28,538 lb/h) in the solar steam generator. The remaining 28,345 kg/h (62,500 lb/h) are fed to a storage vessel. As insolation declines, the flow of water to the solar steam generator and storage is reduced. The valve and pump status for this mode of operation are listed in column SG of Table 3.18.

Cool-Down Mode - When insolation is inadequate to produce sufficient 275°C (527°F) steam, a cool-down mode of operation is automatically initiated by the indication of a prolonged low feedwater flow to the steam generation system. In the cool-down mode, feedwater entering at 21°C (70°F) is circulated through the entire collector field before being blown down from the separator to the suction side of the boiler feedwater pump. This operation continues until the pressure in the separator falls to 448 kPa absolute (65 lb/in^{2}a). Then feedwater flow to the collector field will cease and the pumps will shut-off. This cool down mode of operation is summarized in Column CD of Table 3.18.

Warm-Up Mode - This mode of operation begins at sunrise. At that time a series of affirmative signals from control sensors will start up flow through the collectors and then cause the collectors to be removed from the stowed position so that solar energy collection will begin. Until steam is produced in the flash-separator system, no feedwater is fed to this system. Instead the preheated water is fed to the fired boiler and, if sufficient water at 121°C (250°F) is available, to storage.

Column WU of Table 3.18 summarizes the system status in the warm-up mode.

Freeze and Self-Protection Modes and Exceptions - These are as described for the flash-separator concept.

3.2.4.4 Preliminary Estimates of Capital, Operating, and Energy Costs

Preliminary estimates for the capital costs of the water preheat/overnight storage concept are presented in Table 3.19. Using these data and the

Table 3.18

Flash Separator/Feedwater Preheat With Storage Concept--
Operational Mode Status

Component	Operational Mode*			
	SG	CD	WU	FP
Preheat field:				
Feedwater pump	On	On	On	On
Feedwater control valve	Open	Open	Open	Open
	(On liquid level/temperature control)			
Steam generation field:				
Circulation pump	On	On	On	On
Feedwater control valve	On liquid level control			
Separator dump valve	Closed	Open	Closed	Open

*Modes: SG = Steam generation
CD = Cool-down
WU = Warm-up
FP = Freeze protection

Table 3.19

Flash Separator/Preheat With Storage Hybrid--
Estimates of Capital Costs

Component	Materials ($)	Subcontracts ($)	Direct Labor Man-Hours*	Direct Labor ($)†
Collectors	5,696,000		69,120	1,589,070
Flash separator drum	20,000		60	1,379
Circulation pump	41,000		240	5,518
Feedwater pumps (2)	54,600		276	6,345
Feedwater storage tanks (2)	90,000		120	2,759
Gravel		225,000		
Foundations		808,700		
Steel (allowance)	10,000		600	13,794
Building		40,000		
Piping	773,733		42,509	977,282
Instruments	330,000		35,976	827,088
Electrical	178,000		23,640	543,483
Insulation				
Pipe		664,712		
Equipment		68,800		
Painting		25,000		
Pick-up truck and flexible hose	25,000			
Quadrant controls	40,000			
Testing	700		2,940	67,591
Field supervision, etc.	72,000			
Subtotals	7,331,030	1,832,200	175,480	4,034,309
				1,832,200
				7,331,030
TOTAL (Materials, subcontracts, direct labor)				13,197,500
Drafting, procurement, etc.				619,000
TOTAL COST				13,816,500

*Assuming a productivity factor of 1.2.
†Assuming a wage rate of $10.45 per man-hour and a 120 percent overhead for indirect materials, tools, labor, supervision, and payroll burden.

assumptions detailed in Appendix B (Table B.2), the price of solar thermal energy delivered is estimated to be $30.90/$10^9$J ($32.63/10^6 BTU). A breakdown of this price is presented in Table 3.20.

Table 3.20 Flash Separator/Feedwater Preheat With Storage Hybrid--Energy Costs

Solar thermal energy delivered		71.7 x 10^{12} J/yr
Cost of solar thermal energy*	$30.90/$10^9$J	$32.63/$10^6$ Btu
Contributions to cost of solar thermal energy	$/$10^9$J	($/$10^6$ BTU)
Capital	23.28	(24.58)
Electric power	1.20	(1.27)
Maintenance	5.71	(6.03)

*A simple comparison of this price with the prices of solar thermal energy determined for the other concepts is invalid because of the different field layout and piping specifications.

3.2.4.5 Optimization of the Flash Separator/Feedwater Preheat With Storage Concept

This conceptual design is an extension of the pressurized water flash separator/feedwater preheat concept. Therefore no attempt will be made to rejustify the provision made for heat recovery, the freeze protection procedures, the selection of a 282°C (540°F) flash temperature and the pipe sizes selected. However, two alternatives to the base concept will be discussed. They are the provision of an increased field size devoted to preheating water, and the use of the storage vessel, not only as an overnight source of boiler feedwater, but also as buffer storage into which preheated feedwater is fed and from which boiler feedwater is supplied to the steam generators.

Increased Preheat Field Size - By increasing the size of the collector field devoted to preheating the boiler feedwater, the supply of solar preheated feedwater is more likely to be adequate even when some collectors are unavailable or when insolation is at less than peak values. This then enhances the solar contribution to thermal enhanced oil recovery. However, under conditions of peak insolation, a larger field cannot be fully utilized; this of course adversely affects the economics of the project. Finally it should be noted that the system will be slightly overdesigned and use can be made of this fact. For example, an increased volume of hot water can be stored on the chance that the system's availability or insolation may be less on the following day.

Alternatively, at the end of a day of high insolation, the temperature of feedwater leaving the preheat section can be allowed to increase slightly. Questions concerning the optimal size of the feedwater preheat collector field will be addressed at a later stage following a detailed analysis of system behavior during the course of the year if this concept were to be adopted.

Use of the Storage Tank to Provide Buffer Storage - The use of the storage tank to provide buffer storage between the collector preheat field and the solar and fired steam generators would partially uncouple the steam generators from the preheat collector field. The difference between this and the base-case design is in the method of control rather than in the piping layout. With this modification, the feedwater flow rate could be controlled so that preheated water emerged from the water preheat collector field at 121°C (250°F). This control would, however, be overridden when the liquid level in the storage tank fell to a low level. At that time, liquid level control would be exerted increasing the flow rate so as to maintain the storage tank liquid level. In the cool-down stage, the flow of water from the preheat field to the flash-separator field would bypass the storage vessel.

No detailed consideration was given to other feedwater preheat exit temperatures. A temperature of 121°C (250°F) was selected as this allowed for the most extensive operation of the collectors in a more efficient, low-temperature mode of operation without calling for substantial modifications to the fired steam generator.

Alternative Modes of Storage - Heat may be stored for preheating water in periods of low or no insolation as sensible or latent heat or in thermochemical storage.

In the base concept the storage mode adopted was to use pressurized water. This is a cheap material, with excellent heat capacity and transfer characteristics, that can be heated and used directly. Furthermore a 121°C (250°F) pressurized water storage does not require thick-walled steel pressure vessels. However, as water does not stratify well, themocline operation would be difficult.

Oil/rock thermal storage is another mode of storage that is well developed at this time - it is the reference thermal storage method for the Barstow and Shenandoah plants. It offers the advantages of operation at near ambient pressures and in a thermocline mode. This latter is a feature that is particularly useful if preheat is required at periods of low insolation early in the day. However, it entails the use of more expensive heat-transfer fluids, volumes of river rock or iron-ore pellets as inexpensive bulk materials and provision for heat exchangers. Furthermore the field pump and pipe sizes would be higher than those required when water is preheated directly. The capital costs of these items exceed those of the pressurized water concept.

Liquid metal and molten salt thermal storage systems are in less advanced stages of development. Among the operational problems that beset these concepts are the violent reaction of water with sodium if liquid sodium were to be used and the necessity of heat tracing all pipes to prevent solidification when the system is shut down. In addition, the stability of molten salts in prolonged operation has not been fully proven.

Latent heat thermal storage has not yet been demonstrated. There are three problems:

- A deterioration in the repeatability of the freeze-thaw cycle
- Poor heat-transfer properties at liquid-solid interfaces
- Poor thermal conductance of the solid phase that forms on the heat-transfer surface areas during heat extraction from storage.

The resolution of the heat transfer problems through such means as placing salts in thin trays will likely prove very costly.

Thermochemical storage in the temperature range to be used here is not yet at a suitable stage of development.

Collector Orientation - In all the base-case designs, the collectors were assumed to lie in a north-south direction. Reorientation of the collectors so that their axes of rotation lie in an east-west direction results in a 10-percent decline in annual energy collection. This decline is manifested by a reduction in the quantity of steam generated directly by solar energy. It is evident that a north-south collector orientation is preferable to an east-west orientation.

The question of collector orientation will be addressed in more detail elsewhere during the Solar Thermal Enhanced Oil Recovery project.

3.2.5 NATURAL CIRCULATION DIRECT STEAM GENERATION

A natural circulation direct steam generation system relies upon a density difference between water and steam/water mixtures for circulation. Circulation can be achieved in a solar thermal system by sloping the collectors and receiver tubes and mounting a steam drum high above the outlet of the tubes. In Figure 3.10, the elevation of a possible design is shown. A further requirement of the solar thermal system is that the receiver tubes be fixed in position. The use of flexible hoses (at present necessary tracking receivers) increases the pressure drop because of curvature. However, the assembly can be a hose designed to avoid downward fluid flow at the absorber outlet that might impede circulation and thus lead to overheating in the receiver tube. Furthermore, to ensure adequate circulation under conditions of insolation that are low but nevertheless sufficient to generate steam, the minimum slope of the receiver tube from inlet to outlet should be 0.5 radian (30 deg) upward with respect to the horizontal.

To keep piping sizes small and yet achieve good flow distribution, it will be necessary to install orifices. If valves are required in the downcomer and riser lines for control or isolation purposes, further elevation would be required to offset the additional pressure drop created. For this system, no additional treatment of the water would appear to be necessary.

3.2.5.1 Advantages and Disadvantages of Natural Circulation Direct Steam Generation

This concept offers several advantages. They are:

- The operating temperature 275°C (527°F) is lower than any other steam generation concept for this project. This gives this concept a lower likelihood of degradation of the black chrome receiver coatings. In addition the heat losses will be lower.

- The operating pressures are less than those in the flash-separator concept and, through the use of a fixed receiver and the avoidance of flexible hoses, the likelihood of premature failure of components and steam leakage are lessened.

- As the receiver tubes are sloped at 0.5 radian (30 deg) to the horizontal, cosine losses are diminished and the solar thermal energy delivered increases.

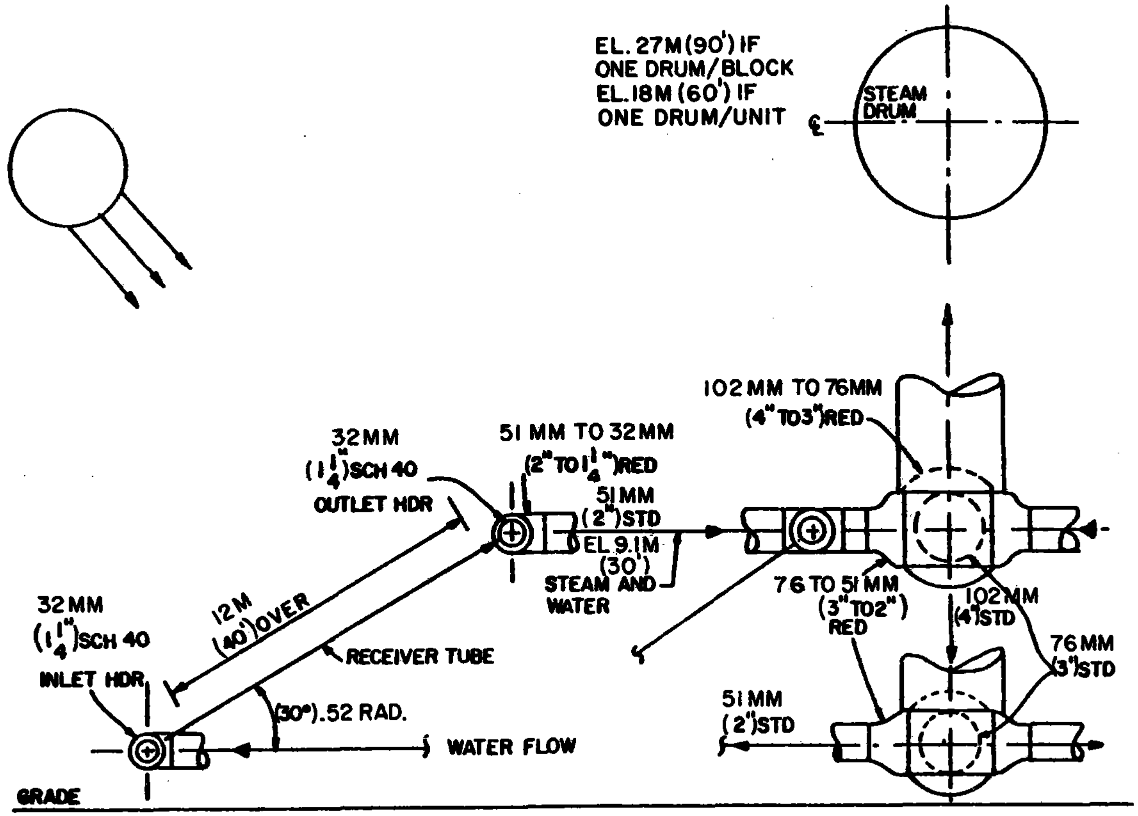
- No parasitic power is consumed except in freeze protection.

- The absence of a pump allows for increased reliability.

However, the disadvantages of this concept are such that the cost and technological risk are excessive for use in this project. These disadvantages are:

- The technology is untried. Should circulation be inadequate, fouling, corrosion and overheating of the receiver tubes, and degradation of their coating will result.

- The cost of the support structure to hold the outlet end of the collectors and the steam drum over 6 m (20 ft) off the ground will be high.



Elevation of Natural Circulation Direct Steam Generation System

Figure 3.10

- The requirement for fixed receiver collectors of sufficient aperture is unlikely to be met economically by 1981. Current fixed receiver collectors are of both lower efficiency than parabolic trough collectors with tracking receivers and of so small an aperature that it would be difficult to ensure adequate water circulation through the receiver tubes.

Some of these disadvantages can be eliminated by introducing a circulating pump to achieve direct steam generation with forced circulation. This would eliminate circulation problems and enable a level system to be used, thereby reducing support structure costs. However, as the technology cannot be considered to be state of the art, estimates have not been prepared for this natural circulation, direct boiling concept and it will not be considered further. However, we believe that it would warrant additional consideration on naturally sloping sites.

3.3 Conclusions From Study of Alternate Systems

Designs for the use of solar thermal energy in thermal enhanced oil recovery operations at the Edison field are profoundly influenced by two factors:

- The collection of solar thermal energy decreases in efficiency as the temperature of the solar receiver is raised (Figure 3.3).
- As the rise in fluid temperature allowed across the solar collector field is decreased, the flow rate must increase.

These statements are reflected in the following observations:

- It is advantageous to devote as large a portion of the solar collector field as possible to the preheating of boiler feedwater. This is clearly demonstrated in the comparison of the unfired boiler and unfired boiler/ feedwater preheat concepts (Table 3.21). Not only is the efficiency of collection increased but also the capital costs and parasitic and thermal energy losses decreased in the feedwater preheat/ unfired boiler hybrid as a result of the lower flow rates and smaller pipe sizes in the preheat field. Furthermore, the diurnal variation in the steam injection rate is lessened as less steam is generated directly by solar energy.

- Flow rates and thus pipe sizes and costs and pumping costs are high in a system devoted to steam generation at Exxon's Edison field. This results from the necessity of operating the system within temperature bounds imposed by the requirement that 275°C (527°F) steam be generated and by the wish to avoid solar receiver temperatures in excess of 288°C (550°F) that would degrade the receiver coatings.

From these observations it can be concluded that the optimal system design will devote the largest possible portion of the solar collector field to preheating boiler feedwater. Therefore, we recommend that solar energy be used to preheat feedwater for the fired boiler and that overnight storage for this feedwater be provided. However, in itself, this mode of operation is inadequate to meet the requirements made of the design. Not only does it run counter to the initial intent of the study to examine solar steam generation for thermal enhanced oil recovery but with this mode of operation, it would only be possible to supply the (20,520 MWh/Yr (70 x 10^9 BTU/Yr) required of the solar thermal system if the feedwater were preheated to approximately 260°C (500°F) rather than to the 121°C (250°F) we have considered. This would not only reintroduce the potential hazards inherent to the operation of the system at high temperatures and pressures but would also require more expensive vessels for overnight storage, replacement of the existing feedwater pump, and modification of the fired steam generator if its efficiency is not to be reduced. These modifications and their consequences lie outside the scope of

Table 3.21

Comparison of Conceptual Designs

Concept	Capital Cost ($)	Solar Thermal Energy Delivered		Cost of Energy	
		10^{12} J/yr	(10^9 Btu/yr)	$/$10^9$ J	($/$10^6$ Btu)
Flash separator	12,894,600	67.9	(64.4)	31.29	(33.01)
Flash separator/ feedwater preheat with storage hybrid*	13,886,500	71.7	(68.0)	30.93	(32.63)
Unfired boiler	14,717,800	66.8	(63.3)	34.89	(36.81)
Unfired boiler/ feedwater preheat hybrid	14,030,000	70.7	(67.0)	31.66	(33.40)

*Capital costs for this concept were estimated using a different collector field layout.

this study. Accordingly, a hybrid system providing for both steam generation and preheating of feedwater for the fired and solar steam generators appear to represent the best design. Our next task is thus to select a system for steam generation.

Two approaches to steam generation have been evaluated in this study: the flash separator concept and the unfired boiler concept. Of the two, the latter has greater capital cost, operates at higher temperatures (thus making the degradation of receiver coatings more likely), uses a flammable heat-transfer fluid whose degradation may lead to fouling, and delivers costlier solar energy. On the other hand the flash-separator concept expends more parasitic power and operates at high pressures that may detract from the reliability of the flexible hoses that connect the receiver tubes to the distribution piping. On balance, we believe the flash-separator concept represents the best approach for steam generation if adequate flexible hoses can be provided. Accordingly, we recommend a hybrid flash-separator/feedwater preheat with storage concept for use in this project.

The concepts we have evaluated have been prepared specifically for use in Exxon's Edison field. This field differs from others where thermal enhanced oil recovery operations are viable in that the steam pressure required is higher; 5510 kPa absolute (800 lb/in^2a) steam is necessary rather than 2070 kPa absolute (300 lb/in^2a) steam pressure commonly employed in other fields. It would therefore be appropriate to briefly discuss operations that require designs for lower steam pressures.

The generation of steam at lower pressures will allow the system to be operated at lower temperatures and/or with lower flow rates. With lower receiver temperatures, the efficiency of collection will increase; with the lower flow rates, introduced by operating with increased temperature differentials, piping, and insulation costs and parasitic and thermal energy, losses are reduced (Table 3.4). These changes in the mode of operation will reduce the cost of generating steam and allow more steam to be generated in the winter months or whenever insolation is low. In addition, operation at lower temperatures will reduce the safety and reliability problems associated with the circulation of pressurized water and heat-transfer fluids and allow the use of alternatives to flexible hoses between the receiver tubes and the distribution piping.

A final conclusion that can be drawn from this study is that maintenance costs for solar thermal enhanced oil recovery systems may represent a substantial portion of the total cost of delivered solar thermal energy. This point must be stressed in the design, procurement, and construction phases in order to ensure that wherever possible maintenance problems are avoided and costs reduced.

4. TRADE-OFF STUDIES

Following the evaluation of a series of conceptual designs, a flash-separator/feedwater-preheat-with-storage system concept was selected as appropriate for preliminary design of a solar thermal system to be used in enhanced-oil-recovery operations at Exxon's Edison, California, field. Trade-off studies were then performed to help optimize this chosen concept. These studies are divided into two categories: those comparing commercially available solar collectors and those evaluating other aspects of system design, such as collector spacing. Additional trade-off studies have also been performed to extend the applicability of this study to other oil fields and layouts.

4.1 Collector Trade-Off Studies

In these studies, the performance and characteristics of various commercially available line-focusing concentrating collectors were determined. In addition, the Sandia Engineering Prototype Trough (EPT) collector characteristics were studied. A collector with the physical characteristics of the Sandia EPT collector but with a performance more typical of the less efficient commercially available collectors was used for analysis and preliminary design. The following commercial collectors were considered:

- Acurex
- E-Systems
- Jacobs-Del
- Solar Kinetics
- Suntec Systems.

In accordance with DOE guidelines, central receiver, dish, and flat-plate solar collectors were not considered.

Because the steam-injection pressures required at the Edison field dictate steam generation at 275°C (527°F), any solar collector chosen for the steam-generation collector field must be capable of efficient operation in a temperature range of 260°C (500°F) to 315°C (600°F). In the preheat field, collectors operate at temperatures between 21°C (70°F) and 121°C (250°F).

Because of changing state-of-the art in line-concentrator development, no attempt has been made to select a specific collector. However, the advantages and disadvantages of the various collectors examined are stressed.

4.1.1 CONCLUSIONS

The Sandia EPT collector was selected for use in analysis and preliminary design so as not to discourage manufacturers not chosen at this stage. However, it is not expected that this collector would be specified and bid in the procurement phase; rather, an existing commercially available collector would be selected and purchased.

Table 4.1 summarizes the characteristics that describe the Sandia EPT collector used in the analysis and preliminary design. A 24 m (80-ft) long collector comprised of four 6 m (20-ft) mirror modules is assumed. The collector efficiency curve used in the analysis is shown in Figure 4.1. This curve follows the shape of the Sandia EPT curve, but has an intercept more representative of existing collectors. Sandia has collected peak efficiency data (near noon) over the range of 0 to 1.14°C/w/m^2 (0 to 2.0°F/Btu/h/ft^2) and the applied curve fits that data. The curves shown beyond 0 to 1.14°C/w/m^2 (2.0°F/Btu/h/ft^2) are extensions of the curve which fit that limited data.

The Sandia EPT collector is compared with existing manufactured collectors in Table 4.2. To provide 23,226 m^2 (250,000 ft^2) of mirror aperture, 504 EPT collectors comprised of 2016 mirror modules are required. In comparison, E-Systems and Jacobs Del collectors are so small that they would require 10,920 and 16,386 mirror modules ganged into 1092 and 682 collectors respectively, to provide the same sized collector field.

Table 4.1

SANDIA EPT CHARACTERISTICS

Description	Parabolic Trough	
Aperture size	2m	(6.5 ft)
Collector length (Multiples x module size)	24.4m (1.2m x 6.1m)	(80 ft (4x 20 ft)
Gross area	48.3 m^2	(520 ft^2)
Focal length	482.85mm	19.01 in.
Mirror material		Back-silvered glass
Drive mechanism		Motor/gearbox drive
Tracker type		Flux-line tracker or shadow bar
Absorber size (O.D.)	31.75mm.	1-1/4 in.

Table 4.1

Sandia EPT Characteristics continued

Description	Parabolic Trough
Absorber material	Steel
Absorber coating	Black chrome
Absorber envelope	Pyrex glass tube
Temperature limit	371°C (700°F)
Piping interface	Flex hoses

The Sandia EPT offers a good representation of the other three collectors. All consist of moving mirrors and moving receivers. All have high concentration ratios. The length of absorber required is similar in each case. However, when compared with the Sandia EPT, an Acurex field would require 8 percent more in drives and trackers, whereas a Suntec field would need 26-percent fewer and a Solar Kinetics field 7 percent fewer.

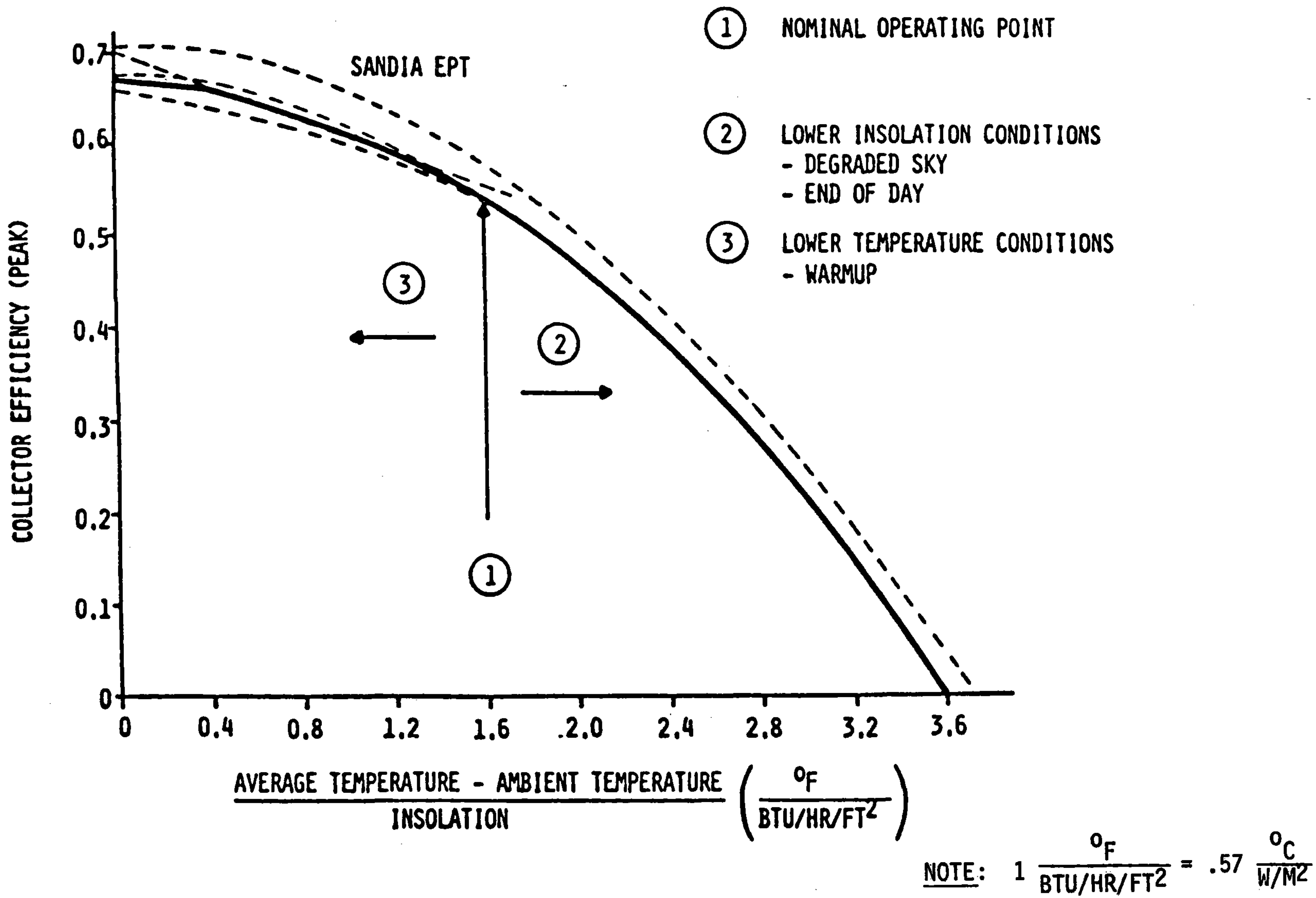
4.1.2 DETAILS

4.1.2.1 Collector Characteristics And Performance

Line-focusing concentrating collectors can be provided in a variety of ways, including:

- Moving mirror, moving receiver
- Fixed receiver, moving mirror
- Fixed mirror, moving receiver
- Linear heliostat
- Fresnel lens.

Of these options, the moving parabolic trough mirror with attached (and moving) receiver has shown the greatest potential in tests and demonstrations. The other concepts are experiencing difficulty in moving beyond the R&D stage.



Generic Collector Efficiency

Figure 4.1

Table 4.2

Impact of Selection (To provide 23,226 m^2 (250,000 ft^2) of collector area)

	E-Systems	Jacobs-Del	Acurex	Sandia EPT	Suntec	Solar Kinetics
Collector modules	10,920	16,386	4,368	2,016	1,496	1,872
Module size (ft) (aperture x length)	3 x 8	2 x 8	6 x 10	6.5 x 20	9 x 20	7.04 x 20
Organization	10 ganged 10W x 1L	24 ganged 6W x 4L	8 modules	4 Modules	4 modules	4 modules
Collectors	1,092	682	546	504	374	468
Drives	1,092	682	546	504	374	468
Trackers	1,092	682	546	504	374	468
Absorber length (ft)	87,360	130,944	43,680	40,320	29,952	37,440
Savings (Percent)	-117	-35	-8	0 (Base)	26	7

1 Ft = .3048 m

1 Ft^2 = .0929 m^2

Table 4.3
Collector Characteristics

Characteristics	Acurex	Jacobs-Del	Solar Kinetics	Suntec	E-Systems
Model number	3001		T-700	SH-1655	
Description	Parabolic trough	Parabolic trough, fixed receiver	Parabolic trough	Parabolic trough	Fresnel lens
Aperture size	6 ft	2 ft (6 ganged - 12 ft)	7.04 ft	9 ft	3 ft (10 ganged - 30 ft)
Collector length (Multiples x module size)	80 ft (8 x 10 ft)	32 ft (4 x 8 ft)	120 ft (6 x 20 ft)	80 ft 4 x 20 ft)	8 ft
Gross area	480 ft^2	384 ft^2	840 ft^2	700 ft^2	240 ft^2
Rim angle	90°	110°	80°	72°	45°
Focal length	18 in.	---	22.2 in.	36 in.	18 in.
Mirror support structure	Steel	Steel weldment	Aluminum sheet monocoque on aluminum bulkheads	Aluminum honeycomb	
Mirror material	Aluminum sheet	Glass, back silvered	Aluminum acrylic (FEK-244)	Aluminum acrylic (FEK-244) on glass	Curbed fresnel lens (Acrylic)
Drive mechanism	115VAC gear motor with speed reducer and protection clutch	24VDC drive of ganged units via shaft and worm	Hydraulic	24VDC drive of gearbox and chain	Motor-driven cable gang drive
Tracker type	Shadow band	Shadow bar or flux line tracker	Shadow bar or other	Shadow bar or flux line tracker	Shadow bar?
Absorber size (O.D.)	1.25 in.	0.5 in.	1-5/8 in.	1-5/8 in.	1.5 in.
Absorber material	Steel	Steel	Steel	Steel	Steel
Absorber coating	Black chrome over nickel	Black chrome over dull nickel	Black chrome over nickel	Black chrome over nickel	Black chrome
Absorber envelope	Pyrex glass tube	Pyrex glass tube	Pyrex glass tube	Glass window, insulated back	Lens front, insulated back
Absorber plug	Twisted tape (Optical)	---	Ribbon turbulence inducer	Annulor plug	---
Fluid	Water or organic fluid	---	Heat transfer oil or water	Water or oils	---
Flow rate	2 to 15 GPM	---	3 GPM minimum	Tested at 3 to 7.5 GPM	---
Temperature limit	316°C (600°F)	316°C (600°F)	343°C (650°F)	316°C (600°F)	260°C (500°F)
Piping interface	Flex hose	Fixed receiver	Flex hose	Flex hose	Fixed within array, undefined at manifold

NOTE:
1 Ft=.3048 m
1 Ft^2=.0929 m^2
1In=25.4mm
57.296°=1 radian
1.585 x 10^4 gal/min=1 m^3/Sec

Table 4.3 is a comparative tabulation of collector characteristics for the five selected collector designs. Although other potential concentrating collector designs exist, these five were felt to be the most likely candidates. The small Jacobs-Del and E-Systems modules are considered to be ganged into collector units of a size comparable to the other collectors. Collector advantages and disadvantages are discussed in the subsections below.

Figure 4.2 compiles collector efficiency curves from the manufacturers brochures and published Sandia data. The grouping of the latest and best collectors (SKI-700, Suntec-Hexcel) at the top, and the older collectors below is obvious. Figure 4.3 is an abridged tracing of Sandia test data, showing the collectors of interest to the STEOR program. It should be noted that the Suntec collector is essentially the Hexcel design. A Suntec collector is now being tested at Sandia.

In Tables 4.4 and 4.5, economic analyses and the results of the simulation of solar-thermal-system performance using Acurex, Solar Kinetics and Suntec collectors are presented. It will be noted that with the complete Acurex collector field, less solar thermal energy is delivered as steam and more as preheated water. The latter is a consequence of the larger portion of the Acurex collector field being devoted to preheating water, the former results from the lower efficiency of the Acurex collector and the consequent reductions in the duration and rate of steam generation. Assuming that total costs of collectors and fittings are identical, the Solar Kinetics and Suntec collectors are essentially equivalent in performance to the Sandia EPT collector, while the Acurex collector with polished aluminum mirrors is less effictive. The selection of Acurex collectors could be justified if FEK-244 mirrors were to be used and the collector was determined to offer reliability and maintenance cost advantages. The Jacobs-Del and E-Systems collectors were not simulated because their performance is poor in the temperature range required for steam generation at the Edison field and because their size requires more drive units and controllers, hence giving them a propensity for greater costs and reliability and maintenance problems. System performance was simulated using a Honeywell system model and Fresno TMY weather data.

4.1.2.2 Collector Descriptions

Acurex. The Acurex line-focusing concentrating collector combines a moving parabolic mirror with a moving receiver that together track the sun to collect the concentrated energy. The mirror module is fabricated of sheet metal affixed to a steel tubular torque tube. An offset axis of rotation provides mass balancing, at the expense of some off-noon mirror shading by the bearing. The mirror is made of polished aluminum sheet. The absorber tube is selectively coated with black chrome and is enclosed in a Pyrex glass jacket to reduce heat losses.

Table 4.4

Comparison of Collectors

Description	Sandia EPT	Suntec	Solar Kinetics	Acurex
Collector spacing (ft)	12.5	17.5	13.5	12.0
No. preheat collectors	144	106	138	88
Preheat (ft^2)	72,187	72,765	70,886	82,513
No. steamer collectors	360	252	342	380
Steam (ft^2)	175,468	169,785	175,674	166,782
Total field area (ft^2)	245,655	242,550	246,560	248,245
Performance *(10^3 Btu/ft^2 yr)				
Direct normal insolation	719	719	719	719
Incident	626	626	626	626
Energy available	578	578	578	580
Energy collected	304	305	300	280
Total energy delivered	272	274	270	237
Solar steam delivered	215	221	231	168
Solar preheat delivered	412	397	368	377
Losses	33	30	29	37

*The performance of the collectors was simulated using Honeywell, Inc.'s Sunsim program and Fresno Typical Meterological Year weather data.

1 Ft = .3048 m

1 Ft^2 = .0929 m^2

10^3 Btu/ft^2 = 1.136 J/m^2

Table 4.5

Comparison of Collectors--Complete Field Performance

Description	Sandia EPT	Suntec	Solar Kinetics	Acurex
Collector spacing (ft)	12.5	17.5	13.5	12.0
Performance (10^9 Btu/yr)				
Direct normal insolation	176.5	174.3	177.2	179.1
Incident	153.8	151.9	154.4	158.0
Energy available	141.9	130.6	142.6	144.6
Energy collected	74.8	74.0	74.0	69.8
Total energy delivered	66.7	66.5	66.7	59.1
Solar steam delivered	37.8	37.6	40.6	28.0
Solar preheat delivered	28.9	28.9	26.1	31.1
Header loss to atmosphere	4.8	4.5	3.7	4.8
Storage loss to atmosphere	0.7	0.7	0.6	0.7
Overnight losses	2.6	2.2	2.9	3.7
Storage requirement (lb)	490,000 (W)	575,000 (W)	500,000 (W)	3,000,000 (S)
Cost of energy delivered ($/$10^6$ Btu)	32.79	32.88	32.79	37.64

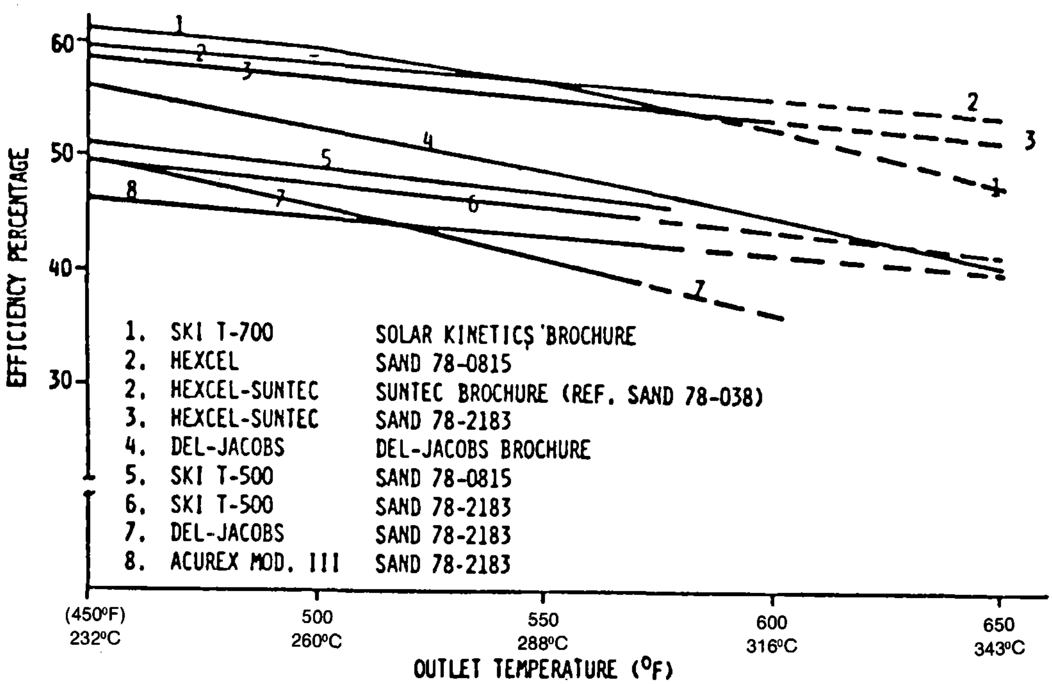
(W) - Maximum storage required in winter
(S) - Maximum storage required in summer

1 ft = .3048 m

10^9 Btu/yr = 1.055 x 10^{12} J/yr

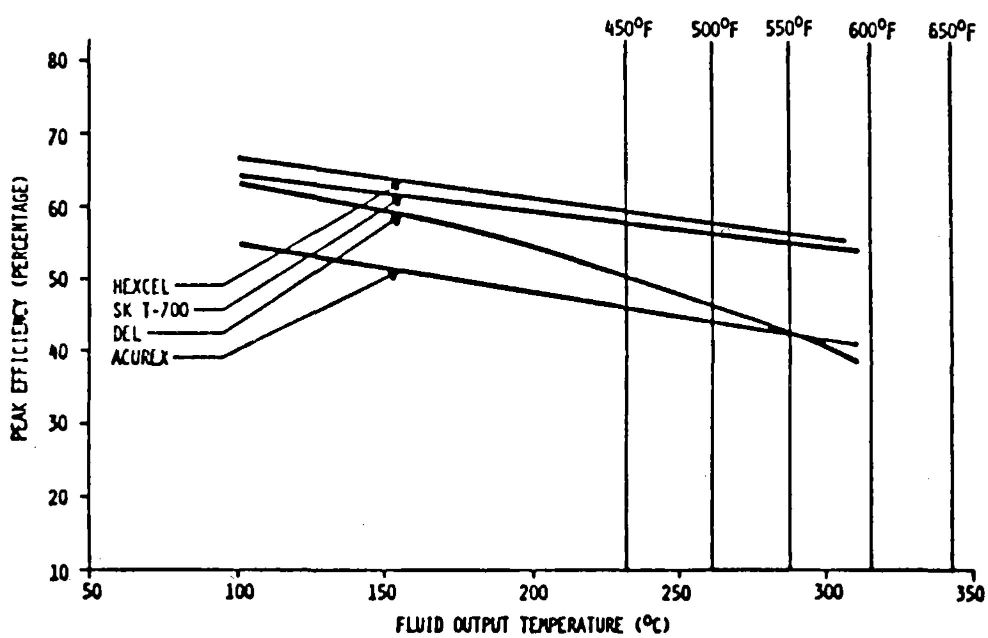
1 lb. = .454 kg

$/$10^6$ Btu = ($/1.055 x 10^9J)



Collector Efficiencies (Published data)

Figure 4.2



Collector Efficiencies (Sandia data)

Figure 4.3

The Acurex collector typically interfaces with the field headers with flexible hose.

Collector drive is via an ac electric motor, chain, gearbox, and an exposed worm and bull wheel. The bull wheel has a segment removed to mechanically eliminate damaging overtravel. A new, improved shadow-band tracker (of Acurex design and manufacture) is included with the collector.

Acurex has manufactured over 7,618 m^2 (82,000 ft^2) of concentrating collectors--4,459 m^2 (48,000 ft^2) installed and 3,158 m^2 (34,000 ft^2) operating. Other large collector fields (both thermal and photovoltaic) are being designed and proposed.

Characteristics of the Acurex collector are presented below:

- Advantages:
  - Viable manufacturer
  - Meets STEOR temperature requirements
  - Has collector size consistent with Sandia EPT
  - Has small mirror, thus smaller support structure
  - Has second-generation field currently in start-up phase
  - Is experienced with polished aluminum, glass, and FEK-224 mirrors.
- Disadvantages:
  - Offers poor collector efficiency (mirror)
  - Has small mirror, thus requires more drive units and more controllers
  - Has a receiver envelope that is very difficult to clean and replace

- Has a very slow rotation rate, resulting in long stow and unstow times

- Requires a back-up generator to stow the collectors in the event of a power failure in the high-temperature steam-generation field.

o Potential problems:

  - Receiver envelope breakage has been significant

  - Tracking problems have been frequent

  - Low efficiency of receiver may strongly impact performance at STEOR conditions

  - Power interruption between electrical substation/generator and collector motor will prevent automatic stowing of collectors.

o Maintenance considerations:

  - Receiver envelope is difficult to remove and/or clean

  - Chain drive requires care

  - Steel construction requires painting.

o Environment and weather deterioration:

  - Steel construction requires painting

  - Dust inside receiver glass reduces performance

  - Polished aluminum mirrors slowly degrade.

o Installation parameters:

  - The 3 m (10-ft) mirror modules and small aperture result in many small support posts and footings

  - Mirror shape is defined; receiver position is adjustable.

E-Systems. The E-Systems line-focusing concentrating collectors are comprised of a long Fresnel lens assembled into an insulated receiver enclosing the absorber tube at the lens focus. The complete unit rotates to track the sun. The structure is a sheet-metal channel. The absorber tube is flattened into an oval shape to increase its width and is selectively coated with black chrome.

This E-Systems collector typically interfaces with the field headers with swivel joints. Collector drive is with an electric motor and cables and pulleys ganging numerous collectors together. Tracking control is via a shadow band device.

E-Systems has only a few collectors installed. Characteristics of the E-Systems collector are presented below:

- Advantages:
  - High efficiency is claimed
  - Has Fresnel lens that provides focusing and glazing
- Disadvantages:
  - Has no field experience
  - Has small aperture, thus requires more drive units and more controllers.
- Potential problems:
  - Collector efficiency
  - Tracking accuracy of ganged units
  - Off-axis effects on Fresnel lens focus
  - Absorber expansion at STEOR temperatures
  - System reliability because of large number of collectors.
- Maintenance considerations:
  - Sheet-metal structure requires painting
  - Gang drive may require regular adjustments.

- o <u>Environmental and weather deterioration</u>:
  - Sheet-metal structure requires painting
  - Lens life is unknown.

<u>Jacobs-Del</u>. Jacobs-Del line focusing concentrating collector uses a moving parabolic mirror that tracks the sun and rotates around a fixed, stationary receiver. The mirror module consists of back-silvered glass segments held in a metal frame. The mirror modules are small (0.6 m aperture by 2 m length) (2 ft aperture by 8-ft length) and mass-balanced. Mirror segments are approximately 0.2 m x 0.6 m (8 in. x 2 ft), making them easy to handle, assemble, and replace. The absorber tube is selectively coated with black chrome and is enclosed in a Pyrex glass jacket to reduce heat losses.

Since the receiver is stationary, even when tracking the sun, no swivel joints or flexible hoses are required at the interface with the headers. Collector drive is via electric motor, gearbox, and drive shafts, with worm and gear interface at each collector module. Collectors can rotate 6.3 rad (360 deg) without damage. Numerous mirror modules are typically ganged together with drive shafts off a common motor drive and controller. Because of the very small aperture of the mirror, wind loads are very low and thus drive components are small. Tracking has typically been controlled by a shadow-bar tracker. A flux line tracker has been successfully employed on the collector in a test-bed environment.

Jacobs-Del has less than 464 m^2 (5000 ft^2) of collectors installed. Characteristics of the Jacobs-Del collector are presented below:

- o <u>Advantages</u>:
  - Is small in size
  - Has glass mirror
  - Has fixed receiver.
- o <u>Disadvantages</u>:
  - Performs poorly at STEOR temperatures
  - Has limited field experience
  - Has small mirror, thus requires more drive units and controllers.

- Potential problems:
  - Absorber expands at STEOR temperatures
  - Receiver envelope may accumulate dust
  - Low efficiency of receiver would strongly impact performance at STEOR conditions
  - Exposed worm drive is unproven.
  - Accuracy of ganged drive is questionable.
- Maintenance considerations:
  - Receiver envelope may be difficult to remove and clean
  - Glass mirrors are easy to clean
  - Steel construction requires painting
  - Gang drive may require regular adjustments.
- Environment and weather deterioration:
  - Steel construction requires painting
  - Dust inside receiver glass reduces performance.
- Installation parameters:
  - Components are small and easy to handle in assembly
  - Small-sized units require many small support posts and footing.
  - Receiver position is defined; mirror segment adjustment is tedious.

Solar Kinetics. The Solar Kinetics line-focusing concentrating collector combines a moving parabolic mirror, tracking the sun, with a moving receiver (fixed to the mirror) to collect the concentrated energy. The mirror module is fabricated of aluminum sheets on forged aluminum ribs forming a monocoque structure. The ribs define the parabolic shape of the aluminum sheet and are connected along a torque tube. Concrete counterweights behind the mirrors provide mass-balancing at the expense of additional weight. The mirror is made of FEK-244, an aluminized acrylic adhesively bonded to the aluminum structure. The absorber tube is selectively coated with black chrome and is enclosed in a Pyrex glass jacket to reduce heat losses.

The Solar Kinetics collector typically interfaces with the field headers with a flexible hose. Collector drive is via a hydraulic ram and a chain and sprocket. Hydraulic fluid is piped from a central located hydraulic pump and accumulator located at each collector row. The hydraulic drive has valves that allow both a very slow speed for tracking and a high speed for stowing and unstowing. The hydraulic ram travel is limited to prevent damage caused by collector overtravel. The hydraulic accumulator provides stow energy if electric power fails. Tracking has typically been controlled by a shadow-bar tracker. A flux-line tracker has been successfully utilized on the collector in a test-bed environment.

Solar Kinetics have manufactured and installed about 650 m^2 (7,000 ft^2) of thermal concentrating collectors and about 3,530 m^2 (38,000 ft^2) of photovoltaic concentrating collectors. Other large collector fields (both thermal and photovoltaic) are being designed and proposed. Characteristics of the Solar Kinetics collector are presented below:

- Advantages:
  - Is viable manufacturer
  - Meets STEOR temperature requirements
  - Has collector aperture similar to Sandia EPT
  - Offers good collector efficiency
  - Has hydraulic drive and drive rates
  - Uses mirror material that can be patched.
- Disadvantages:
  - Its operating experience is limited.
  - Receiver envelope is difficult to clean and replace.
  - Subassemblies shipped to site are large and bulky.
- Potential problems:
  - FEK-244 durability.
  - Receiver envelope breakage has been significant.
  - Tracking problems have been frequent.

- o Maintenance considerations:
  - Very little steel needs painting.
  - Hydraulic fluid leaks require repair.
  - Receiver envelope is difficult to remove and/or clean.
  - FEK-244 requires gentle cleaning.
- o Environmental and weather deterioration:
  - FEK-244 has shown deterioration from environment and weather.
  - FEK-244 is easily damaged by bumping, rubbing, or heating
  - Dust inside receiver glass reduces performance.
- o Installation Parameters:
  - Subassemblies are fabricated in factory and shipped to site for final assembly.
  - Some subassemblies are large and bulky.
  - Counterweights are heavy.
  - Mirror shape is defined; receiver position is adjustable.

Suntec Systems. The Suntec Systems line-focusing concentrating collector combines a moving parabolic mirror, tracking the sun, with a moving receiver (fixed to the mirror) to collect the concentrated energy. The mirror module is fabricated of aluminum honeycomb affixed to a steel torque tube. Concrete counterweights behind the mirror provide mass balancing at the expense of additional weight. The mirror is made of FEK-244. The absorber tube is selectively coated with black chrome and is enclosed in a Pyrex glass jacket to reduce heat losses.

Because the Suntec collector is a design conceived, developed, and first manufactured by Hexcel, Incorporated, this description covers experiences and characteristics of both manufacturers. The current Suntec model exhibits minor improvements over the collectors manufactured and installed by Hexcel.

The Suntec collector typically interfaces with the field headers with a flexible hose. However, in some low-temperature 250°C (below 121°F) applications swivel joints are used.

Collector drive is typically via a dc motor, chain, and gearbox; however, versions with ac drive motors have been manufactured and installed. The dc drive version takes 24 v of power from a battery pack that provides power to stow the collectors in the event of ac power loss. A trickle charger keeps the batteries charged and spreads the electric load smoothly over the entire day. Originally the Suntec and Hexcel collectors were controlled by a shadow-bar tracker. Later installations use flux-line trackers.

Suntec/Hexcel has manufactured and installed about 7,153 m^2 (77,000 ft^2) of thermal concentrating collectors 4,830 m^2 (52,000 ft^2 Hexcel), 2,323 m^2 (25,000 ft^2 Suntec). Of this total, 6,503 m^2 (70,000 ft^2) are currently operating daily using flux-line tracking. Suntec has another 2,044 m^2 (22,000 ft^2) under fabrication, and other large collector fields are being designed and proposed.

Characteristics of the Suntec collector are presented below:

- Advantages:
  - Is viable manufacturer
  - Meets STEOR temperature requirements
  - Offers good collector efficiency
  - Has large collector aperture, thus requires fewer drives and controls
  - Uses mirror material that can be patched
  - Has potential for glass mirror
  - Has considerable operating experience
  - Has receiver that can be disassembled for cleaning and/or replacing
  - Has experience with FEK-244 and glass mirrors.
- Disadvantages:
  - Large collector aperture requires larger supports and foundations.
  - Long focal length increases end losses.
  - Size is significantly larger than Sandia EPT.

- Potential problems:
  - FEK-244 durability.
  - Aluminum honeycomb lack of durability.
- Maintenance considerations:
  - Receiver is easy to disassemble, clean, and/or replace.
  - Chain drive requires care.
  - Steel torque tube requires painting.
  - FEK-244 requires gentle cleaning.
- Environmental and weather deterioration:
  - FEK-244 has shown deterioration from environment and weather.
  - Steel torque tube requires painting.
- Installation parameters:
  - Mirrors shipped in halves; attached to torque tube at site.
  - Mirror half pointing adjustable; receiver position adjustable.

4.2 System Trade-Off Studies

In the evaluation of potential system concepts, preliminary designs were prepared. The design for the flash-separator/feedwater-preheat-with-storage concept that emerged from the selection process had the following characteristics:

- The collector field employed 5.3 m (17.5-ft) axis-to-axis spacing between Sandia EPT collectors.
- The field was laid out in four "fingers" between existing and future wells.

o The collectors were oriented on a north-south axis.

o A gravel bed was placed beneath the collectors.

o Insulation of conventional thickness was employed.

All these characteristics are appropriate subjects for trade-off studies to optimize system design. Other aspects of the design were specific to the Edison field. Therefore, to demonstrate the applicability of this design to other oil fields and to other locations, additional trade-off studies were performed. In these studies the object was to minimize the levelized cost of the solar thermal energy delivered without introducing undue technological risks or safety hazards. In each case the levelized cost was determined by a discounted cash flow analysis technique using the appropriate capital, operating and maintenance costs for the system under study. Other economic assumptions made in the analyses are presented in Table B.2, Appendix B. The quantities of energy delivered were estimated through the simulation of the system using Honeywell, Inc.'s SUNSIM computer program. This program performs quasi-transient analyses using a deterministic model of the system. The collector efficiencies assumed are somewhat conservative.

In modeling the system it was assumed that between February 3 and November 27 ("summer"), both the preheating of water and the generation of steam are always attempted. Accordingly, the advantages of using the entire field to preheat water when low insolation is anticipated in summer are not shown. In "winter" (the period between November 27 and February 3) the whole field is devoted to preheating water. It is also assumed that the system is completely available at all times.

To perform the simulation, data was taken from the Fresno Typical Meterological Year (TMY) weather data tape. The direct normal insolation (DNI) data provided in this tape is close to that measured directly and, accordingly, can be regarded as being a good representation of real DNI data. A description of all the trade-off studies is presented in this section.

The annualized cost of energy figures in this section are based on before tax, equal annual 1979 dollar costs as calculated by Foster Wheeling using P.R.P. life cycle cost calculation method and assumptions described in Appendix I and Appendix B. In sections 1 and 8, Exxon has calculated after tax annualized energy cost estimates which are based on equal annual current dollar (decreasing annual constant dollar) energy costs. To a first order, the before tax P.R.P. method Foster Wheeler values can be multiplied by 0.39 to approximate comparable after tax Exxon values, given equivalent cash flows and incentives.

4.2.1 COLLECTOR ORIENTATION

The orientation of solar collectors restricted to motion about a single axis effect both their daily and annual thermal performance. In Table 4.6 the results of a simulation of system performance are presented for both east-west and north-south collector orientation. The results of the simulation show that with a north-south orientation, 11 percent more energy is collected annually than with an east-west orientation, this increase being reflected principally in a fall in steam production. This condition is not expected with the operational procedures adopted for this system, because with the north-south collector orientation more energy is collected in summer months and less energy in winter months. However, east-west orientation provides a potentially more uniform energy output. Nevertheless, because inclement winter weather belies the possible advantages of this more uniform energy output, north-south orientation is manifestly preferable to east-west orientation.

4.2.2 COLLECTOR SPACING

A 5.3 m (17.5 ft) axis-to-axis spacing of the collectors almost eliminates shading between the Sandia EPT collectors and thus represents a field that collects a maximum amount of incident energy. To optimize the preliminary design, this spacing was systematically reduced and the effect on system performance determined. The advantages of colser spacing include:

- o Less required header pipe (with a corresponding reduction in the number of necessary hangers and supports and in the amount of required insulation)
- o Lower heat losses from piping
- o Lower friction losses in header pipes
- o Less land usage
- o Lower thermal capacitance of system (that permits quicker warmup).

The disadvantage of closer spacing is increased collector-to-collector shading with a corresponding decrease in total collected energy.

Table 4.6

Effect of Collector Orientation on System Performance

Energy Description	Reducing Effect*	East-West Orientation Energy Collected (10^9 Btu/yr)	East-West Orientation Effect* (%)	North-South Orientation Energy (10^9 Btu/yr)	North-South Orientation Effect* (%)
Direct normal insolation	---	176.5	---	176.5	---
Incident	Cosine	138.8	76	153.8	87
Energy available	Shading and end losses	130.7	98	141.9	92
Energy collected	Average efficiency	67.3	51	74.8	53
Energy delivered	Thermal losses	59.2	88	66.9	89
Energy delivered as steam	---	30.9	---	38.0	---
Energy delivered as preheated water	---	28.3	---	28.9	---

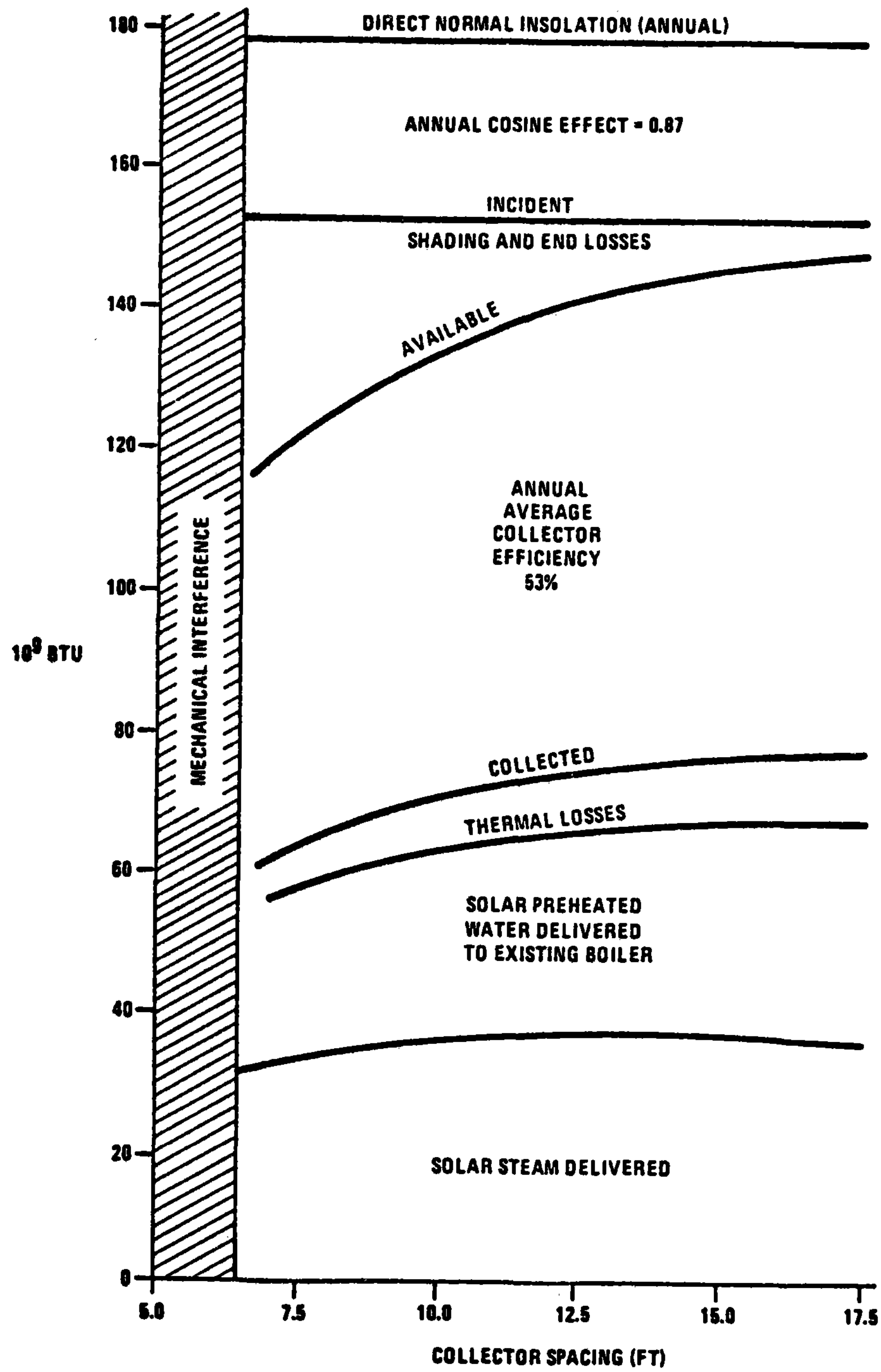
*This effect reduces the available energy shown in the energy column by the percentage indicated in the corresponding effect column.

10^9 Btu/yr = 1.055×10^{12} J/yr

Results of the investigations into collector spacing are shown in Figure 4.4. The annual direct normal insolation (taken from the Fresno TMY tape) is 18.62×10^{13}J (176.5×10^9 Btu). The annual average cosine effect is 87 percent, resulting in an incident energy of 16.23×10^{13}J (153.8×10^9 Btu) before shading and end losses. These losses increase with decreased collector spacing; however, the thermal losses from header piping also decrease with decreased collector spacing. Thus the total amount of energy delivered, as steam and preheated water, is only slightly sensitive to the decreased collector spacing.

Before the simulation results and economic calculations are examined in greater detail, an additional effect of decreased collector spacing should be discussed. A reduction in collector spacing to 3.8 m (12.5 ft) or less allows the collector field to be laid out in three "fingers," thereby eliminating one finger. Thus not only is land use decreased and easier access to an increased portion of the field allowed, but also the capital costs of and heat losses from the headers that connect one of the fingers to the others are eliminated.

For each collector spacing, the capital cost of the system was estimated and the cost of solar thermal energy determined (see Table 4.7). Evidently a 3.8 m (12.5-ft) separation allowing the collectors to be laid out in three fingers provides the least expensive solar-thermal energy when the collector spacing is identical in both the preheat and steam-generator fields. However, a further question that may be asked is whether different spacings in the preheat and steam-generator collector fields might not be advantageous. The simulation reveals that steam generation peaks at a 10-ft separation, while the supply of feedwater preheated to 121°C (250°F) falls as separation decreases. Although this fall can be ascribed partly to the decreased quantity of preheated water made available in the heat-recovery stage of operation (owing to the decreased thermal mass of the system), the simulation does not answer the question as to whether in the preheat field, with its lower heat losses, a collector separation greater than that employed in the steam generator field might be advantageous. To further investigate this question a simulation was performed with the separation of collectors in the preheat field set to 5 m (15 ft) and in the steam generator field to 3 m (10 ft). The results (Table 4.7) show no advantage to this arrangement. Accordingly, we may tentatively conclude that a uniform 3.8 m (12.5-ft) collector separation is best for this system when collectors of the dimensions and characteristics of Sandia EPT collectors are used. We should, however, note that if larger aperture collectors, lower temperatures, or reduced flow rates are employed, the optimal collector spacing will increase.



<u>NOTE</u>: 1 Ft = .3048 m

1 Btu = 1.055×10^3 J

Energy vs. Separation

Figure 4.4

Table 4.7

Effect of Collector Spacing on System Performance

Collector Axis-to-Axis Separation (ft)	Energy Delivered (10^9 Btu/y)	Cost of Energy ($/$10^6$ Btu)
17.5	68.0	32.89
15.0	67.6	32.85
12.5	66.9	32.79
10.0	64.6	33.61
7.5	60.1	35.84
10.0*/15.0†	66.0	33.09

*Steam-generator field.
†Preheat field

1 ft = .3048 m
10^9 Btu/yr= 1.055 x 10^{12} J/yr
$/$10^6$ Btu = $/1.055 x 10^9 J

4.2.3 WELL SPACING

The effect of well spacing was investigated by examining the layout required to place the collectors needed in this flash-separator/feedwater preheat-with-storage design between up to four rows of wells, with a well spacing ranging from 1.62 x 10^3 m^2 (0.4) to 20.2 x 10^3 m^2 (5) acres. In preparing the layouts we first assumed that the wells would be drilled in five spot patterns and that alternate rows of wells, lying on an east-west axis, had not yet been drilled. For these wells a 30 m x 61 m (100 x 200-ft) clear area will be required around each well. Existing wells require only a 9 m (30-ft) access way. The layouts are described in Table 4.8 and shown in Figures 4.5 through 4.9. The changes in the piping layout, the capital cost of the system, the solar-thermal energy delivered as steam and preheated water, and the cost of this energy are presented in Tables 4.9 and 4.10.

The major conclusion that can be drawn from these results is that significant reductions in the cost of solar energy can be made if the number of collector motors, trackers and connections from receiver tubes to distribution piping are reduced. Increased well spacing can also eliminate certain headers. Thus we see that at a 1.62 x 10^3 m^2 (0.4)-acre well spacing where single 6 m (20-ft)-module collectors must be used, the cost of energy is \$54.22/10^9J (\$57.20/10^6 Btu), whereas at a 4.73 x 10^3 m^2 (1.17)-acres well spacing with 24 m (80-ft) collectors, a cost of \$30.85/10^9J (\$32.54/10^6 Btu) is achieved. And at a 20.2 x 10^3 m^2 (5)-acre spacing with 37 m (120-ft) collectors in the preheat field, the cost of solar thermal energy falls further --to \$29.72/10^9J (\$31.35/10^6 Btu). If, however, only 24 m (80-ft) collectors are used with a 20.2 x 10^3 m^2 (5)-acre well spacing, the cost of solar-thermal energy is only reduced to \$30.14/10^9J (\$31.79/10^6 Btu).

Although we have studied a wide range of well spacings, our evaluations have been made for a single conceptual design. If longer strings of collectors in series can be used in the entire field (rather than only in the preheat field, as here), further cost reductions can be achieved for larger well spacings. Equally longer collectors can also be used if the collectors are to be placed between rows of existing wells where no requirement for a large drilling area exists. This is particularly important at smaller well spacings--at a 0.4-acre well spacing, 18 m (60-ft) collectors could be installed between the rows of wells if no drilling space is required. Conversely, if a 30 m x 61 m (100- x 200-ft) clear area is required around each well, whether existing or proposed, the placing of collectors within a 1.62 x 10^3 m^2 (0.4) acre well spacing is impossible and the costs associated with 3.2 x10^3 m^2 (0.8) and 1.62 x 10^3 m^2 (1.17) acre well spacings increase (Table 4.11).

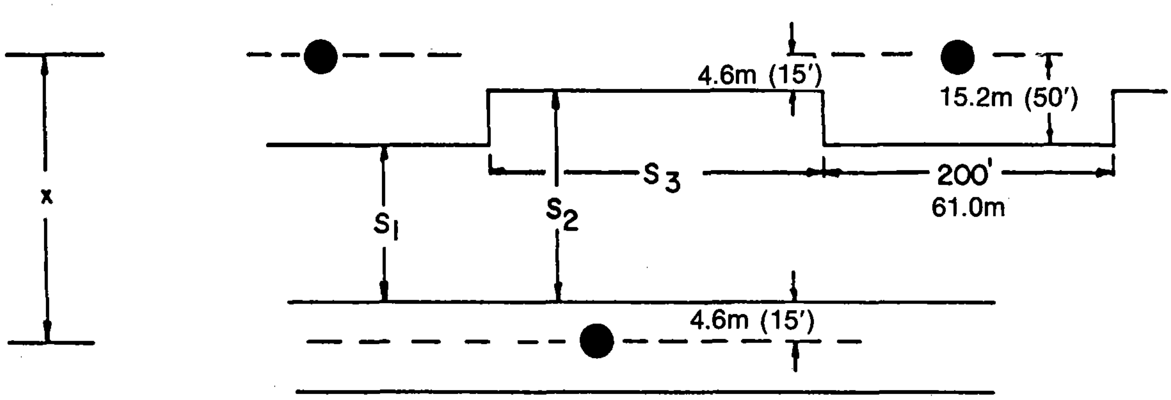
Studies performed in this project and described elsewhere in this report indicate that such a clear area is generally required, though this is not necessarily the case at the Edison field.

Table 4.8

Layout of Existing Wells

Well Spacing (acres)	Well Spacing Dimensions x	S1	S2	S3	Allowed String Length*	Aperture Area †
1.62×10^3 m^2 (0.4 acres)	28.3 m (93')	8.5 m (28')	---	---	6.1 m (20')	0.105
3.2×10^3 m^2 (0.8 acres)	40.2 m (132')	20.4 m (67')	31.1 m (102')	19.5 m (64')	18.3 m (60')	0.222
4.73×10^3 m^2 (1.17 acres)	48.8 m (160')	29 m (95')	39.6 m (130')	36.5 m (120')	24.4 m (80')	0.244
10.1×10^3 m^2 (2.5 acres)	71.0 m (233')	51.2 m (168')	61.9 m (203')	81.4 m (267')	48.8 m (160')	0.335
20.2×10^3 m^2 (5 acres)	100.6 m (330')	80.8 m (265')	91.4 m (300')	140.2 m (460')	73.2 m (240')	0.355

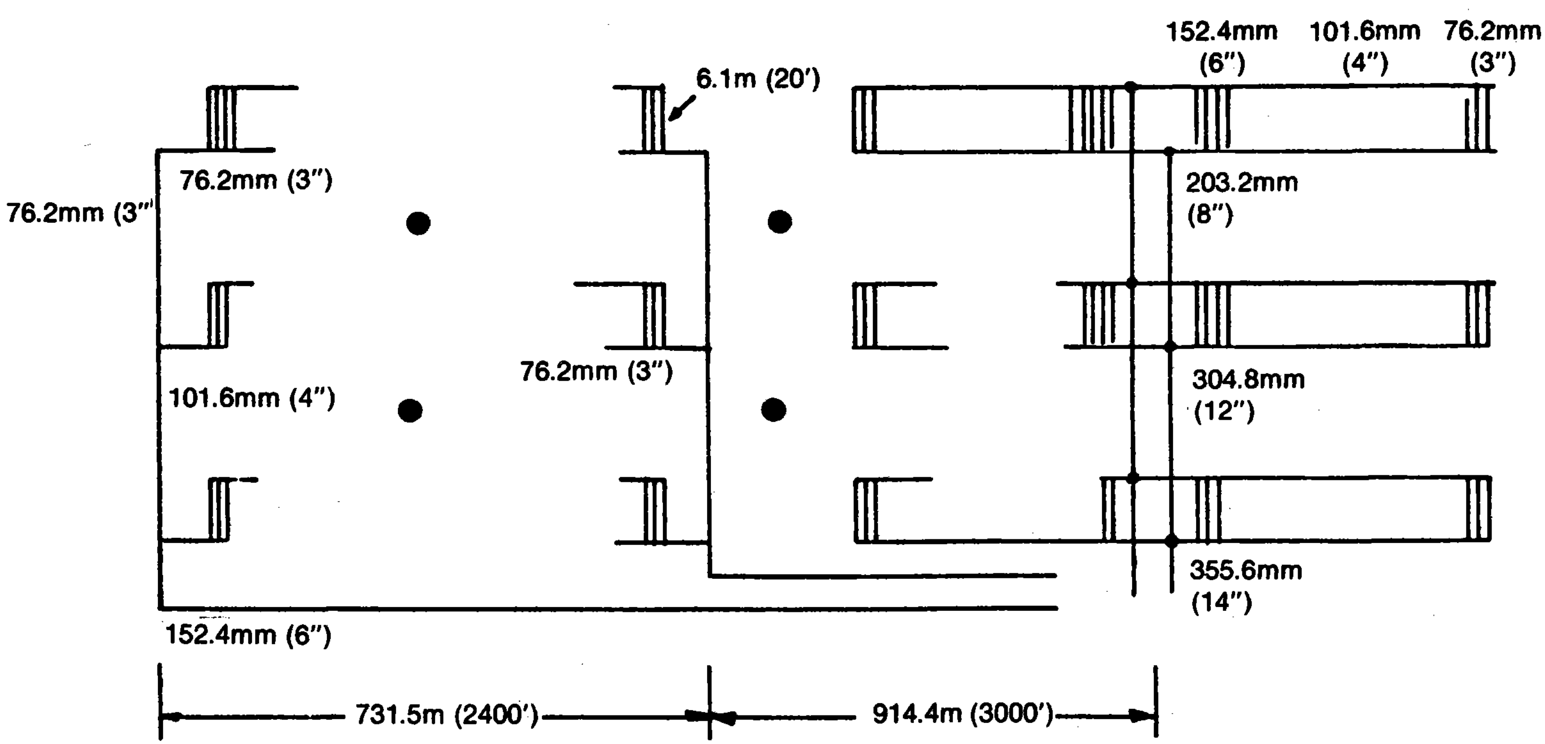
*North-South oriented collectors
†Expressed as a fraction of the total area covered by collectors, wells, and access ways.



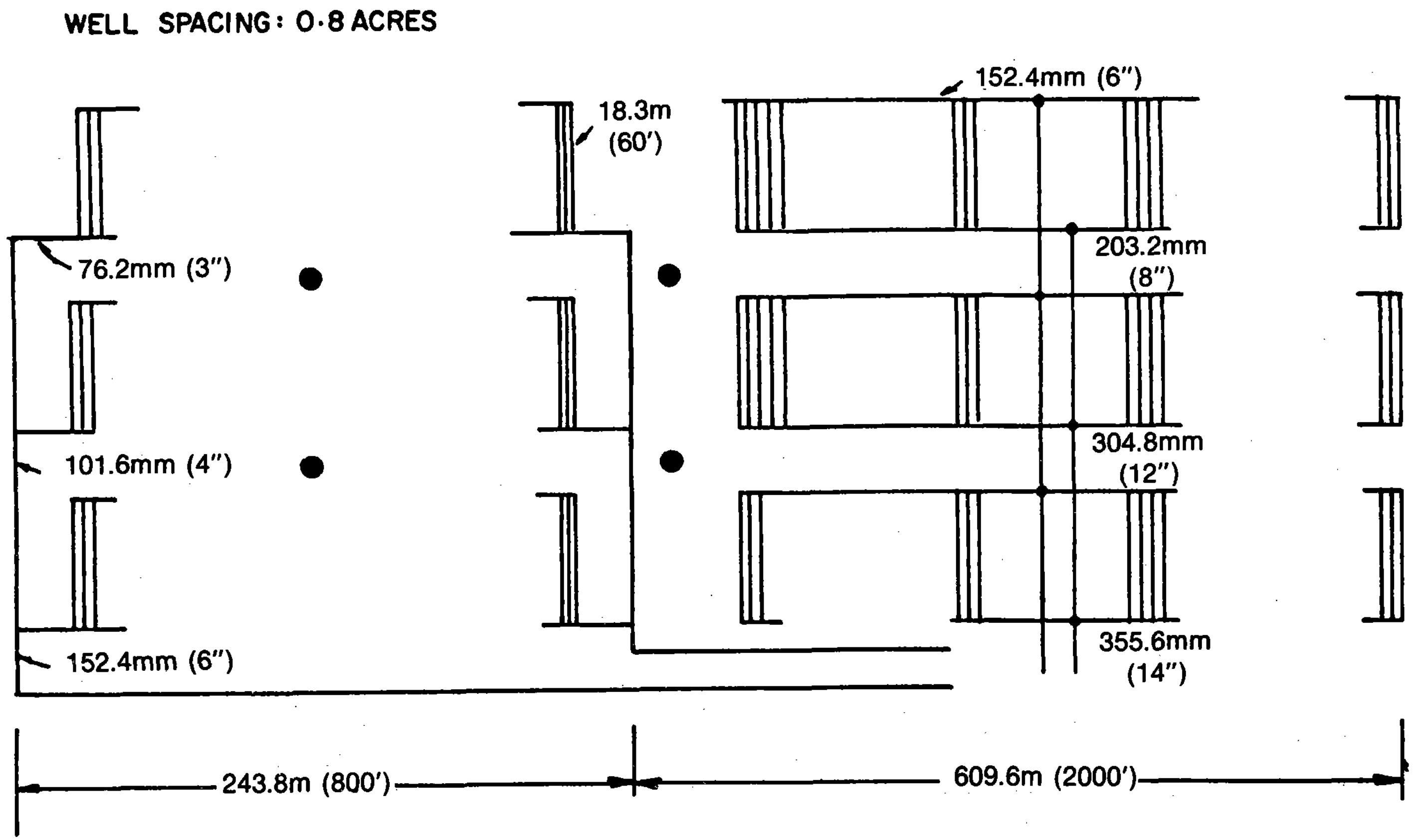
Well Spacing Dimensions

Figure 4.5

WELL SPACING 1.62 x 10³m² (0.4 ACRES)

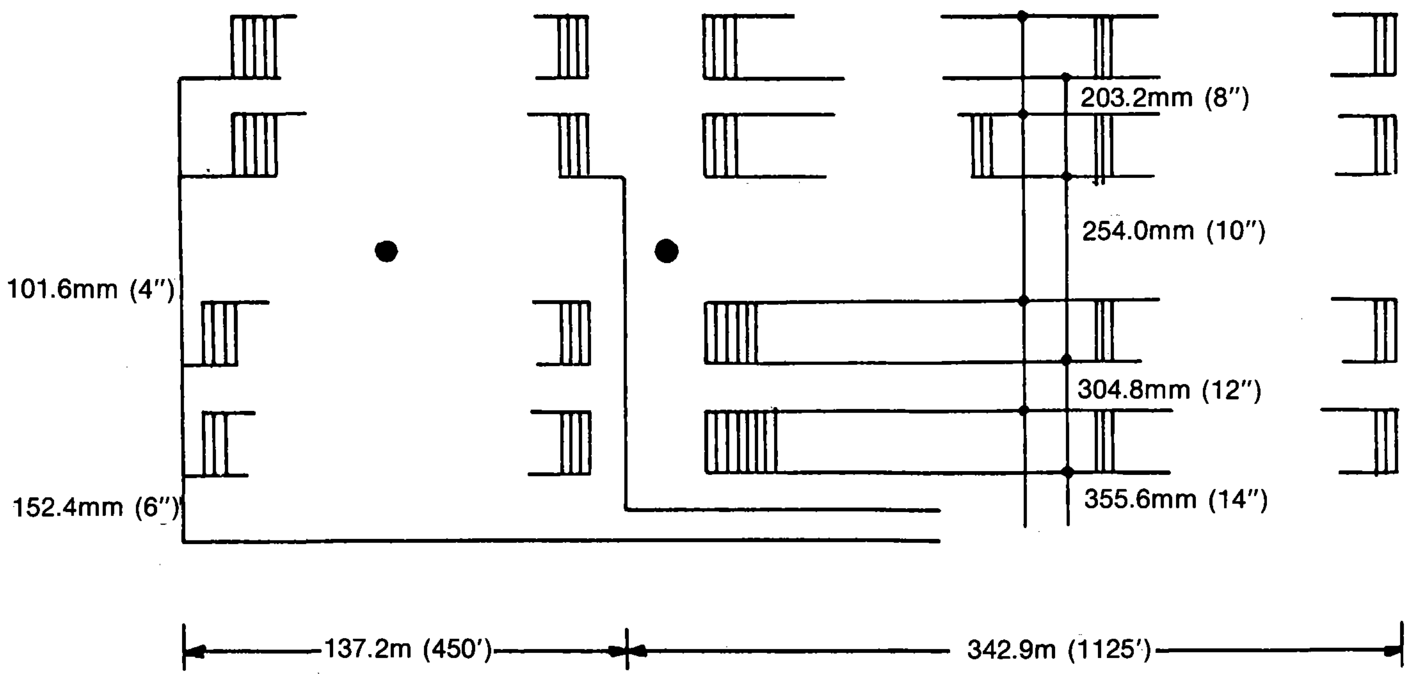


Collector Field Layout 1.62 x 10³m² (0.4 ACRES)
Figure 4.6



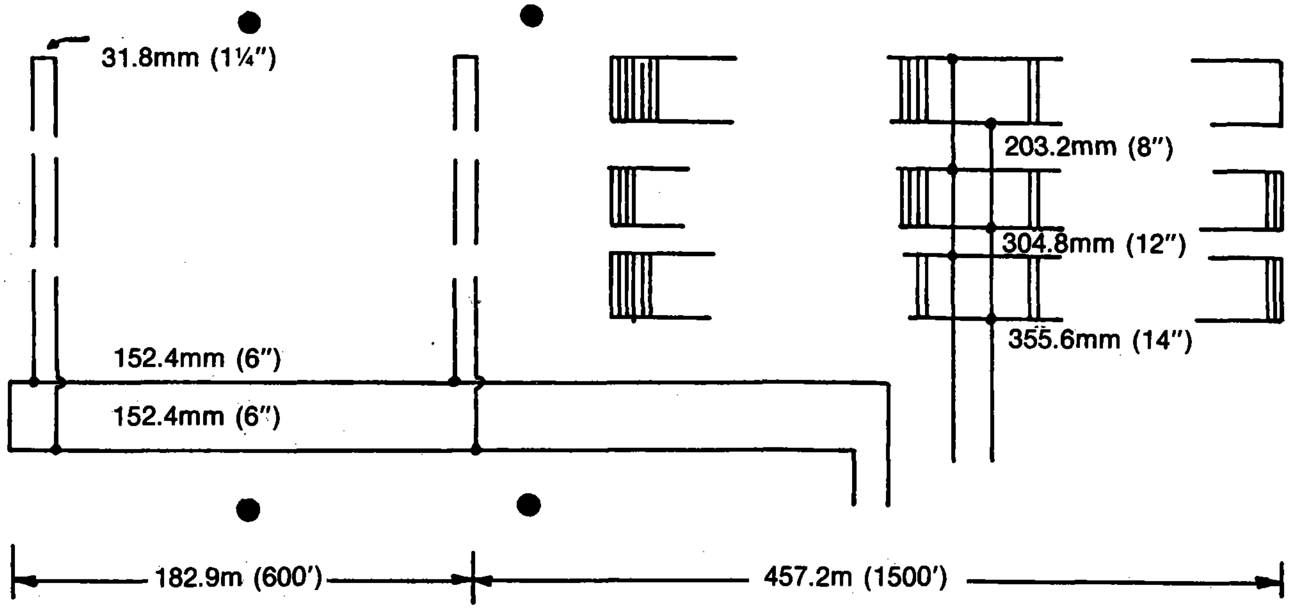
Collector Field Layout 3.2 x $10^3 m^2$ (0.8 ACRES)
Figure 4.7

WELL SPACING: 10.1 x 10³m² (2.5 ACRES)



Collector Field Layout 10.1 x 10³m²(2.5 ACRES)
Figure 4.8

WELL SPACING: 20.2 x $10^3 m^2$ (5 ACRES)



Collector Field Layout 20.2 x $10^3 m^2$ (5 ACRES)
Figure 4.9

Table 4.9

Changes in Piping Lengths

Collector Field	Pipe Size (in.)	Insulated/ Uninsulated	Changes in Piping Lengths (ft) Well Spacing (acres)				
			0.4	0.8	1.17	2.5	5
Preheat	1-3/4	I	0	0	0	0	240
	3	I	10,720	1,180	0	-1,800	-3,600
		U	-60	-20	0	-120	-200
	4	I	-60	-20	0	80	-200
		U	-60	-20	0	80	-200
	6	I	2,250	2,250	0	-187	600
		U	4,050	450	0	-337	0
Steam Generation	3	I	12,000	0	0	0	0
	4	I	12,000	0	0	0	0
	6	I	3,000	3,000	0	0	0
	8	I	-120	-40	0	-100	-200
	10	I	0	0	0	200	0
	12	I	-120	-40	0	-100	-200
	14	I	-60	-20	0	0	0

1 inch = 25.4 mm

1 ft = .3048 m

1 acre = 4.047×10^3 m^2

Table 4.10

Impact of Well Spacing

Well Spacing (acres)	Collector Length (ft)	Changes in Collector costs* ($)	Change in Piping Costs † ($)	Change in Thermal Losses (10^9 Btu/yr)	Cost of Energy Delivered ($/$10^6$ Btu)
0.4	20	3,907,872	1,741,203	11.57	57.20
0.8	60	488,042	246,224	2.07	35.46
1.17	80	0	0	0	32.54
2.5	80	0	-89,633	-0.39	32.14
5	80	0	-154,320	-0.83	31.79
5	120/80 §	-118,867	-154,320	-1.13	31.21

*Includes the cost of instrumentation, motors, foundations, fittings, and electrical wiring.
†Includes the cost of piping, supports, insulation, gravel etc.
§Collectors of length 36.6m (120 ft) are used in the preheat field.

1 acre = 4.047×10^3 m^2

1 ft = .3048 m

10^9 Btu/yr = 1.055×10^{12} J/yr

$/$10^6$ Btu = $/$1.055 \times 10^9$J

WELL SPACING: 3.2×10^3m^2 (0.8 ACRES)

Table 4.11

Effect of Well Spacing - Clear Area Around Each Well
(Changes From Base Case)

Well Spacing	Pipe Length Change m (ft)	Pipe Length Pipe Size mm (in.)	Capital Cost ($ x 10^6)	Heat Delivered 10^{12} J/yr (10^9 Btu/yr)	Cost Of Energy Delivered $\$10^9$J ($/10^6 Btu)
3.2×10^3 m^2 (0.8 acres)	609.6 m (2000')	76.2 ("3)	1.48	-5.70 (-5.40)	4.97 (5.24)
	1463 m (4800')	152.4 (6")			
4.73×10^3 m^2 (1.17 acres)	153.6 m (504')	76.2 (3")	0.27	-0.92 (-0.87)	0.31 (0.33)
	384 m (1260')	152.4 (6")			

(1) A (30.5 m. x 71 m.) 100 x 200 ft clear area is left around each existing or prospective well.

(2) At a 1.62×10^3 m^2 (0.4) acre well spacing there is no room for collectors.

(3) With 3.2×10^3 m^2 (0.8) and 4.73×10^3 m^2 (1.17) acre well spacing, the collectors are laid out in a staggered pattern. With 10.1×10^3 m^2 (2.5) and 20.2×10^3 m^2 (5.0) acre well spacing this is not required. The base case design has 4.73×10^3 m^2 (1.17) acre well spacing with only an access road to and no clear area around alternate rows of wells.

It should be noted that a staggered collector layout may be necessary if the wells are not placed in east-west rows and if the collectors must still lie in a north-south direction. The conclusions drawn here as to the effect of well spacing would, however, be applicable in this case. An alternative layout in which the collector field is located away from the wells is discussed in the following subsection.

4.2.4 LOCATION OF SOLAR COLLECTORS AWAY FROM THE WELLS

The placing of solar collectors in a remote location rather than among the wells offers several advantages:

- Allows easier access to existing wells
- Places no restriction on where additional wells can be drilled
- Allows a more compact collector field to be used, with longer collectors or strings of collectors where appropriate.

These advantages are gained, however, at the cost of the increased capital expenditure for and heat losses from the pipes that carry water and steam from the solar collectors to the wells.

In studying the effect of locating the collector field away from the wells, we assumed that the collector field would be laid out as if it were to be placed between wells with a 5-acre well spacing and with 37 m (120 ft) of collectors in the preheat field. Water and steam lines of 21°C (70°F) and 121°C (250°F) will run between the collector field and the wells. The effect of the separation between the collector field and the wells will then be examined.

In selecting an appropriate line size for the transport of preheated water from the remote location into the oil field, trade-off studies must be performed. While capital costs and annual heat losses diminish with line diameter, pumping costs (pressure drop) increase. Furthermore standard design practices place an upper limit on the velocity of water flow within a line.

Similarly, in considering the transport of steam to the oil field, we observe that capital costs and heat losses diminish with line diameter. However, given that the allowable pressure drop along the length of pipe is limited to 448×10^3 Pa (65 lb/in^2) [5.97×10^6 Pa absolute (865 lb/in^{2}a) steam-generation pressure, 5.52×10^6 Pa absolute (800 lb/in^{2}a) required well-head pressure], steam can be carried only relatively short distances in small-diameter lines. These factors and the results of trade-off studies are presented in Table 4.12 and Figure 4.10. The optimal steam-line size for solar thermal system well separation can be selected from Figure 4.10. Note that the capital cost estimates for steam line include line insulation of optimal thickness (based on a steam cost of \$23.7/10^{9}J (\$25/10^6 Btu) and forged steel thermodynamic steam traps placed in the lines.

4.2.5 FOUNDATION DESIGN

Sandia Laboratories have identified collector foundations as one part of a solar thermal system using distributed collectors where cost reductions can be made. Accordingly, we have examined a variety of foundation designs appropriate for the Sandia EPT collector. Because at present no design criteria for solar collector foundations exist in the codes and standards, three approaches were taken to determine loads: applied wind loads were computed assuming full loadings per the Uniform Building Code, reduced wind loads were computed per the Uniform Building Code for Miscellaneous Structures, and wind loads calculated from wind-tunnel tests. Even though the Edison field is located in a very severe earthquake zone (Zone 4), seismic loading does not govern the design, because the solar collectors are comparatively light. The results indicate that the full wind loads determined according to the Uniform Building Code lead to a significantly more conservative foundation design than do the alternative methods of determining wind loads. In contrast, the reduced wind loads obtained by assuming the solar collectors to be in the Uniform Building Code's miscellaneous category give only slightly heavier foundations than do the wind loads derived from the wind-tunnel data. Accordingly, we recommend that the reduced wind loads calculated by assuming that the collectors fall into the Uniform Building Codes miscellaneous category be adopted for foundation design. This method represents a more established methodology of determining wind loads.

Of the foundation types evaluated, the double-pier foundation scheme was found to be the most cost-effective. It is also intrinsically a more stable design than the single-pier concept. Thus we recommend that the double-pier foundation design be adopted. This recommendation is expected to hold for wider-aperture collectors. The details of this study on foundation designs are presented in Appendix C.

4.2.6 INSULATION THICKNESS

If insulation of a conventional thickness were to be used in this solar-thermal system, heat losses from the piping and vessels would amount to 10 percent of the total energy collected. Because solar-thermal energy costs \$28.4/10^{9}J (\$30/10^6 Btu) and conventional insulation thicknesses are based on energy costs of \$2.84/10^{9}J (\$3/10^6 Btu), thicker insulation may be warranted.

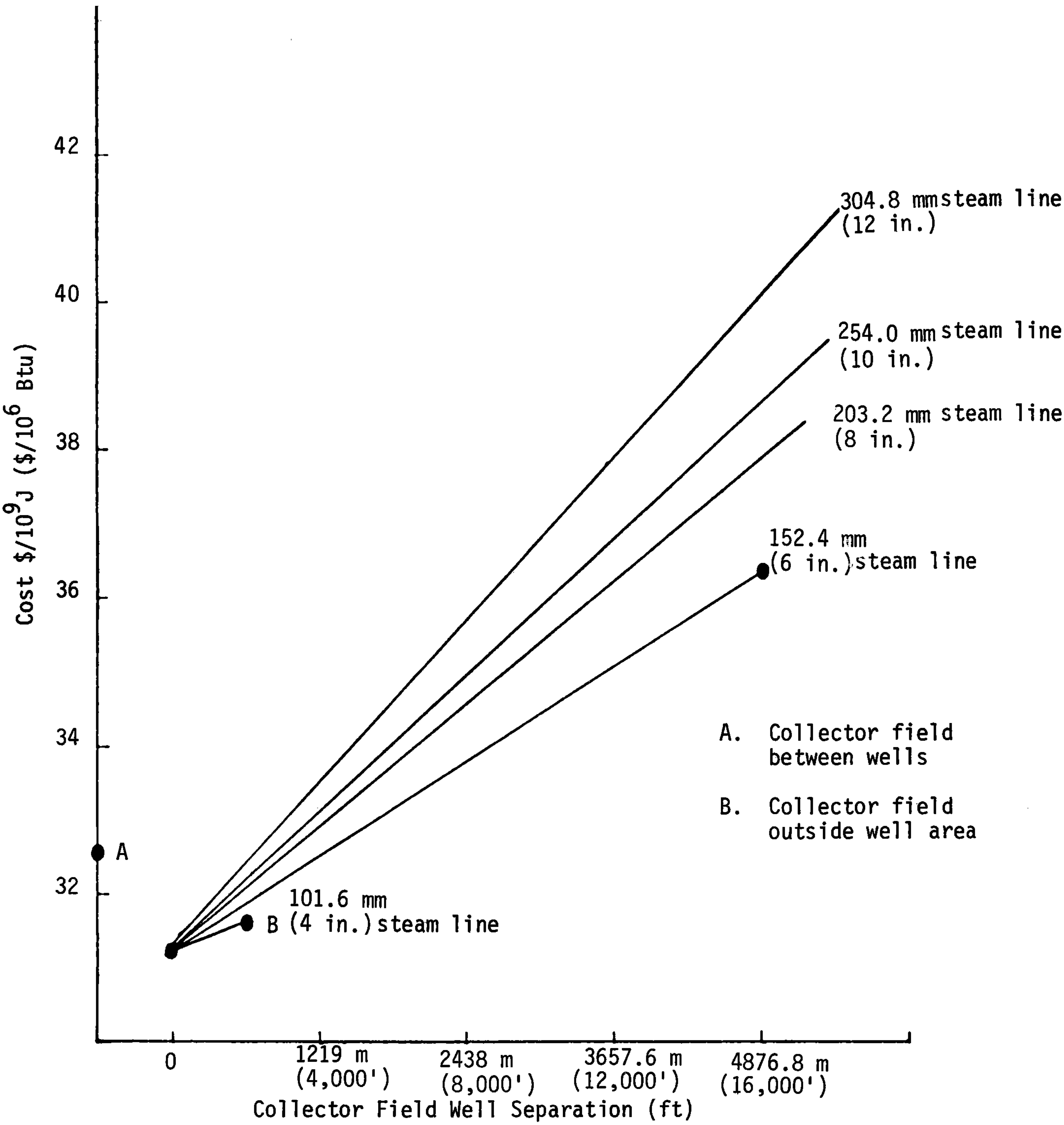
Table 4.12

Comparison of Steam Line Sizes

Line Diameter* mm	(in.)	Pressure Drop kPa/m	(lb/in^2 ft)	Steam Velocity M/S	(ft/s)	Allowed Length of Line m	(ft)
101.6 mm	(4)	70.74	(3.127)	16.18	(53.10)	640	(2,100)
127 mm	(5)	22.44	(0.993)	10.23	(33.55)	1981	(6,500)
152.4 mm	(6)	9.13	(0.404)	7.14	(23.42)	4907	(16,100)
203.2 mm	(8)	2.24	(0.099)	4.08	(13.37)	19,995	(65,600)
254.0 mm	(10)	.723	(0.032)	2.59	(8.50)	61,874	(203,000)
304.8 mm	(12)	.294	(0.013)	.003	(0.01)	152,400	(500,000)

*Schedule 80 pipe.

To deliver 12,701 Kgm/h (28,000 lb/h) of steam at a 5.97×10^6 Pa absolute (865 lb/in^2) an inlet pressure with an allowed pressure drop in the line of 448×10^3 Pa (65 lb/in^2).



Comparison of Costs for Various Steam Line Lengths and Line Sizes

Figure 4.10

The properties of a series of rigid thermal-insulating materials have been reviewed to identify appropriate materials for use with distributed collector solar thermal systems.* Based on installed cost, resistance to abuse and moisture, and ability to function effectively in a -17 to 315°C (0 to 600°F) temperature range, calcium silicate, mineral wool, fiberglass, and cellular glass appear to be appropriate insulation materials. Because of its lower cost, easier handling, and excellent moisture resistance, fiberglass insulation is recommended for this project.

To determine the most cost-effective insulation thicknesses for each line and for flat surfaces, the insulation thickness in each surface or line was increased in 0.01 m (0.5-in.) steps until the incremental cost of energy saved exceeded $23.7/10^9$J ($25/10^6$ Btu). This incremental cost was calculated on the same basis as the system cost. The optimal insulation thicknesses are presented in Table 4.13. Table 4.14 compares these thicknesses to those commonly adopted for nonsolar industrial plants. It is evident that in solar-thermal systems, thicker insulation than normally used is desirable.

It should be noted that the type and thickness of insulation recommended for use in this system are similar to those recommended to Sandia Laboratories in the Jacobs Engineering Group study. However, we emphasize that the means they use to calculate the optimum insulation thickness differ substantially from ours and thus a more detailed study would be required to determine if the similarity in conclusions is merely coincidental.

4.2.7 GROUND COVER

Though standard engineering practice calls for a gravel bed around all equipment, laying gravel beneath a 23,226 m^2 (250,000 ft^2) collector field represents an expenditure of approximately $160,000 and serves no important function. All that is required of the ground surface in this collector field is that no vegetation grow taller than 0.3 m (1 ft), that vegetation not represent a fire hazard, and that ground cover not exacerbate dust problems. As the soil near Edison tends to drain rapidly, it is possible to walk on it 2 to 3 hours after rain ceases or to drive over it in a light truck 6 to 10 hours later without disturbing the ground. Accordingly, there is little incentive to spread gravel to prevent muddy conditions.

Two alternatives to laying gravel are to plant ground cover or to sterilize the soil. Soil sterilization would require that herbicides be sprayed every 7 years, at a cost of $1,500 each time. Though leaching of the herbicide from the surface would take an additional 7 to 10 years after the removal of the collectors, the use of selective herbicides would allow replanting of the field

*Jacobs Engineering Group, Incorporated, "Draft Interim Report on the Solar Collector Field Optimization Study," prepared for Sandia Laboratories, September 13, 1979.

Table 4.13

Optimum Fiberglass Insulation Thicknesses*

Field/ Temperature	Pipe Size (in.)	Insulation Thickness (in.)	Heat Loss (Btu/linear ft)	Pipe Surface Temperature C (°F)	Capital Cost ($/linear ft)
Preheat/121°C (250°F)	1.25	2.5	18	18.3°C (65°F)	10.19
	3	2.5	28	19.4°C (67°F)	11.00
	4	2.5	34	20°C (68°F)	9.45
	6	2.5	44	20°C (68°F)	14.15
	FLAT	5.0	10	18.9°C (68°F)	5.25†
Steam Generation/ 282°C (540°F)	1-1/4	4.0	49	20.6°C (69°F)	13.70
	6	5.0	93	22.8°C (73°F)	24.27
	8	5.0	111	22.8°C (73°F)	26.15
	12	5.0	147	22.3°C (74°F)	33.67
	14	5.0	158	23.9°C (75°F)	41.92
	FLAT	5.0	61	23.3°C (74°F)	

*Based on aluminium jacket, 60°F ambient temperature, 8 mph wind speed.
†Cost/lb/in^2.

1 in = 25.4 mm
Btu/linear ft = 3462 joules/meter
$/linear ft = $3.05/m

Table 4.14

Comparison of Insulation Thickness and Heat Losses

		Solar Thermal System		Conventional System	
Pipe Size	Operating Temperature (°F)	Insulation Thickness (in.)	Heat Loss* (Btu/linear ft)	Insulation Thickness (in.)	Heat Loss† (Btu/linear ft)
1.25	121°C (250°F)	2.5	18	1.5	59
	282°C (540°F)	4	49	2	138
3	121°C (250°F)	2.5	28	2	78
4	121°C (250°F)	2.5	34	2	86
6	121°C (250°F)	2.5	44	2	113
	282°C (540°F)	5	93	3	270
8	282°C (540°F)	5	111	4	266
12	282°C (540°F)	5	147	4	367
14	282°C (540°F)	5	150	4	406
	121°C (250°F)	5	10§	3	32
FLAT	282°C (540°F)	5	61§	5	61

*Based on aluminium jacket, 15.6°C (60°F) ambient temperature, 3.13 m/SEC(7 mph) wind speed

†Based on aluminium jacket, 26.7°C (80°F) ambient temperature, 3.13 m/SEC(7 mph) wind speed

§Expressed in Btu/ft^2.

1 inch = 25.4 mm

1 Btu/linear ft = 3462 J/m

immediately following the termination of solar thermal enhanced oil recovery operations and the removal of the collectors. Sterilization, however, lends itself to the creation of dusty conditions and would not be aesthetically pleasing.

Alternatively, ground cover appropriate for the semiarid climate at Edison can be planted; the Kern County Department of Agriculture recommends a hybrid Bermuda grass. To irrigate this ground cover, a low-level water-distribution system would have to be installed. The capital cost for planting and irrigation would be $20,000 and yearly irrigation and maintenance costs would amount to $3,000. Since this alternative would result in a pleasant field surface with a low propensity for muddy or dusty conditions, the planting and irrigation of grass or other ground cover is recommended for this solar thermal system at Exxon's Edison field.

4.2.8 LOWER STEAM PRESSURE REQUIREMENTS

In this project, the solar-thermal system has been designed specifically to meet a well-head requirement of 5.52×10^6 Pa absolute (800-lb/in^{2}a) steam. It is possible, however, to envisage modes of operation in which the solar steam generator provides steam at pressures lower than 5.52×10^6 Pa absolute (800 lb/in^{2}a) and the fired boiler is used to generate high-pressure steam when needed. Furthermore, it should be noted that at other oil fields where enhanced oil-recovery operations occur, lower steam-injection pressures are required. For all these reasons, it is appropriate to investigate the design and performance of a flash-separator/feedwater preheat-with-storage system when lower-pressure steam is required.

The generation of steam at lower pressures will allow the system to be operated at lower temperatures and/or with lower flow rates. With lower receiver temperatures, the collection efficiency will increase; with lower flow rates introduced by operating with increased temperature differentials, piping and insulation costs and parasitic power requirements and thermal energy losses are reduced. In either case the time taken to reach operating temperatures in the steam-generating collector field will be reduced.

These changes in the mode of operation will lower the cost of generating steam and allow more steam to be generated in the winter months, or whenever insolation is low. In addition, lower operating temperatures will reduce the safety and reliability problems associated with the circulation of pressurized water and allow the use of alternatives to flexible hoses between the receiver tubes and the distribution piping.

To examine these effects, we prepared three system designs for the generation of 27 6×10^6 Pa absolute (400-lb/in^{2}a) steam. The designs differed in the steam-generator collector-field outlet temperatures and in the optimal piping sizes and flow rates. As the collector outlet temperature increases, the size of lines decreases. The resultant lower thermal losses and capacitance compensate for the decreased collection efficiency at higher temperatures and the energy and time required to further raise the steam-generator-system temperature (see Table 4.15). The energy delivered annually is thus found to be 9 percent greater than that obtained when 5.97×10^6 Pa absolute (865-lb/in^{2}a) steam is produced, irrespective of the collector outlet temperature. An economic analysis of these designs shows that the delivered cost of solar thermal energy is up to 10 percent lower when steam is produced at 2.76×10^6 Pa absolute (400 lb/in^{2}a) rather than at 5.97×10^6 absolute (865 lb/in^{2}a); however, this cost is not greatly influenced by the collector exit-water temperature (see Table 4.15).

Because operation of the system at lower pressures is inherently safer, we recommend that the design using the lowest collector exit temperature be adopted. This is the safest and only marginally more expensive than the other designs. It is also the most flexible in that it can be operated at temperatures closest to the bounds imposed on the solar collectors. Indeed, this design is identical to that prepared to generate 5.97×10^6 Pa absolute (865 lb/in^{2}a) steam.

Before summarizing the conclusions of this study, we should give a caveat. If the field layout permits their use, longer collectors--with the lower flows necessitated by higher collector exit temperatures--will allow further cost reductions to be made beyond those presented in Table 4.15. Under these circumstances, a compromise between low system pressure and energy costs might be appropriate.

In summary, this study has shown that if a solar-thermal system is installed between oil wells spaced according to the requirements of Exxon's Edison field, the design we have chosen is optimal from safety and performance standpoints. If generation of steam at lower pressures is permissible, improved performance results. Unless the collector-field layout allows the length of collectors and collector strings used to increase beyond the 24 m (80 ft) permitted at the Edison field, little incentive exists to prepare designs that specifically make use of the increased temperature differentials allowed at lower steam pressures.

4.2.9 COLLECTOR LENGTH

Frequent reference has been made in these trade-off studies to the desirability of using longer collectors. Where this is feasible, the costs of headers, controls, motors, and connections between receiver tubes and headers are reduced. Furthermore, thermal losses from headers are reduced, and on a basis of energy collected per unit area of collector surface, so are shading and end losses. With these incentives for enhanced cost effectiveness, collector manu-

Table 4.15

Economic Analysis of Designs Producing Steam at Lower Pressures

Steam temperature	275°C (527°F)	229°C (445°F)	229°C (445°F)	229°C (445°F)
Collector outlet temperature	282°C (540°F)	238°C (460°F)	260°C (500°F)	282°C (540°F)
Line sizes	356 mm (14") 305 mm (12") 218 mm (8.6")	203 mm (8") 152 mm (6") 109 mm (4.3")	203 mm (8") 218 mm (8.6") 102 mm (4")	105 mm (4.14") 305 mm (12 ") 218 mm (8.6")
Energy delivered (10^{12} J/yr)	69.2	75.7	75.5	75.7
Electricity consumed (10^6 Kwh/yr)	1.74	1.74	1.75	1.78
Capital cost ($\$10^6$)	13.47	13.47	13.32	13.28
Cost of energy ($\$/10^9$J)	31.7	28.9	28.8	28.6

1 BTU = 1.055 KJ

facturers are now prepared to deliver 37 m (120-ft)-long collectors rather than the previously standard 24 m (80-ft)-long collectors and are discussing the production of 49 m (160-ft)-long collectors. Additional costs are incurred with longer collectors because more powerful drive mechanisms are needed, and strengthened torque tubes or frames may be required to prevent wind-induced twisting from defocusing the collectors at low wind velocities. An initial analysis performed on 160-ft-long Suntec collectors (of the current design) does, however, indicate that excessive twisting would not occur at the average wind velocity seen at the Edison field.

Eventually, an optimal collector length will be selected. This will be a compromise between the benefits and costs of increasing collector length.

4.2.10 EXTENT OF HEAT RECOVERY

When insolation falls, sensible heat remains in the water and metal of the solar-thermal system. The extent to which this heat may be recovered depends on both the rate at which the collector fields are flushed and the temperature in the steam-generator collector field at which heat recovery ceases.

By rapidly flushing the collector fields, we can reduce thermal losses from the system and parasitic power requirements. However, an excessively rapid flush may overfill the preheated feedwater storage tanks. We recommend, therefore, that flushing be as rapid as storage-tank water levels and water flow velocities in the collector fields allow.

If heat recovery in the collector fields proceeds to temperatures lower than 121°C (250°F), overnight heat losses will be further diminished and the energy delivered by the solar-thermal system will increase; if the temperature to which the steam-generator field falls is reduced to 65°C (150°F), the total energy delivered by the solar-thermal system increases by 1.5 percent. Should flushing continue to such a low temperature, we must ensure that adequate steam can enter the storage tanks to maintain a constant tank temperature of 121°C (250°F) or that the operation of the fired boilers will allow the use of feedwater at temperatures between 21°C (70°F) and 121°C (250°F). If the former procedure is adopted, it can be extended to maintain a constant supply of 121°C (250°F) feedwater from the storage tanks by heating 21°C (70°F) feedwater in the tanks when all the water preheated with solar energy has been pumped out.

4.2.11 REPLACEMENT OF REFLECTOR SURFACES

The polished aluminum and aluminum acrylic (FEK-244) reflector surfaces currently employed on solar collectors are prone to weathering. As this results in a lower reflectivity, periodically replacing the reflector surface may be desirable. Replacement should be made at a time determined by a trade-off between the cost of replacement and the mirror surface's lowered reflectivity. Because a fall in reflectivity results in both shorter periods of operation at design temperatures and a lower delivery rate of energy at these temperatures, the total energy delivered by the solar-thermal system will decline faster than the relative reflectivity.

Back-silvered glass is expected to be much less susceptible to weathering. While production problems will in all likelihood exclude the initial use of this material at Exxon's Edison field, a retrofit might be possible.

4.2.12 RECEIVER TUBE-HEADER CONNECTIONS

In tracking the sun, the receiver tube of a parabolic trough moves through an arc of 5 rad (270 deg) at a radius .6 m (2 ft). The connections between the receiver tubes and the headers must therefore be able to handle this movement. Five types of connections have been investigated:

- A simple length of flexible hose
- Flexible hose looped around a drum
- Three ball/self-aligning swivel joints
- A single swivel joint on the axis of rotation of the collector
- A single swivel joint and flexible hose.

These devices will now be evaluated. The costs quoted are for a complete insulated assembly.

4.2.12.1 Simple Length of Flexible Hose

- Advantages - The hose is capable of handling the temperatures and pressures of the steam generation field.
- Disadvantages - It is prone to premature failure from repeated flexing and torsion induced by squirming and thermal expansion.
- Cost - $430 for steam generation field, $300 for preheat field.

4.2.12.2 Flexible Hose Looped Around a Drum

This device, proposed by Anaconda Metal Hose, consists of a hose loosely looped around a drum. As the collector rotates, the hose winds and unwinds as shown in Appendix D.

- o Advantages - The device is capable of handling high temperatures and pressures and less subject to premature failure than a simple hose.
- o Disadvantages - The drum shades the collector. It is more costly than a simple hose.
- o Cost - \$500 for steam generator field, \$380 for preheat field.

4.2.12.3 Three Swivel/Ball Joints

This device consists of three ball joints/self-aligning swivel joints connected by piping.

- o Advantages - It has been proven in low-temperature service; easy to insulate.
- o Disadvantages - It is unable to handle the temperatures and pressures in the steam generator field with currently manufactured seals.
- o Cost - \$300 for ball joints, \$600 for swivel joints.

4.2.12.4 Swivel Joint

With this device, the water is removed in a pipe lying along the collector's axis of rotation. This pipe is connected by a swivel joint to a pipe branching up from the header.

- o Advantages - It is inexpensive.
- o Disadvantages - To prevent rotation being carried on to the header, a torque-resisting structural member is needed for the swivel joint. This adds rigidity to the system in resisting thermal expansion and thus transmits too much force back to the collectors. It is unable to handle high temperatures and pressures with current seals.
- o Cost - \$250.

4.2.12.5 Swivel Joint With Flexible Hose

This device is similar to the swivel joint device except that a flexible hose is placed in the vertical leg between the swivel joint and the header. This hose should be able to absorb thermal expansion in transverse directions.

- o Advantages - It is easy to insulate.
- o Disadvantages - It is more complex than a swivel joint alone. The header may have to be spring supported. It is unable to handle pressures and temperatures in the steam generation field.
- o Cost - $300

We conclude that for service in the steam generation field, either of the flexible hose designs can be used. For the preheat field, all but the swivel joint are feasible. The final selection of a connecting device should be made on the basis of cost and performance (lack of leaks/fatigue failure). To investigate this performance, a test procedure is presented in Appendix D. Though written for flexible hoses, this procedure is applicable to other connecting devices.

5. PRELIMINARY DESIGN FOR STEAM RAISING

This section details the preliminary design of a proposed solar thermal system for Exxon's field at Edison, California. The system is based on a flash-separator/feedwater preheat with storage concept working in conjunction with a single fired boiler.

The preliminary design is centered around the engineering flow diagrams, heat and material balances, performance calculations and equipment specifications. In preparing this description, particular attention has been paid to delineating the proposed modes of operation of the system and various aspects of the design. Safety, reliability and maintainability are also addressed.

Environmental factors must be considered an integral part of any design and are therefore included in this section. Permits required for construction and operation of the system are also included.

5.1 Description of System

5.1.1 PROCESS DESCRIPTION

In this solar thermal system, the collector field is divided into two portions. One is devoted to the preheating of water for solar and oil-fired steam generators, the other to collect solar energy for steam generation using a flash-separator.

The solar preheat collector field will heat boiler feedwater from 21°C to 121°C (70°F to 250°F) and the solar steam generator field will generate 5960 kPa absolute (865 lb/in^2a) saturated steam from boiler feedwater fed at 121°C (250°F). During the day preheated water at 121°C (250°F) is collected in the boiler feedwater storage tanks; water from these is fed to the solar steam generator field and to the fired boiler. Feedwater remaining in the storage tanks at the end of the day is fed to the fired boiler during the night. Other modes of operation provide the efficient utilization of energy in winter months, or whenever insolation is low, and for the recovery of sensible heat stored in the system at sunset.

Drawing 60035-1-50-1 is the engineering flow diagram (see Appendix E) for the solar thermal system. Descriptions of the operating modes of this system and the philosophy behind equipment selection and system design are given below. Additional details of the design basis for this solar thermal system, process equipment specifications, and a preliminary design for the solar controls are provided in Appendices E and F.

5.1.2 SYSTEM OPERATING MODES

In all the operating modes water will be fed to the fired boiler by a feedwater pump from tanks TK-101A/B or from the feedwater treatment system.

5.1.2.1 Warm-Up Mode

After sunrise, a solar intensity detector wakes up the system when the intensity of radiation reaches 158 w/m^2 (50 $Btu/h/ft^2$). If the wind speed is below 13 m/s (30 mph) (NSH-1 not on) and the demand switch (HS-16) is on, XSH/L-1 starts the following pieces of equipment.

- o Timer KC-1A
- o Pump P-101 to pump water from the feedwater treatment system to the tanks TK-101A/B through the preheat field
- o Pump P-103 (if the water level in D-101 is not very low as indicated by LSLL-15) to circulate water from D-101 through the steam generator collector field.

Flow switches FSL-4 and FSL-7 will detect flow and send signals to the field controls UC-100A/B/C and UC-400 A/B/C/D which in turn send tracking signals to the controllers mounted on each collector. These signals cause the collectors to unstow and begin tracking the sun.

As the preheat zone warms up to 121°C (250°F), loop TC-2 will begin to control the flow of water through the preheat collector field so as to maintain a 121°C (250°F) water temperature entering the storage tanks TK-101A/B. However, a certain small flow is always allowed through the collector field regardless of the exit temperature. The steam generator field warms up until the differential pressure between the steam header to the oil wells and separator (D-101) is 68 kPa (10 lb/in^2) or until the time set on KC-1A expires. The latter indicates that insolation is low and that operation of the steam generator in the preheat mode is desired. In winter months, or whenever low insolation is anticipated, the time set on KC-1A should be short so that no attempt is made to proceed to steam generation. Instead, the steam generator field is operated in the preheat mode.

5.1.2.2 Steam Generation

When the pressure differential between the steam header and D-101 is 68 kPa (10 lb/in^2), PDSL-9 starts P-102, opens valve HV-10, and closes valve HV-11. As steam is produced, valve LV-8 is controlled to maintain a constant level in the separator by preheated water from TK-101A/B. If FSL-14 detects a loss of steam flow for more than 30 minutes, the heat recovery mode of operation is started. This mode is also initiated by XSH/L-1 if the solar intensity falls below 158 w/m^2 (50 Btu/h/ft^2) for 30 minutes.

5.1.2.3 Steam Generator Field in Preheat Mode of Operation

If low levels of insolation exist or are anticipated, the preheat mode of operation is initiated. In this mode pump P-105 is started at its high speed and P-103 stopped, HV-10 is closed, HV-11 opened and P-102 started to feed 21°C (70°F) water from the feedwater treatment system. When the temperature in D-101 reaches 121°C (250°F), valve TV-38 opens and, governed by the temperature control loop TC-38, maintains a 121°C (250°F) temperature in the water that is sent from the steam generator field to the storage tanks. The level in P-101 is maintained steady by throttling LV-8. When the insolation level falls to 158 w/m^2 (50 Btu/h/ft^2), the collectors are stowed, pumps P-101, P-102 and P-105 are stopped, valves HV-11 and TV-38 are closed, and valve HV-10 is opened. The system is then shut down overnight. When the steam generator collector field is operated in the preheat mode, no heat recovery occurs.

5.1.2.4 Heat Recovery

When the transition is made from steam generation to heat recovery, P-105 is started, HV-10 is closed, and HV-11 and FV-6 are opened. P-103 is then stopped. Feedwater at 21°C (70°F) is fed to the steam generator field and water from this field is then transferred at a preset flow rate from D-101 to TK-101A/B, the flow rate being governed by the control loop FC-6. This water is cooled to 121°C (250°F) by direct mixing with water displaced from the preheat field. The flow rate of cooler water from the preheat field is controlled by valve TV-5. When the temperature of the mixed water flow falls below 115°C (240°F), TSL-5 stops pumps P-101, P-102 and P-103, closes FV-6 and HV-11, and opens HV-10. The collectors are stowed prior to stopping the pumps or whenever the insolation falls below 158 w/m^2 (50 Btu/h/ft^2), whichever occurs first. The system remains this way overnight.

5.1.2.5 Freeze Protection

If the ambient temperature falls below 0°C (32°F) when the system is not in operation, a majority vote by a series of temperature switches (TSL-12 A/B/C) will initiate the freeze protection mode of operation. The smaller pumps (P-104 and P-105 at slow speed) are started to circulate water through the field so as to prevent freezing.

5.1.2.6 Other Miscellaneous Conditions

If the levels in TK-101 A/B are high, feed valve LV-3 is closed, pump P-101 is stopped, and the collectors in the preheat field are stowed. If the steam generation field is operating in the preheat mode it too will be shut down if TK-101A/B starts to overfill.

If the levels in TK-101 A/B are very low, LSLL-39 will open valves LV-39A and HV-11 and close valves LV-39B and HV-10. This allows the steam generation field and fired boiler to continue operation using 21°C (70°F) feedwater.

If the level in D-101 goes very low, LSLL-15 will cause the collector in the steam generation field to stow, and, after an interval of 2 minutes, stop pumps P-103 or P-105. Similar action is taken if a low flow is detected by FSL-7 or, in the preheat field, by FSL-4. Switch HS-36 enables the operator to initiate the shutdown or "overnight" mode.

High wind speed (NSH-1) or operation of the demand switch HS-16 will also initiate a shutdown.

5.1.3 EQUIPMENT DESCRIPTION

In this Section, certain features of the preliminary design are discussed with particular emphasis on those that affect the safe and efficient operation of the solar thermal system.

5.1.3.1 Collectors

In the preliminary design Sandia EPT solar collectors are used. These are representative of commercially available, line-focusing parabolic trough collectors. It is assumed that these collectors are driven by dc motors powered by trickle-charged batteries; in the event of a power failure the collectors can still be stowed. Should ac motors be used to drive the collectors then a back-up generator will be required. Even so, this would not provide adequate protection in the collector field devoted to steam generation if the power failure occurs between the generator/substation and the collector.

Each collector is protected against overtemperature, and the resulting overpressure and/or degradation of the solar receiver coating, by a temperature switch that commands the collector to stow. In addition, groups of collectors are protected with safety-relief valves that discharge close to grade. The design is such that no portions o of the collector field can be isolated without such protection. The decision as to the number of such valves represents a compromise between the goal of having small numbers of collectors isolated for maintenance purposes and the avoidance of capital costs and propensity for leaks and maintenance problems associated with the large numbers of isolation and relief valves. To prevent the system from blowing down in the event of a major leak, excess flow valves are provided at the entrance and check valves at the exit to each group of collectors.

Although this preliminary design assumes that flexible hoses will be used to connect the receiver tubes with the headers, a final decision on this matter awaits the results of further study. It will be possible to vent each receiver tube of gases trapped in the system.

Though each collector will possess its own tracking controls and overtemperature protection, the instructions to unstow come from field controllers when insolation is adequate, and to stow when insolation is poor, wind speed is high, or on demand. These field controllers are governed by a master controller that interfaces with the nonsolar process controls.

5.1.3.2 The Preheat Field

To ensure an adequate flow of water through the preheat field, three steps are taken:

- A permanent bypass to HV-2 is provided.
- The flow through the field is monitored by FT-4 and alarm and shutdown of the preheat system occurs if the flow falls below some minimum value.
- The temperature of the water exiting the field is monitored and alarmed (TAH-2) if it becomes high enough to overpressure the lines or storage tanks.

5.1.3.3 Storage Tanks

To allow the use of shop-fabricated storage tanks, preheated water is stored in two identical connected tanks. The pressure in these is maintained as follows: When the tanks are filling, regulating valve PCV-19 opens and vents to the atmosphere; when emptying, water vaporizes to maintain an appropriate pressure. Should the water temperature and tank pressure fall, valve PCV-19 opens and steam enters raising both the temperature and pressure. Pressure and vacuum-relief valves are provided on each tank.

If the tanks begin to overfill, a high-level alarm will be given (LAH-3) and flow to the tank will be stopped. Should the tanks empty, both the steam generator field and the fired boiler will be fed with 21°C (70°F) feedwater and LV-39A and HV-11 will open and LV-39B and HV-10 close.

5.1.3.4 Steam Generating Collector Field

Flow through the steam-generating collector field is maintained at a set value by FV-7 when steam generation is occurring. A relief valve is provided for the flash separator together with high- and low-level alarms. Should the level fall to a very low value, the switch LSLL-15 will initiate shutdown of this collector field.

5.1.3.5 Dissolved Solids

Water quality analyzers are provided for the steam generation field. Though it is anticipated that normally no blowdown beyond that which occurs in the heat recovery mode of operation will be needed, it is possible that the dissolved solids concentration in the steam generator system might rise to such a level that insufficient dilution will occur should the water left after steam generation be fed to the fired boiler. In these circumstances, the heat recovery mode of operation might be bypassed, or blowdown allowed to take place through valve TV-38 during the day.

5.2 Thermal Performance

This section describes the performance of the solar thermal system for selected days and for an entire year. It supplements the descriptions of the system and the design basis provided in Appendix E.

The results presented here were obtained through a simulation of the system using Fresno Typical Meteorological Year (TMY) weather data. In simulating the system, two simplifying assumptions were made:

- The steam generator field was operated in the preheat mode only in "winter" - the period between November 27 and February 3. The advantages of operating in the preheat mode at other times ("summer") when low insolation is anticipated are not shown.

- Complete availability of the system is assumed at all times.

With these assumptions, the annual system performance is calculated and shown in Table 5.1. The overall efficiency of the system (the ratio of energy delivered to direct normal insolation) is 37.1 percent, the total energy delivered is 6.9 x 10^{13} J/yr (65.6 x 10^9 Btu/yr). Of this energy, only 3 percent is delivered in "winter", a period that represents 19 percent of the

Table 5.1

Performance of Solar Thermal System

Insolation	Energy 10^{12} J/yr	(10^9 BTU/yr)
Direct normal	186.2	(176.5)
Incident	162.3	(153.8)
Available	149.7	(141.9)
Collected	77.4	(73.4)
Delivered	69.2	(65.6)
Solar steam delivered	43.1	(40.9)
Solar preheat delivered	26.1	(24.7)
Header loss to atmosphere	4.8	(4.6)
Storage loss to atmosphere	0.3	(0.3)
Overnight losses	3.4	(3.0)
Parasitic power requirements	4.5	(4.1)

year (Table 5.2). This is because north-south oriented collectors perform poorly in winter and because of inclement weather. Accordingly, prolonged operation of the fired boiler without the benefit for solar energy must be expected at that time of year.

Figures 5.1 to 5.11 depict the behavior of the solar thermal system on March 25, June 12, and January 28. Figure 5.1 shows the rates at which solar energy is incident on the collectors on March 25. Three features of the curves should be noted:

- Early and late in the day, cosine losses are negligible; the direct normal and incident energies are essentially identical.

- Because of the cosine effects characteristic of north-south oriented collectors, the incident energy flux dips at noon.

- Energy collection in the preheat field is more efficient than in the steam generation collector field because of the higher operating temperature of the latter.

Figures 5.2 and 5.3 trace the temperatures at various points in the preheat and steam generation collector fields over the course of the day. Figure 5.4 shows the flow rates through the fields. The spike occurs when heat recovery is underway. In general, the volume of water in the storage tanks is expected to peak towards the end of the heat recovery phase.

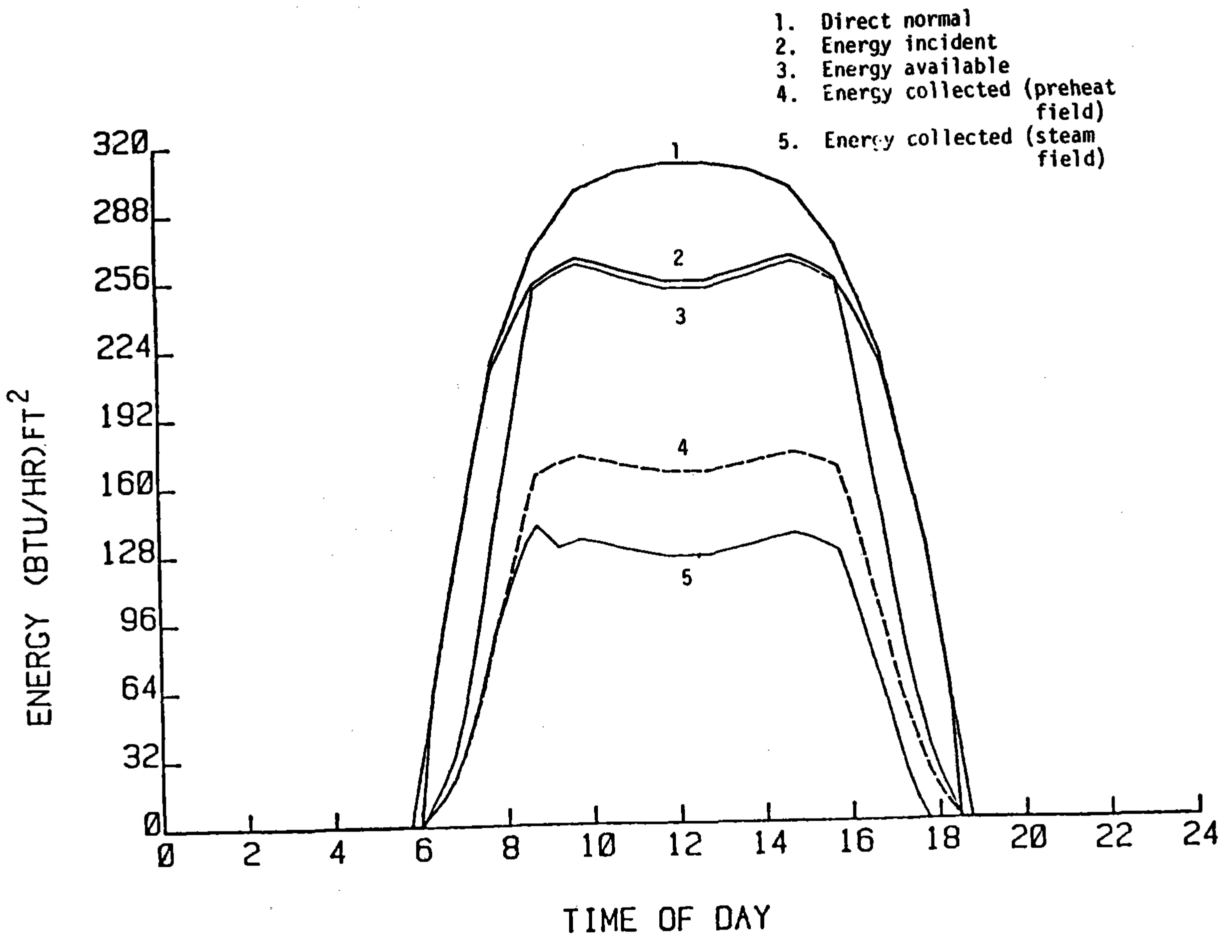
Figures 5.5 to 5.8 show the behavior of the system on June 12. On a peak summer day cosine losses are small (Figure 5.5) and the system reaches its designed operating conditions more rapidly than in March.

Figures 5.9 to 5.11 illustrate system performance on a winter day. No attempt is made to generate steam because the whole system is devoted to preheating water. Because of its larger thermal capacitance, the steam generation field takes longer to reach 121°C (250°F). In January, cosine losses and end and shading losses are greater than in March. The asymmetry in the incident energy curve results from early morning cloud cover.

On the three days chosen to illustrate the performance of the solar thermal system, there were few clouds. Should insolation be lower, other behavior would be seen:

- System start-up might not occur

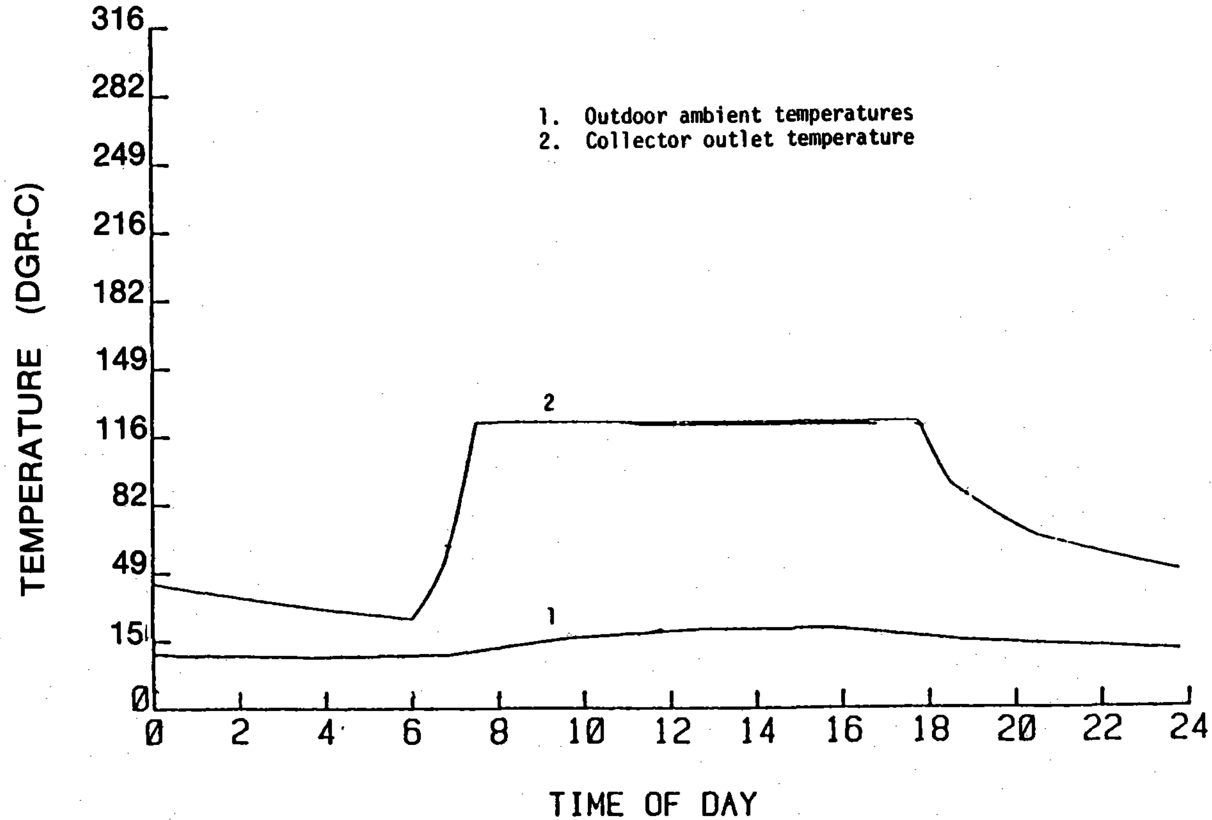
- Operating temperatures might be reached later



Note: 1 BTU/hr-ft² = 3.1525 W/m²

Energy Production on March 25

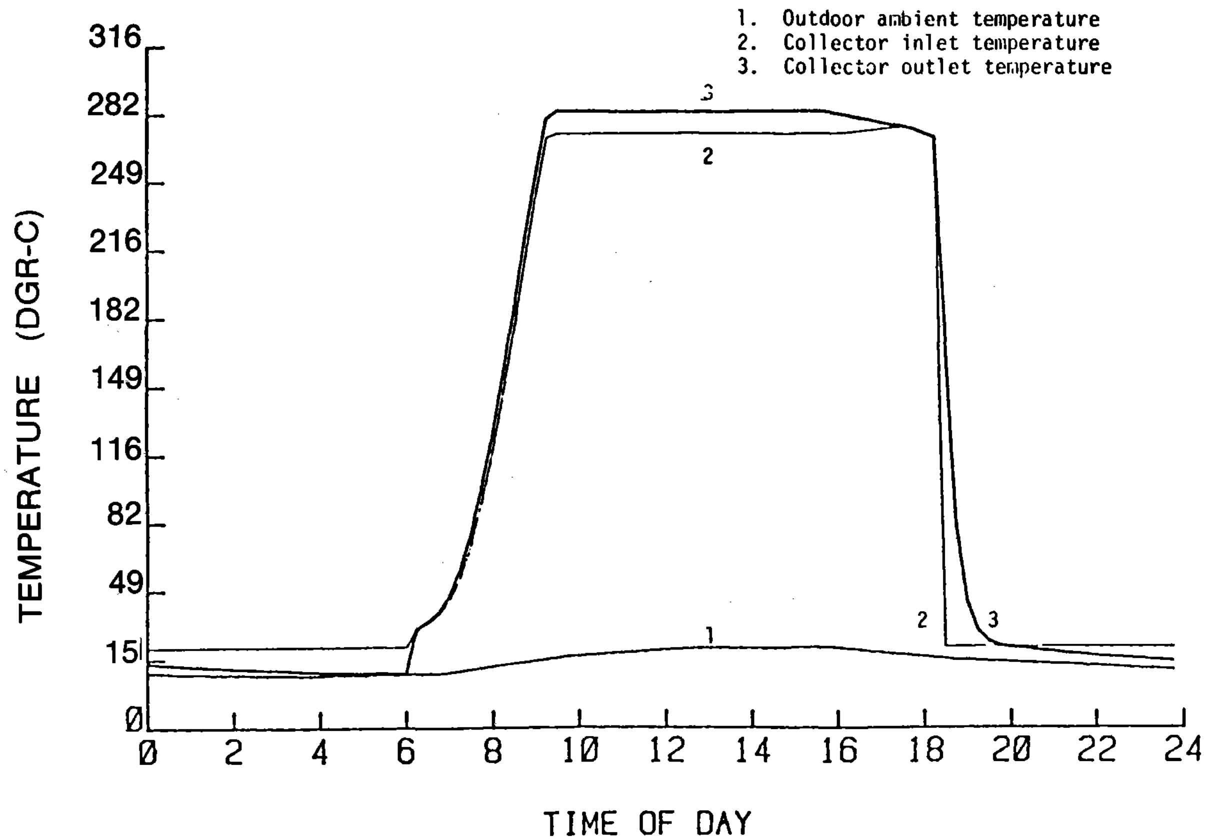
Figure 5.1



Preheat Loop Temperatures

Figure 5.2

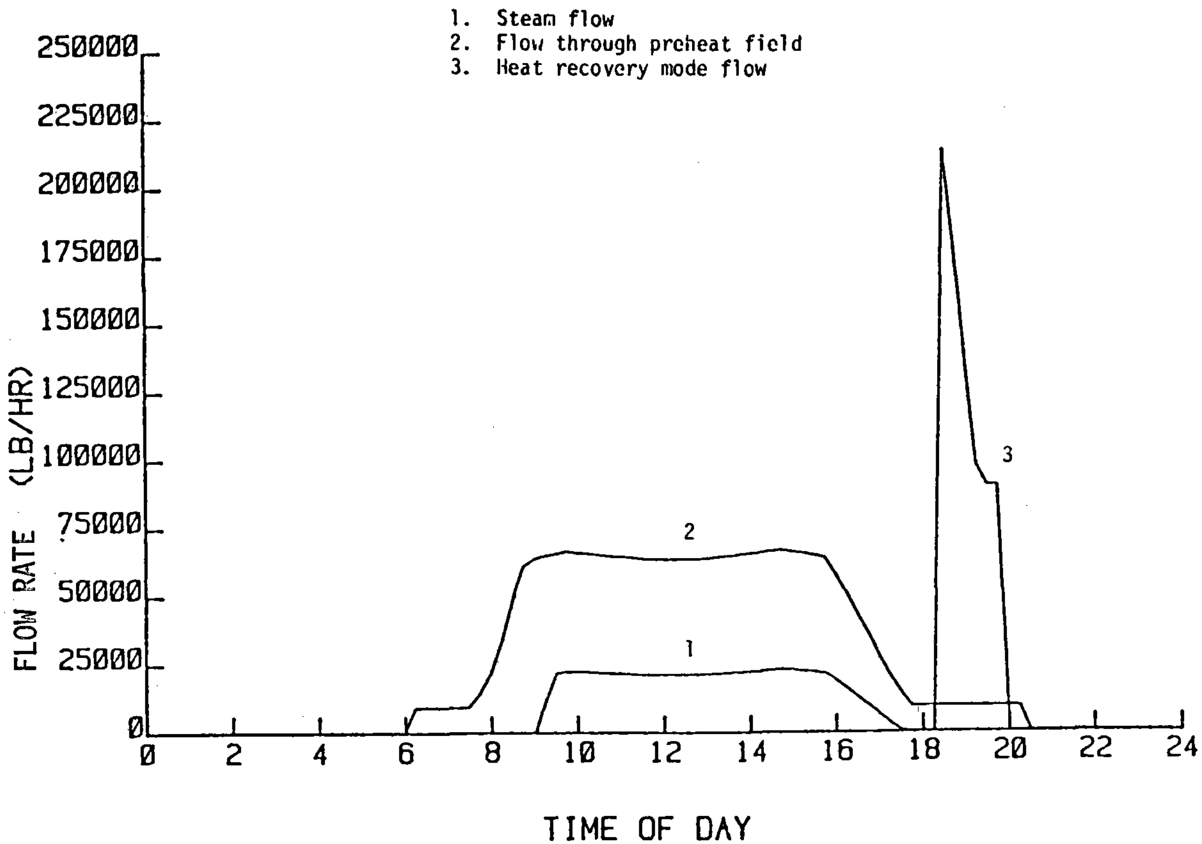
NOTE: $^{o}F = (9/5^{o}C) + 32$



Steam Loop Temperatures

Figure 5.3

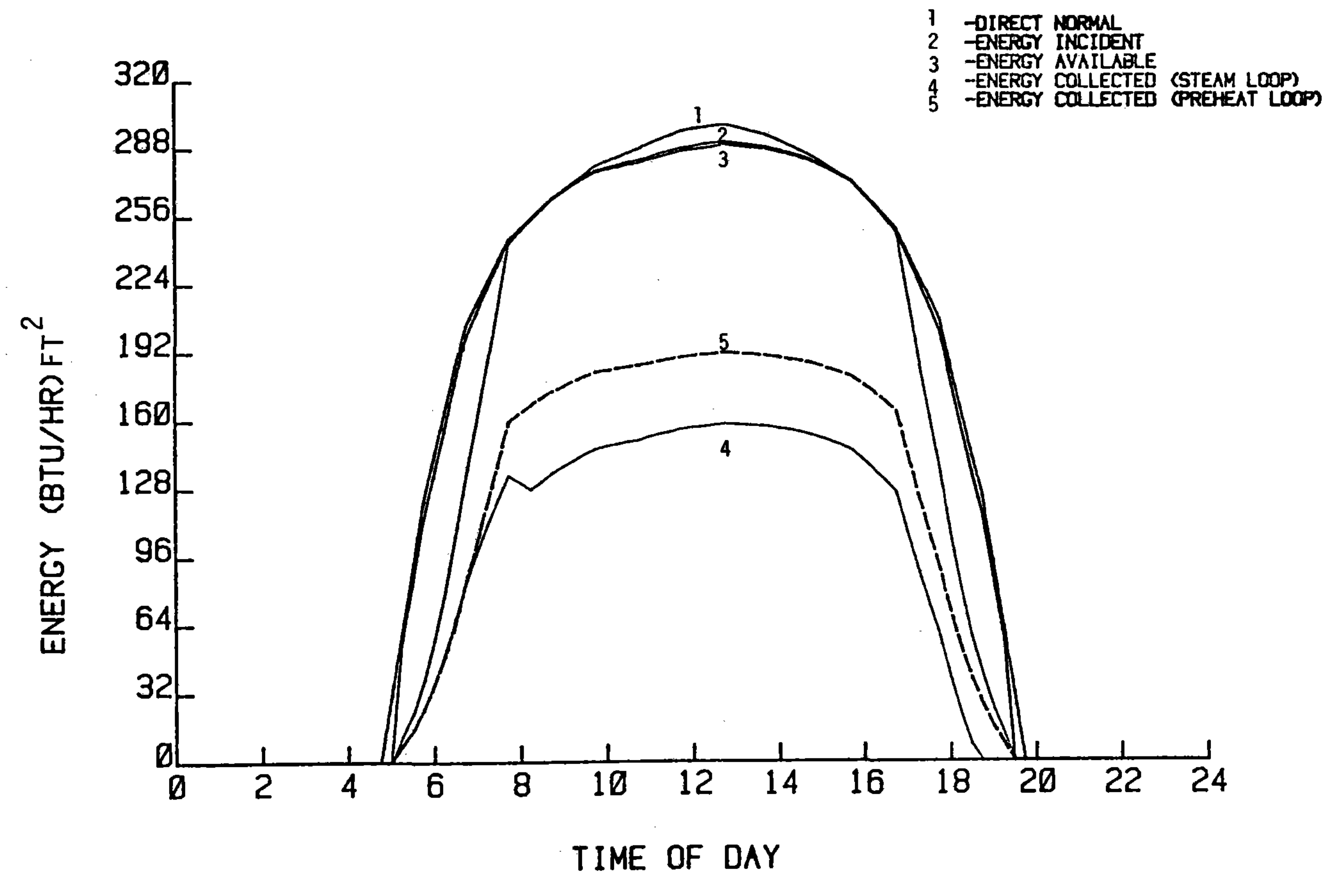
NOTE: $^{o}F = (9/5^{o}C) + 32$



Flow Rates Through Fields

Figure 5.4

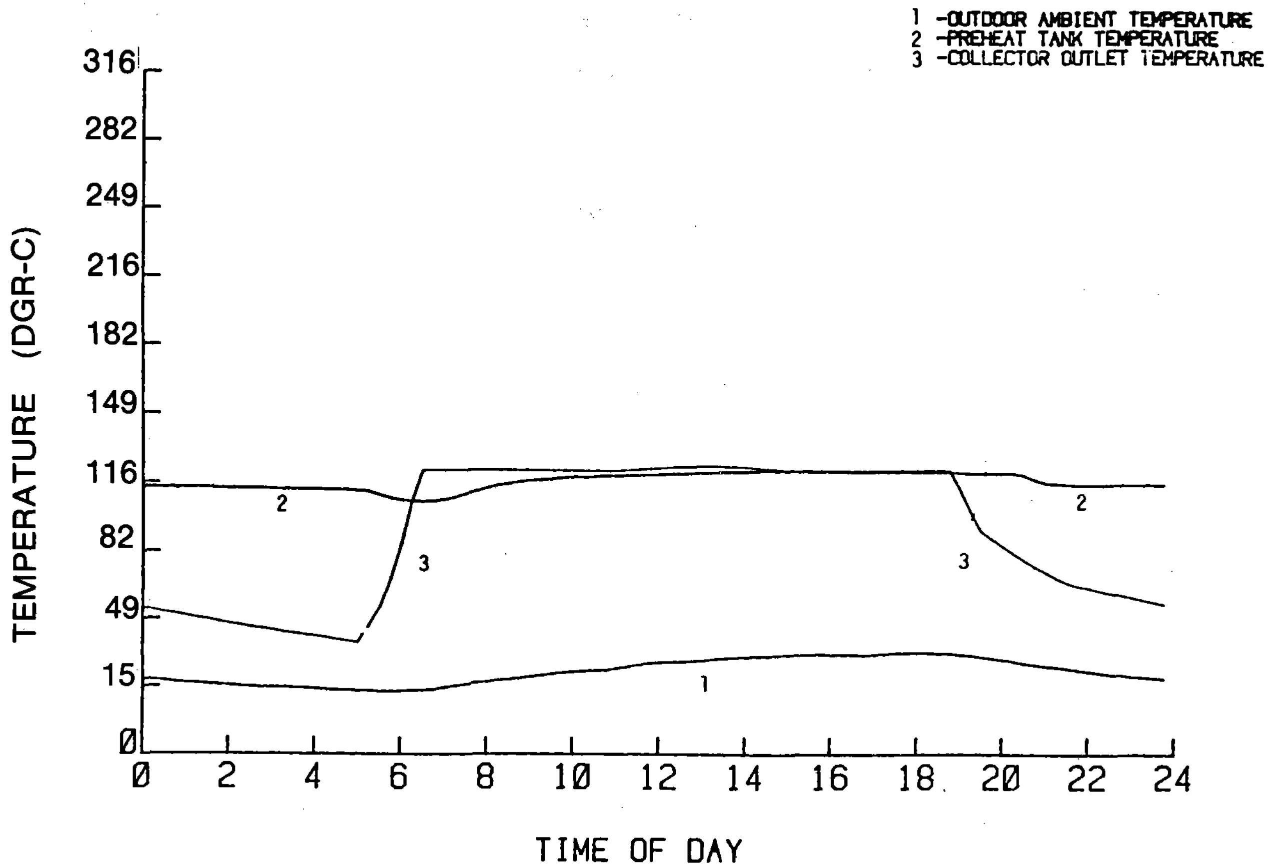
Note: 1lb/hr = .000126 kg/sec



Energy Production on June 12 (Peak Summer Day)

Figure 5.5

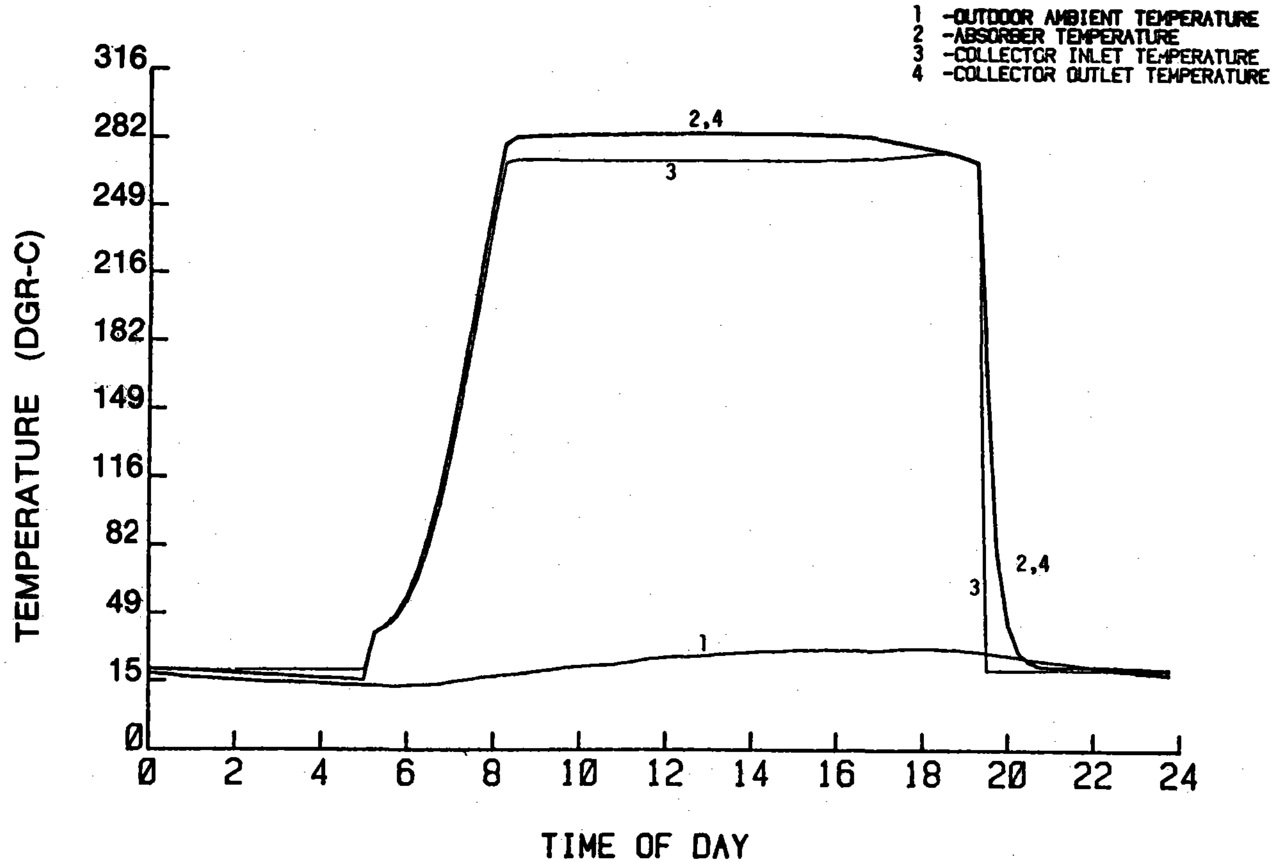
Note: 1 BTU/hr ft² = 3.1525 W/m²



System Behavior on June 12

Figure 5.6

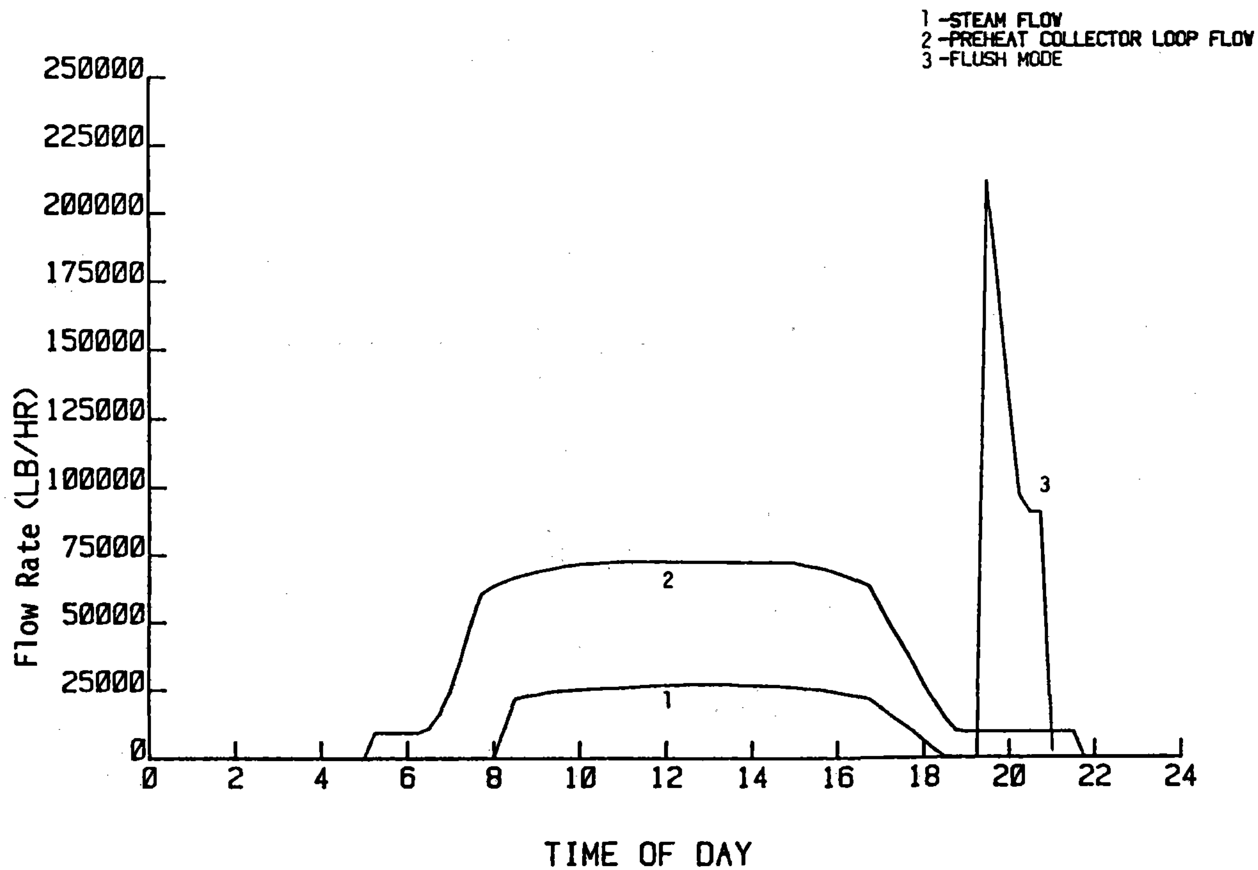
NOTE: $^{o}F = (9/5^{o}C) + 32$



Steam Loop Temperatures on June 12

Figure 5.7

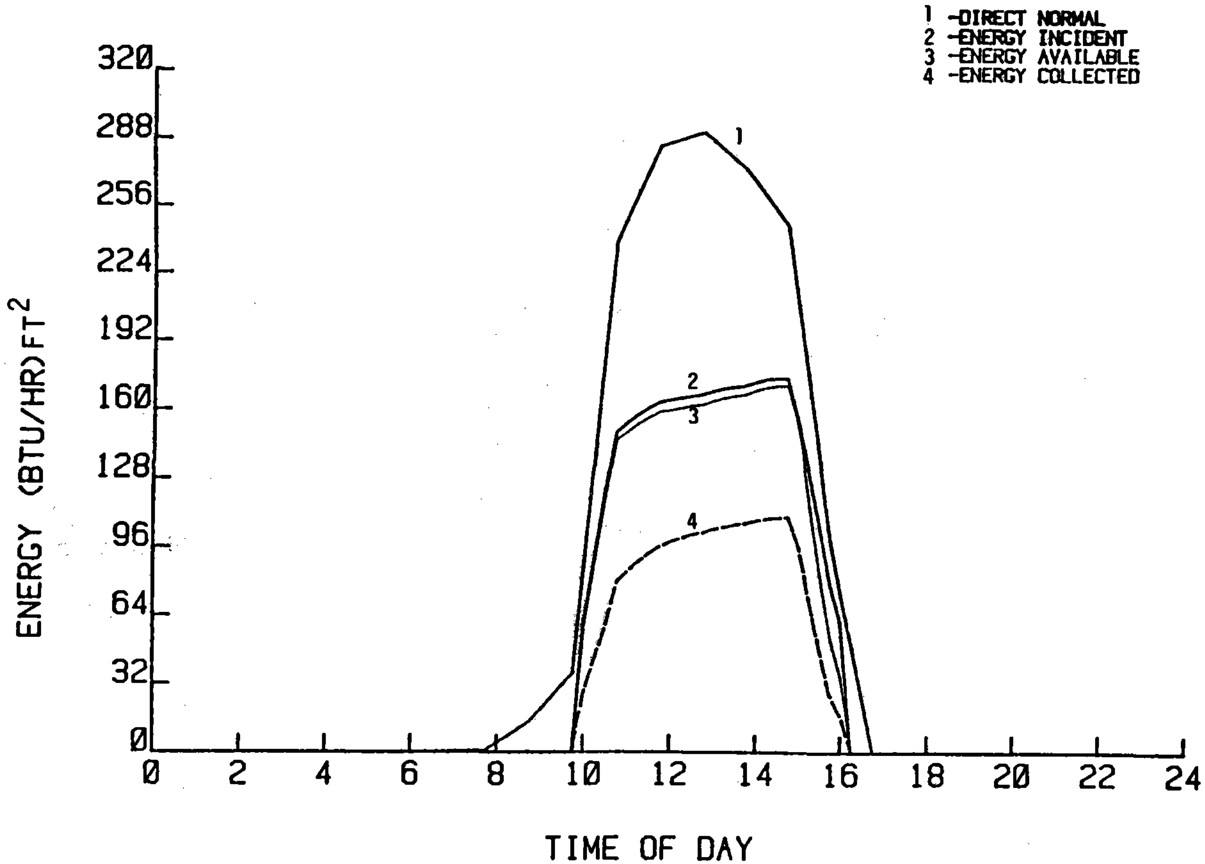
NOTE: $^{o}F = (9/5^{o}C) + 32$



Flow Rates on June 12

Figure 5.8

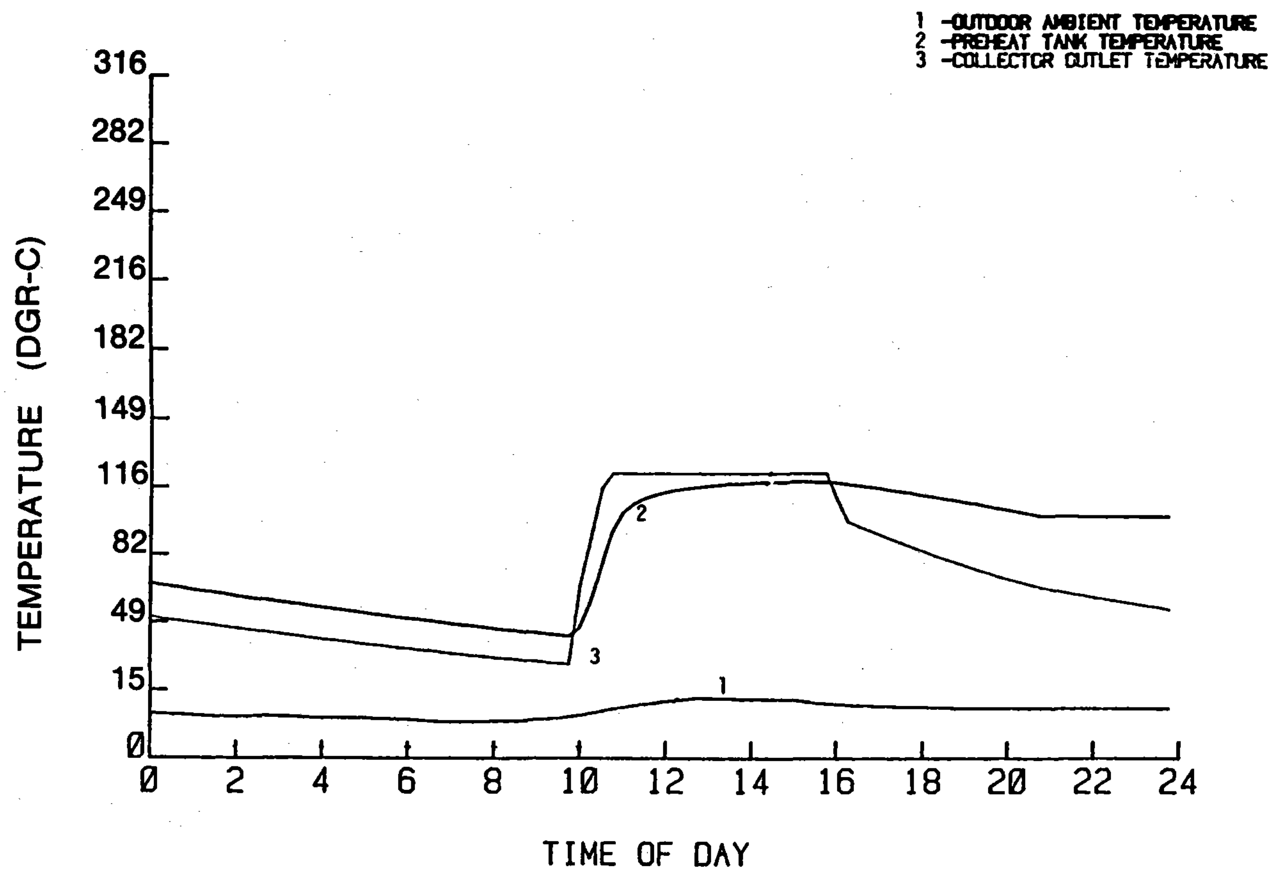
Note: 1lb/hr = .000126 kg/sec



System Behavior on January 28

Figure 5.9

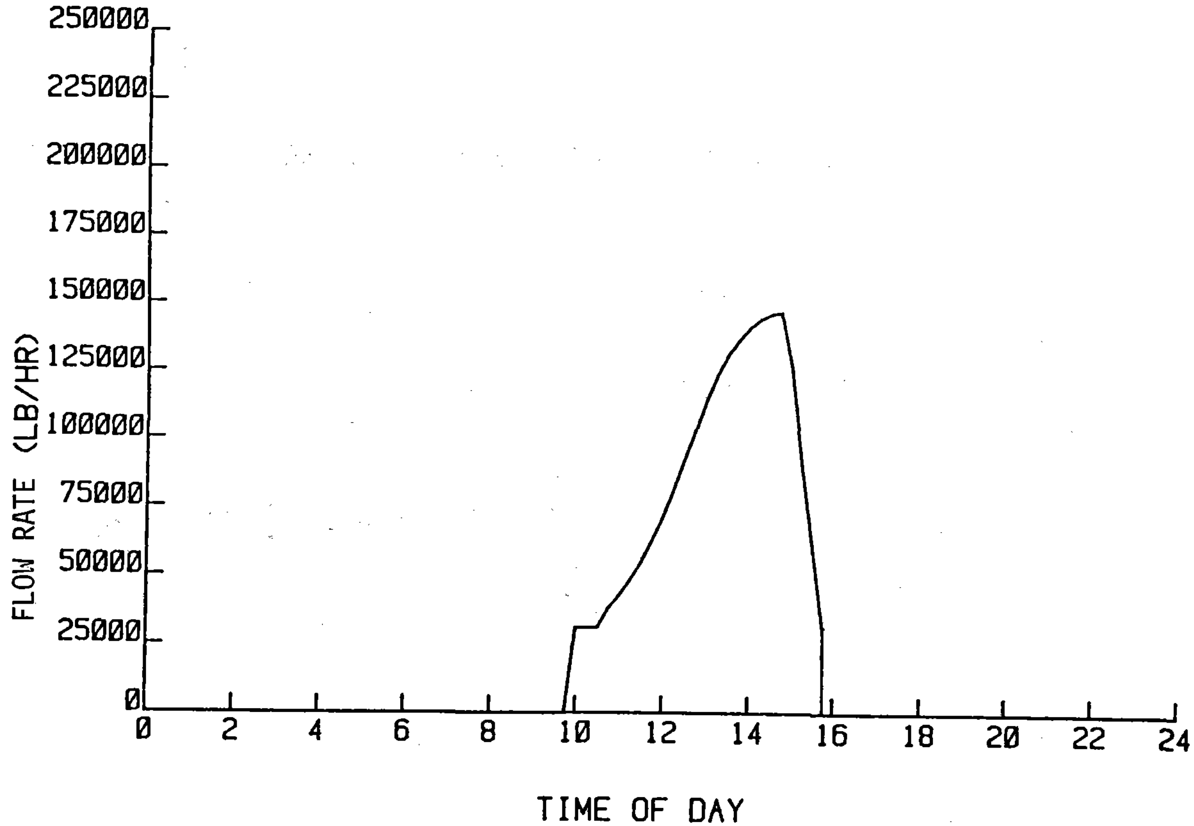
Note: 1 BTU/hr ft² = 3.1525 W/m²



System Preheat Temperatures on January 28

Figure 5.10

NOTE: $^{o}F = (9/5^{o}C) + 32$



System Flow Rates on January 28

Figure 5.11

Note: 1lb/hr = .000126 kg/sec

Table 5.2

System Performance in Summer and Winter With 3.8/M (12.5-ft) Spacing

Summer: February 4 through November 26.

Winter: November 27 through February 3.

	Total		Summer			Winter		
	10^{12}J	(10^9 BTU)	10^{12}J	(10^9 BTU)	Percent	10^{12}J	(10^9 BTU)	Percent
Energy Collected	78.9	(74.8)	75.4	(71.5)	96	3.5	(3.3)	4
Energy Delivered	69.1	(65.5)	67.0	(63.5)	97	2.2	(2.1)	3
Solar Preheated Water Delivered	29.7	(28.2)	27.5	(26.1)	93	2.2	(2.1)	7

- o The steam generation field might be instructed to operate in a preheat mode
- o The heat recovery mode of operation might be initiated if the temperature of the steam generation field exceeded 121°C (250°F).

The simulations performed account for these responses to low insolation.

5.3 System Safety

This solar thermal system poses three major potential safety hazards:

- o Visual hazards arising from concentrated solar radiation
- o The possibility of a catastrophic failure resulting in injury and equipment damage
- o Accidental releases of pressurized water and steam from valves and lines.

Many of the safeguards incorporated in the design have already been described; others are addressed in the failure modes and effects analysis performed to identify the causes and consequences of possible failures and to ensure that no problem areas remain. This section emphasizes the safeguards that protect against the occurrence of the identified major potential safety hazards.

The visual hazards associated with parabolic trough collectors occur not only when a person approaches the receiver but also when reflected radiation spills off the end of the collectors. Accordingly, the following recommendations are made:

- o Movement near the collectors should be restricted when the collectors are not stowed
- o Maintenance should take place at night where possible; collectors in the vicinity of daytime maintenance operations should remain stowed
- o A trip wire with placards should be placed 5 to 6 ft away from blocks of collectors

- A perimeter fence should be erected

- Should maintenance on an unstowed collector be absolutely necessary in daytime, shade-3 goggles should be used whenever shadows can be seen.

A more conventional hazard is the possibility of a catastrophic failure resulting in the release of water at pressures up to 6.90 x 10^6 Pa absolute (1000 lb/in^2a) and at temperatures up to 282°C (540°F) and possible shrapnel or projectile damage. Catastrophic failure can arise both from a failure of the lines and vessels under normal operating conditions and as a result of overpressure within the equipment. The likelihood of failures under normal operating conditions is low as all equipment will be designed according to the appropriate codes, hydrostatically tested, and maintained using standard industrial practices. Experience in the design and use of flexible hoses connecting the receiver tubes to the header piping is limited. Accordingly, prior to installing hoses or other connectors, tests should be performed to ensure that the fatigue life of the hose or connector is adequate under the conditions of service. It should be noted that failures which occur in hoses with an adequate radius of curvature are unlikely to be catastrophic and thus might be detected by placing a drain tube within the insulated jacket. Furthermore, should any major release occur in the collector field, excess flow and check valves will prevent the release of large volumes of water. Finally, as operations are unlikely to require the presence of many personnel, the likelihood of personnel injury in the event of a catastrophic failure is low.

Overpressure can also result in the catastrophic failure of lines and equipment. In this system, these can be caused by high temperatures or by the overfilling of storage tanks TK-101A/B or the separator vessel D-101. To guard against such occurrences, the design includes safety valves on all vessels and on lines that can be isolated. Provision is made for the automatic stowing of collectors if the receiver temperature is high and high-level alarms are located in all vessels.

A third hazard posed by this solar thermal system results from personnel exposure to water or steam discharge when relief, vent or isolation valves are opened. To guard against injury in these circumstances, all safety valves will discharge vertically downwards to a point inches above grade and air vents will discharge vertically upwards at a point 2 m (7 ft) above grade. Should collectors or piping be removed, the importance of fitting blank flanges and the performance of maintenance at night after the completion of heat recovery should be emphasized.

Line and vessel insulation is of such thickness that touching the lines or equipment should not result in injury or discomfort.

5.4 Reliability, Maintenance, and Spares

The reliability of this solar thermal system and the maintenance efforts required to sustain efficient operation are significant factors in determining the delivered cost of solar thermal energy. In this section, some anticipated reliability problems will be identified and discussed. Maintenance requirements will be assessed and sparing policies recommended.

5.4.1 UNSCHEDULED MAINTENANCE

The availability of this solar thermal system is enhanced by certain design features:

- The collector fields devoted to preheating boiler feedwater and to generating steam can be operated independently.
- Instrumentation is provided to warn of system abnormalities.
- Protective features are incorporated to prevent damage.
- The control systems allow for system operation with a minimum of operator involvement; operating personnel can monitor the system, identify problems, and perform preventive maintenance.

The reliability of the system will be diminished through component failure and operator error. The consequences and likelihood of the failures are addressed in the failure modes and effects analysis (Appendix G). All the recommendations made in the course of this analysis have been incorporated in the preliminary design. An inspection of these failure modes indicates that a total shutdown of the solar thermal system is unlikely; failures will instead result in the stowing of collectors and in the operation of the system in a less-than-optimal fashion.

Assuming failure rates typical of those found in the chemical process industry, estimates of failure rates and times to repair for the major components in the system are presented in Table 5.3. Two conclusions can be drawn from this table:

- Because of the large number of collectors installed, most of the reliability problems are expected to be caused by the collectors and their control and drive mechanisms. The collectors represent a new and relatively untried technology whereas the nonsolar portion of the system is conventional.

Table 5.3

Unscheduled Maintenance

Component	Number in System	Failure Rate (yr^{-1})	Mean Time to Repair (h)	Unscheduled Maintenance (h/yr^{-1})
Collectors, Controls, Drive Motors				
Control	504	0.12	1	60.0
Drive motor	504	0.044	4	88.0
Temperature switch	504	0.09	2	91.0
Field controller	9	0.18	1	2.0
Master controller	1	1.2	1	1.0
Flexible hose	1008	0.005	(1) 8	40 0
Subtotal				282.0
Remainder of System				
Hand switch	2	0.25	4	2.00
Pump	5	1.2	8	48.00
Pump motor	5	0.044	8	1.76
Alarm	6	0.2	2	2.40
Level, temperature, and flow switch	14	0.22	2	6.16
Level transmitter	2	0.22	2	0.88
Water hardness meter	2	10.9	2	43.60
Level/flow recorder	2	0.22	2	0.88
Level gage	2	0.027	2	0.108
Flow transmitter	3	0.49	2	2.94
Temperature transmitter	3	0.41	2	2.46
Differential pressure transmitter	2	0.76	2	3.04
Multipoint temperature recorder	7	0.52	2	7.28
Solenoid valve	16	0.44	2	14.08
Controller	5	0.39	2	3.90
Pressure indicator	5	0.026	2	0.26
Control valve	11	0.60	4	26.40
Open-close valve	2	0.13	4	1.04

Table 5.3

Unscheduled Maintenance (Cont.)

Component	Number in System	Failure Rate (yr^{-1})	Mean Time to Repair (h)	Unscheduled Maintenance (h/yr^{-1})
Isolation valve	30	0.2	4	24.00
Drain valve	24	0.2	4	19.20
Safety valve	21	0.022	4	1.85
Limit switches and light	5	0.5	2	5.0
Weld/pipe		0.28	4	1.12
Subtotal (remainder of system)				218
Total Unscheduled Maintenance				495

(1) The failure rate listed here assumes successful conclusion of the flexible hose test and development program (Appendix D). If a higher failure were determined by the tests, then maintenance manpower would increase accordingly.

- Unless higher-than-anticipated failure rates are found, the repair of failures will involve far less effort than routine preventive maintenance.

The second conclusion is drawn from a comparison of the unscheduled maintenance effort required (500 man-hours/yr) with the scheduled maintenance required (6830 man-hours/yr).

5.4.2 ROUTINE MAINTENANCE

The prime focus of the maintenance procedures adopted for the collectors is to maintain high collector efficiencies. These may be impaired by several factors:

- A fall in reflectivity of the collector mirror surface
- Filling of the glass tube surrounding the receiver with dust
- Degradation of the receiver coating
- Movement of the receiver tube out of focus.

The reflectivity of the collector mirror surface falls if the surface is damaged by impact or abrasion, by weathering, or by a covering of dust. Impact, abrasion, and weathering damage can be minimized by stowing the collectors should dust storms, hail, or other inclement weather conditions occur.

The collector reflective surfaces will be cleaned by washing with a biodegradable detergent and then rinsing with water. To avoid damage to the surface, the procedures recommended by the manufacturer should be followed. It is anticipated that cleaning will be performed using hand-held sprays fed from tanks mounted on trucks. This cleaning is expected to be required 12 times per year and to take 1500 man-hours per year.

Unless a good seal is provided, dust will enter the glass envelope surrounding the receiver tube and periodic cleaning of the envelope will be required. As this task could take from 3000 to 20,000 man-hours of effort per year depending upon the design of the glass envelope and maintenance procedure adopted, achieving as good a seal as possible is essential. This will diminish the effort required to clean out the dust and prevent the entrance of excessive amounts of moisture into the glass envelope. Moisture has been found to cause the degradation of the black chrome receiver coating.

Another possible cause of this degradation is the occurrence of a temperature excursion in the receiver tube. Particular attention has been paid to preventing this in the design and instrumentation of the system.

The controls and drive mechanisms are estimated to require 1200 man-hours per year of maintenance for the lubrication of chains, seals, and drives and to artifically create "out-of-limits" signals to check safety response.

Defocusing of the receiver tube results from failures in the tracking controls and from distortions in the collector. The magnitude of the former problem is addressed in Table 5.3, the latter will depend upon the cause and magnitude of the distortions introduced.

The scheduled maintenance effort required is shown in Table 5.4. The total maintenance effort, both scheduled and unscheduled, is estimated to be 7330 manhours. This estimate relates to the maintenance times required after an initial 1-year period of performance.

5.4.3 SPARING POLICY

As maintenance may be performed on this solar thermal system overnight or whenever insolation is low, the need for installed spares is lessened. However, warehouse spares for key equipment and parts will be required. Selection of these key items should be based on the following considerations:

- o Ease of maintenance
- o Criticality of the item to system operation
- o Cost of the item.

We therefore recommend that a complete spare of an item of mechanical equipment be placed in the warehouse unless its cost is high, it is difficult to repair in place, or it is subject to rapid wear. The wearing parts of instruments and valves should also be stored. For the solar thermal system we recommend the following spares:

5.4.3.1 Pumps

A spare impeller, wear rings, bearings, and shaft seal should be provided for all the pumps. The pumps specified permit easy repair while in place and are either in light duty service (P-101, P-104, P-105) or of proven high quality and reliability.

Table 5.4

Routine Maintenance (Man-hours/yr)

ITEM	Required Effort
Cleaning of collector mirrors	1500
Cleaning of glass tubes surrounding receivers	3000+
Drive motors	
Controls (solar system)	1200
Pumps	40
Valves	240
Instruments	450
Insulation	400
TOTAL	6830

5.4.3.2 Control Valves

A complete warehouse spare plus spare seats, seals, and wearing items are recommended for those valves in flashing service (FV-6, FV-7, and TV-38). Spare seats, seals, and wearing items are recommended for valves in nonflashing service (LV-3, TV-2, TV-5, LV-8, HV-1D, HV-11, TV-12, LV-39A, and LV-39B).

5.4.3.3 Tracking Controls

Several spare boards for the local and field controllers and sets of sensors should be maintained.

5.5 Environmental Considerations

Effects on the environment of solar and oil fired steam generators are very different and are best discussed separately. The environmental effects of the fired steam generator portion of a hybrid solar/thermal system will be the same as any new fired generator. However, while the combination of solar and fired steam generation does not by itself reduce the amount of pollutants emitted per barrel of oil burned, it reduces emissions per million Btu total input to the system. When the combination of solar and fired steam generation is considered a single energy source, the amount of pollutants emitted per million Btu input is 25% less than from fired steam generators.

This section discusses the environmental factors associated with the hybrid unit at the Edison site. These factors include glare from the solar collectors (occupational aspects of these factors were discussed in Section 5.3), disposal of wastes, land utilization and air quality.

5.5.1 GLARE FROM COLLECTORS

Glare which might temporarily flashblind an airplane pilot or a motorist on a nearby highway is less of a problem with parabolic collectors than central tower systems. This is due to the fact that, except when very close to the collector, the reflection will be less than the intensity of the sun viewed directly. This glare can be avoided by looking away from the source. Only if it were necessary to look directly at the reflected light to operate an airplane or car would the collectors present a hazard. It is difficult to conceive of a situation which would require this.

Orientation of the solar collectors presents no opportunity for reflection of light toward Hermosa Road. Reflection of light toward Tejon Highway late in the afternoon is possible. However, this light would be from the east side of the road and not directly into the eyes of traffic from either direction. Glare from the collector field even during periods when collectors are defocused does not present a serious hazard to aircraft or ground vehicles. The opportunity for reflected light to reach nearby roads can be eliminated at low cost if this proves necessary. Since the axis of reflectors is six feet above grade and the terrain is level, it will be possible to screen the collectors from Tejon Highway with a hedge or fence if this is necessary.

5.5.2 LIQUID AND SOLID WASTES

Water required for solar and fired steam generation, and also for scrubbing of sulfur oxides, is obtained from a water well. This water is softened by treatment in ion exchange beds which remove calcium and magnesium carbonates, and smaller amounts of chlorides, sulfates, and nitrates. Regeneration of the ion exchange beds produces a concentrated solution of these ions.

5.5.3 LAND USE EFFECTS

Edison Field is on a flat alluvial plain. Agricultural and oil production operations have been carried out in the area for nearly 50 years. Recently, potatoes have been grown on irrigated land around the oil producing wells. The annual value of this crop approximates $1,850 per acre.

5.5.4. AIR QUALITY EFFECTS

Oil fired steam generating equipment is a source of sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide and particulates. Ambient air quality standards have been set for all of the above. When measurements show that one or more of the pollutants will exceed the standard then it is up to the local district to devise a plan to remain in compliance. This is usually done by setting emission standards and such standards now exist for sulfur dioxide, nitrogen oxides and particulates. Emission standards set the maximum level of a pollutant per unit of capacity and now exist in Kern County for sulfur dioxide, nitrogen oxides and particulates. The maximum emission level is determined by the capabilities of available technology i.e. scrubber for SO_2 and improved burners for NO_x. If emission standards are insufficient in maintaining the level of a given pollutant below the ambient standard then the number of sources will be controlled.

The reductions in emissions attributed to a solar hybrid system is in direct proportion to the fraction of heat supplied by solar. Resulting air quality improvements in the Bakersfield area resulting from a solar installation at Edison will be insignificant because the Edison operation contributes such a small fraction of the pollutants in the area.

FOR ADDITIONAL INFORMATION See Appendix K.

5.6 Permits Required

Permits for the proposed STEOR system at Edison appear to be straightforward. An environmental impact statement is not required provided there is no U.S. Government involvement in funding, providing land or in any other permits. The California Air Resources Board does require permits for the installation and operation of the oil fired boiler and a local construction permit will be required for facilities erected at the site.

6. COST ESTIMATE FOR STEOR AT EDISON FIELD

A preliminary cost estimate was made for the Edison STEOR 22,830 m^2 (245,655 sq. ft.) flash separator/preheat plus storage system. The input for this estimate is the Design Basis (Appendix E). Further information on what is included and excluded is contained in Appendix H. The estimating procedure is a standard technique developed by Foster Wheeler and is accurate to ± 10%. All dollars are for March 1980.

No attempt is made in this section to analyze the economics. This is done in the Market Study (Section 8). However, to facilitate this subsequent analysis the costs have been allocated between the preheat section and the flash vaporization section of the 22,830 m^2 (245,655 ft^2) system. They have been further broken down so that the cost of major subsystems can be seen.

Investments reported in Tables 6.1, 6.2, 6.3, and 6.4 are not directly comparable to those shown in Section 1, Table 1.7 Column 1 and in Volume III due to differences in basis and contingency used by Foster Wheeler and Exxon. This comment on differences pertains directly to the 9,636 m^2 (103,680 ft^2) preheat-only system cost estimates, for which Table 6.6 provides a reconciliation of Exxon and Foster Wheeler estimates.

TABLE 6.1

SUMMARY OF SYSTEM COST

Item	Cost ($) Feedwater Preheat With Storage System	Cost ($) Flash-Separator/ Preheat With Storage System
Direct Materials	2,007,300	6,570,700
Subcontracts	459,750	1,253,050
Direct Labor	943,620	2,438,540
Indirect Materials, Tools, Labor, Supervision, and Payroll Burden	1,462,610	3,779,700
Detailed Design, Procurement, and Other Home Office Costs	364,770	1,276,700
Miscellaneous	22,228	77,800
TOTAL	5,260,278	15,396,490

NOTES

1. The estimates for both the feedwater preheat with storage system and the flash-separator/preheat with storage system include a building and the steam distribution lines necessitated by the fixing of the steam generators.

2. The costs of fencing, culverts, and ground coverage are assumed to be proportional to the perimeter or area of the field.

3. The design, procurement, and other home office costs, and miscellaneous costs are assumed to be proportional to the size of the collector field.

4. The estimate does not include the cost of a data acquisition system.

TABLE 6.2

FEEDWATER PREHEAT WITH STORAGE SYSTEM-EQUIPMENT

Items	Materials ($)	Subcontract ($)	Direct Labor Including Productivity	
			Man-hours	($)
Collectors	1,431,800		19,010	260,630
Storage Tanks	79,200		180	2,740
Pumps	3,500		80	1,060
Mixer	2,100		10	130
Instrument Air	2,600		30	400
Sub-Total Equipment	1,519,200		19,310	264,960
Sub-Total Other Materials	488,100	459,750	44,460	678,660
Totals	2,007,300	459,750	63,770	943,620

TABLE 6.3

FEEDWATER PREHEAT WITH STORAGE SYSTEM--OTHER MATERIALS SUMMARY

Items	Materials ($)	Subcontract ($)	Direct Labor Including Productivity Man-hours	Direct Labor Including Productivity ($)
Earthwork, building, fencing, and planting		75,500		
Collector Foundations		222,800		
Structural Steel	70,400		1,440	20,740
Piping	179,300		16,080	244,420
Instruments	135,800		5,910	90,620
Electrical	101,100		19,890	305,510
Insulation				
Pipe		113,400		
Equipment		27,200		
Instrumentation		3,700		
Painting		17,150		
Testing	1,500		1,140	17,370
Totals	488,100	459,750	44,460	678,660

TABLE 6.4

FLASH-SEPARATOR/FEEDWATER PREHEAT WITH STORAGE SYSTEM--EQUIPMENT

Items	Materials ($)	Subcontract ($)	Direct Labor Including Productivity	
			Man-hours	($)
Collectors	5,056,100		26,530	912,130
Flash-separator Drum	24,200		40	610
Storage Tanks	79,200		180	2,740
Pumps	67,300		290	3,860
Instrument Air	2,600		30	400
Mixer	2,100		10	130
Sub-total Equipment	5,231,500		27,080	919,870
Sub-total Other Materials	1,339,200	1,253,050	99,490	1,518,670
Totals	6,570,700	1,253,050	126,570	2,438,540

TABLE 6.5

FLASH-SEPARATOR/FEEDWATER PREHEAT WITH STORAGE SYSTEM--OTHER MATERIALS SUMMARY

Items	Materials ($)	Subcontract ($)	Direct Labor Including Productivity	
			Man-hours	($)
Earthwork building, fencing, and planting		197,600		
Collector Foundations		638,000		
Structural Steel	206,800		3,970	57,170
Piping	464,000		30,210	459,200
Instruments	495,000		17,120	262,370
Electrical	170,900		45,940	705,640
Insulation				
- pipe		323,500		
- equipment		28,400		
- instruments		12,900		
Painting		52,650		
Testing	2,500		2,250	34,290
TOTALS	1,339,200	1,253,050	99,490	1,518,670

TABLE 6.6

ADJUSTMENTS TO FOSTER WHEELER COST ESTIMATE FOR EXXON PROJECT BASIS

Item	Foster Wheeler Costs From Table 6.1 M$ (1)	Adjusted To Exxon Basis M$ (2)
Direct Materials	2.0	2.5
Subcontracts	0.5	0.6
Direct Labor	0.9	1.1
Indirects	1.5	1.8
Design & Procurement	0.4	0.5
	5.3	6.5 (4)
	Escalation (3)	0.7
	Exxon Eng. Charges	0.3
	Contingency	1.4
		8.9

Notes

(1) 70,187 ft^2 of collectors located on field, includes steam distribution
(2) 103,680 ft^2 of collectors located off field, excludes steam distribution
(3) From March 1980 to December 1980
(4) This subtotal is a final update which is $0.1 million greater than the estimate used in section 8.5.2.4.

7. DEVELOPMENT PLAN

A conceptual development and test plan for a preliminary design to use solar heat to preheat water, and generate steam is presented in this section. The plan covers detailed design, construction and operation of a 22,822 m^2 (245,655 ft^2) flash separator preheat plus storage system. Costs for the design and construction phases were presented in Section 6. Details on project management are contained in Volume III of this report.

7.1 Design And Construction

Foster Wheeler Development Corporation has made a preliminary estimate of the design and construction schedule based on previous projects for Exxon and taking into account the critical completion date needed to take full advantage of Tertiary Incentive Revenue. Figure 7.1 summarizes this estimate in terms of elapsed time, percentage of total investment which is committed and periods during which major activities occur.

It can be seen that a total of 21 months is required to complete the project. Therefore, if the project originated in July of 1980 it would not be completed until March of 1982 i.e. six months after the decontrol of all domestic oil. This means that (without use of prepayment provisions) some 20% of the investment would not be subject to recoupment by Tertiary Incentive Revenues. However, this estimate was based on the most conservative (6 months) of the lead time given by the three major trough collector vendors. If no lead time is required then the project could be completed by October 1981 without need for prepayment. Scheduling and expenditures are discussed in more detail in Volume II of this report.

7.2 DATA COLLECTION, ANALYSIS, DISSEMINATION

The technical and economic feasibility of a Solar Thermal Enhanced Oil Recovery (STEOR) project at Edison would be based on an analysis of performance and cost data generated by the proposed project. In this section, the nature and amount of performance and cost data to be generated by STEOR is described in detail. Section 7.2.1 describes the parameters which would be measured and recorded from all STEOR subsystems. A description and schedule of all subsystem and system level tests which were planned to occur during the two year phase IV period is given in section 7.2.2. Section 7.2.3 details the methods of collecting, analyzing and reporting STEOR data including a description and cost estimate of the site data acquisition system.

7.2.1 DATA REQUIREMENTS

In this section the type and amount of data which the STEOR program would produce are identified and the means of acquiring the data is delineated. Important reference documents relating to this task include "Data Acquisition and Analysis Guidelines for IPH Demonstration Projects (Ref. 1), "Thermal Data Requirements and Performance Evaluation Procedures for the National Solar Heating and Cooling Demonstration Program (Ref. 2) and Instrumentation Installation Guidelines (Ref. 3). The primary objective of this task would be to provide essential data on the performance, operation and costs of the STEOR project in a cost effective, reliable and timely manner.

This section describes the three primary types of STEOR data to be acquired: Performance, Operational and Economic. For each type of data a description of what is to be measured and how it would be measured is provided.

7.2.1.1 Performance Data

Solar Subsystem

The following paragraphs describe the solar subsystem performance parameters to be measured and the methods of acquiring performance data. In a general sense performance of the solar subsystem refers to the quantities of energy which are incident upon, converted by, and delivered from, the solar energy subsystem as a function of time. The solar subsystem includes preheat storage tank, flash separator and the fluid distribution network per drawing numbers 60035-2-50-101 (Process Flow Diagram) and 60035-1-50-1 (Engineering Flow Diagram). These drawings are found in Appendix E.

The basic approach to performance measurement is to measure energy balances at several levels in the solar subsystem in order to determine the location and quantity of energy losses. In this way, the performance of the various components of the solar subsystem will be monitored as well as the net energy delivered by the solar subsystem to the fossil boiler.

The parameters which will be measured in the STEOR solar subsystem include the following:

A) Net total energy delivered by the solar field
B) Net energy delivered as hot water to the fossil boiler
C) Net energy delivered as steam to the steam distribution line
D) Energy delivered to the boiler feedwater storage tank (TK101)
E) Energy output from the preheat collector field (SCP101-244)
F) Energy output from each of three preheat collector groups (SEP 101 thru 148, 149 thru 196, and 197 thru 244)

G) Energy output from each of six boiler collector groups (60 modules in each group per drawing 60035-1-50-1)

H) Energy output from three preheat collector modules and six boiler collector modules

I) Collector array thermal efficiency determined on a daily and monthly basis from measurements made in A), B) and C) above

J) Parasitic energy consumption of solar system pumps and collector drive motors

K) Operating temperatures and pressures at preheat and boiler fields

L) Environmental parameters including total insolation, direct normal insolation, ambient temperature, wind velocity, relative humidity

All of the above solar subsystem parameters would be measured automatically by means of sensors linked into the site data acquisition system (SDAS). The SDAS is described in detail in Section 7.2.3. Table 7-1 shows relevant information concerning the number, type, location, measured parameters, sampling rate and energy balance equations of the sensors required to measure parameters A through L above.

This table lists the sensors needed to measure the various energy flows in the solar subsystem which includes the preheat and boiler collector field, the thermal storage tank and the environmental parameters. These sensors would be used to measure instantaneous and daily integrated energy flows and efficiencies at the collector module, group, field and subsystem level. In addition, any long term changes in performance would be measured and the comparison of energy flows from similar collector groups would facilitate troubleshooting by permitting ongoing comparisons among physically similar collector groups. The location of the sensors listed in Table 7-1 is given in the sensor layout diagram (figure 7-2).

Conventional Boiler

The conventional oil fired boiler (PG 101) is assumed to be a Struthers Thermo flood OH25 rated at 7.33MW (25 MBTU/HR). It is currently fitted with instrumentation to record feedwater and fuel oil consumption. In order to measure the boiler subsystem performance in the same manner as the solar subsystem, the boiler would be instrumented with sensors to measure inlet water and fuel flowrates and temperature and outlet steam conditions. The sensors would be tied into the site data acquisition system for automatic recording and processing and the existing flow recorders would serve as a backup. The sensor details and energy balance equations for the conventional boiler subsystem are also shown in Table 7-1 and the sensor locations are shown in the sensor layout diagram (of figure 7-2). As indicated in the table and the drawing, energy balances would be calculated for the boiler subsystem to determine net energy output, fuel consumption and instantaneous and integrated boiler thermal efficiency. Boiler performance would be monitored before and after integration with the solar subsystem to determine any impact of the solar subsystem at the operation of the conventional boiler. A definition of all testing is given in paragraph 7.2.2.

<u>Integrated System Performance Data</u>

The data on detailed performance of the various STEOR subsystems would be combined to give performance data for the following overall system parameters which would be reported on a monthly basis:

- o Oil, Water Production Rate
- o Solar steam, solar hot water delivered to steamlines and boiler
- o Steam produced by boiler

7.2.1.2 Operational and Maintenance Data

A log book would be kept by the STEOR system operator to record STEOR operational and maintenance events. The following information would be entered manually:

- o Nature and duration (man-hours) and materials costs of regularly scheduled STEOR maintenance e.g. collector washing, boiler cleaning, steam line relocation
- o Nature and duration of unscheduled maintenance or operational 'events' e.g. solar control malfunction, steam or water leaks, boiler, SDAS malfunction
- o Brief narrative of weather conditions
- o Description of mode of operation of solar subsystem e.g. preheat only, preheat and steam, freeze protection, stow

Based on this data, the following system availability information would be calculated on a monthly basis:

- o Number of hours of demand for steam
- o Number of hours of operation of conventional boiler
- o Number of hours of operation of solar subsystem

In addition to reporting system and subsystem availability, the maintenance logs would be used to determine, on a monthly basis, the total costs of operating and maintaining the STEOR system.

7.2.2 TEST DEFINITION AND SCHEDULE

7.2.2.1 Subsystem Performance Testing

A number of tests are scheduled to determine the performance and operating characteristics of the solar and conventional boiler subsystems. The approach to subsystem testing is to isolate various components in the STEOR field and measure that components' operating characteristics over a range of operating parameters prior to proceeding to normal operations of the integrated STEOR field. A performance baseline would be established for the various components beginning with the smallest solar component (a single group of collectors) and gradually adding components until the entire STEOR is ready for system performance testing.

These tests are designed to accomplish the following:

- o Determine component performance under carefully controlled test conditions
- o Quantize subsystem performance as a function of the number of operating components
- o Provide operator training and additional system checkout by gradually moving from component to system operation.

The following paragraphs describe the various subsystem performance tests, the duration of the tests and the expected output of each test. A subsystem testing schedule is given in Table 7-2.

Conventional Boiler Subsystem

Prior to integrating the solar and conventional boiler subsystems, the boiler would be tested to establish a performance baseline under normal field conditions. Performance means a measurement of the boiler energy balances using the sensors and equations shown in Table 7-1. The boiler energy balances would be recorded for three boiler thermal outputs:

This test is scheduled to last 30 days with 20 days for normal thermal output and 5 days each for high and low output conditions. This test would provide boiler performance data under actual steam operations.

Solar Energy Subsystems

Preheat Collector Field

After integrating the solar subsystem with the conventional boiler, a series of performance tests would be conducted on various components of the solar subsystem. The first preheat collector test would be a performance test of collector group SCP 101 through 148 (refer to drawing 60035-1-50-1). The other two collector preheat groups would not be operating during this test. The test would consist of adjusting the inlet flow rate to this collector group to maintain the following outlet temperatures 38°C, 93°C, 121°C, 149°C (100°F, 200°F, 250°F and 300°F). A minimum of one day of data under good insolation conditions (direct normal insolation (I001) greater than 694 W/M^2 (220 Btu/hr. /ft^2) for five hours) would be taken at each of the four outlet temperatures. This test would establish collector energy gain and efficiency as a function of operating temperature and flow rate. This identical test would be repeated for collector groups SCP 149 through 196 and SCP 197 through 244. Finally, the entire solar preheat field (SCP 101 through 244) would be tested at all four outlet temperatures, if possible.

The energy collected and daily efficiency of the entire preheat field and each of the three collector groups within the preheat field would be measured for a minimum of five 'good' insolation days at each collector outlet temperature which will establish baseline performance data for the preheat only field.

Solar Boiler Field - Preheat Mode

The solar boiler field would be tested in the preheat mode to establish its performance in a manner similar to the testing of the preheat field. Each of the six collector groups in the solar boiler field would be tested individually to determine energy gain and daily efficiency. The test would consist of adjusting flow to achieve an collector outlet temperature of 38°C (100°F) for a single 'good' insolation day. The test will be repeated for an outlet temperature of 121°C (250°F). The test would be conducted on the following individual collector groups: SCB 401 through 460, 461 through 520, 521 thru 580, 581 through 640, 641 through 700 and 701 thru 760 for a total of twelve test days.

Next, the performance of the entire boiler field in the preheat mode would be measured. Field flow rate would be adjusted to yield 38°C (100°F) outlet temperature and energy gain and field array efficiency would be measured for a minimum of five good insolation days to establish a baseline. This test would be repeated for a field outlet temperature of 121°C (250°F) which is the normal outlet temperature for the preheat mode.

Solar Boiler Field - Steam Flash Mode

The previously described preheating tests would result in liquid temperature out of the solar field in the range of 38°C to 149°C (100°F to 300°F). In this temperature range, the water can be effectively utilized by the conventional boiler. Steam requirements at Edison, however call for the solar boiler loop to operative with design inlet temperature of 272°C (521°F) and design outlet temperature of 282°C (540°F) with 5957 kPa (865 psia) steam injected into the steam distribution line. Steam at lower pressures cannot be used in the well; and higher pressures would degrade the collector, therefore the solar boiler subsystems testing in the steam generation mode would be conducted at design operating conditions to establish a performance baseline.

The test would consist of measuring the energy gain and efficiency for three good insolation' days for each of the six solar boiler groups individually at the design flow rates and outlet temperatures. Once this test is completed, the entire solar boiler field could be operated at design conditions for ten good insolation days to establish its performance baseline. At the conclusion of this test, the STEOR field woulf begin the system performance tests.

7.2.2.2 System Performance Testing

System performance testing makes up the bulk of the two year test program of the STEOR field. It is in this portion of the test program that the technical and economic feasibility of operating a large STEOR field would be determined. The system performance test consists of operating the STEOR system according to the operating modes described in Section 5 of the Final Report and recording and processing the performance and operational data described in Section 7.2.1 The SDAS would be programmed to generate daily performance summaries for each of the parameters described in Table 7-1. The daily system performance summaries would be combined with the maintenance log books to form the basis of STEOR monthly test reports. In addition to reporting the parameter values for the current month, the parameters described in Table 7-1 would be plotted on individual graphs to show a performance history for the STEOR field in order to determine any long term changes in STEOR performance. The design of the STEOR sensors and SDAS would result in continuous performance monitoring of the system at three levels: individual collectors, groups of collectors (48 in preheat and 60 in steam flash sections) and collector subsystem level (144 in preheat and 360 in steam flash). In this way, performance changes at the system level could be related to environmental factors (e.g. insolation), system parameters (e.g. flow rate) and also individual collector performance changes.

7.2.2.3 Testing Schedule

The schedule of STEOR subsystem and system performance tests is given in Table 7-3. The testing period is scheduled for 24 months, with the first seven months devoted to subsystem testing and the remaining seventeen months devoted to STEOR system level tests. Monthly progress reports and a final summary reports would be issued according to the schedule of Table 7-3. Details of data reduction and reporting are given in the next section.

7.2.3 DATA ACQUISITION ANALYSIS AND REPORTING

7.2.3.1 Acquisition and Analysis

Automated Data Acquisition

The STEOR performance data would be acquired, stored and processed on site by means of the site data acquisition system (SDAS). The SDAS includes the number and type of sensors listed in table 7-1, computer based data acquisition and processing hardware and the necessary system software which are described in the following paragraphs. The following are key features of the SDAS concept which has been selected for STEOR.

- It is completely separate from the collector and process control system.
- It can acquire, store and process all performance data on site eliminating the need for remote data processing.
- It is more flexible than data logging systems or pure analog systems.

The baseline SDAS consists of an onsite, multitasking language based minicomputer with analog to digital converters and peripherals including dual floppy disc for program and data storage, input keyboard, CRT for data display and a line printer for hard copy of data. The SDAS can perform the following functions:

- Scan all sensors within a two minute time period out of the nominal five minute scan interval.
- Convert the analog signals to digital form and store the data on the data disk.
- Perform all required computations including averaging, and integrating as indicated by Table 6-1 in a batch mode basis.
- Output the performance data to a hard copy printer with data arranged in a report compatible format.

- o Provide alarm display and print capability for all channels.
- o Provide continuous display of selected variables.

The hardware elements of the SDAS are shown schematically in figure 7-3. Up to 100 analog data channels are input to the multiplexer section of the minicomputer which switches each analog signal to the A/D converter section. The digital information from the A/D converter is stored temporarily in the memory portion of the minicomputer. All data from one scan is stored in the memory and after the CPU performs the required computations, the sensor data and subsequent computations are dumped from memory to the disk storage. The data storage disk provides a permanent record of all STEOR performance data. The disk has a storage capacity of 500K Byte which is approximately 2-3 days of data scans at five minute intervals. The disk system contains two disk drives, one for the storage of system data and the second disk for storing the system programs.

The central processing unit is a computer with a 64K word memory. It also includes the following:

- o Real time clock
- o RS232 port compatibility
- o Disk interface controller
- o CRT/keyboard controller
- o Memory backup unit (power supply)
- o Floating point firmware
- o Complete system operation and programming instructions/manual

The other system elements shown in figure 7-3 are the CRT display, a line printer, and a keyboard. System commands or data processing programs are entered through the keyboard in the appropriate software language. The CRT is used to display inputs, and selected output data channels and parameters. The line printer can provide the hard copy of the STEOR performance data in a format compatible with the monthly report requirements. An approximate cost breakdown is shown in table 7-4 for the entire SDAS, including sensors, hardware, software, supplies and maintenance.

<u>Manual Data Acquisition</u>

As outlined in Section 7.2.1 the STEOR operational and maintenance data would be manually entered in a system log book. Daily entries would be made describing all maintenance events, weather conditions, system operating mode and all system malfunctions. The log book would be kept by the STEOR system operator and would remain onsite in the system control room.

7.2.3.2 Data Reporting

Monthly performance reports would be issued for the two year test period as shown in table 7-3. The following information would be contained in the monthly report.

- o System Description

  A paragraph giving a basic description of the system including collector type, area, and orientation; storage capacity; process; and operating modes. This would be the same in each monthly report.

- o Progress During Reporting Period

  This would begin with a description of actions taken to correct problems cited in previous monthly reports. New problems encountered and any significant events in system operation or maintenance would be listed. Any effects on solar system availability or efficiency due to TEOR operation schedules should be discussed.

- o Performance Summary

  The monthly solar system utilization fraction would be reported. This is defined as the ratio of total monthly solar radiation incident on the collector array during periods of collector pump operation to total monthly solar radiation incident on the collector array at all times.

  System performance parameters as listed in paragraph 7.2.1 would be reported for a single clear day when the system was functioning and also for the month. For both the single day and monthly case, a table of results and a performance graph would be included with a description of performance. The tables and graphs would contain the following data:

  Single Day Table:

  The following parameters would be reported as hourly averages from midnight to midnight: direct normal insolation, collected energy (mC_p T across collectors), collector array inlet and outlet temperatures, ambient temperature, wind speed, array efficiency, average storage tank temperature, energy delivered to process (itemized if applicable), temperature and pressure to parasitic energy, fossil fuel saved and total energy to process. In addition, all energy items, insolation, and fossil fuel saved would be summed for the day and a daily solar fraction would be given.

Single Day Graph:

The following parameters would be plotted vs. time on an hourly basis: direct normal insolation, collected energy, average storage tank temperature, energy delivered to process, and parasitic energy.

Monthly Summary Table:

All of the summary items as listed for the single day table (all energy items, daily insolation, solar fraction, and fossil fuel saved) would be listed for each day of the month. In addition, all of these items would be summed for the month.

Monthly Summary Graph:

All items specified for the single day graph would be summed for each day and plotted vs. day of the month.

- Cost Report

  Operating and maintenance costs and fuel costs accrued during the reporting period would be listed in this section.

- Planned Activities

  This section would include any anticipated modifications in system operation or configuration and instrumentation.

Final Report

Twenty four months after the date that the solar system would become operational, a Phase IV Final Report would be written and supplied to DOE within one month. This report would consist largely of a combination of the monthly reports with summaries of all the performance parameters. The report would be organized as follows:

- System Description

  A detailed description of the system including collector type, area and orientation, storage type and capacity, process, and operating modes.

- Significant Events

  A discussion of the problems encountered with the solar system and actions which were taken to solve them. Ths would include not only technical events, but non-technical as well - such as changes in TEOR operations, work shifts, etc. Maintenance and reliability problems related to materials, components and systems would be discussed in detail.

- Performance Analysis

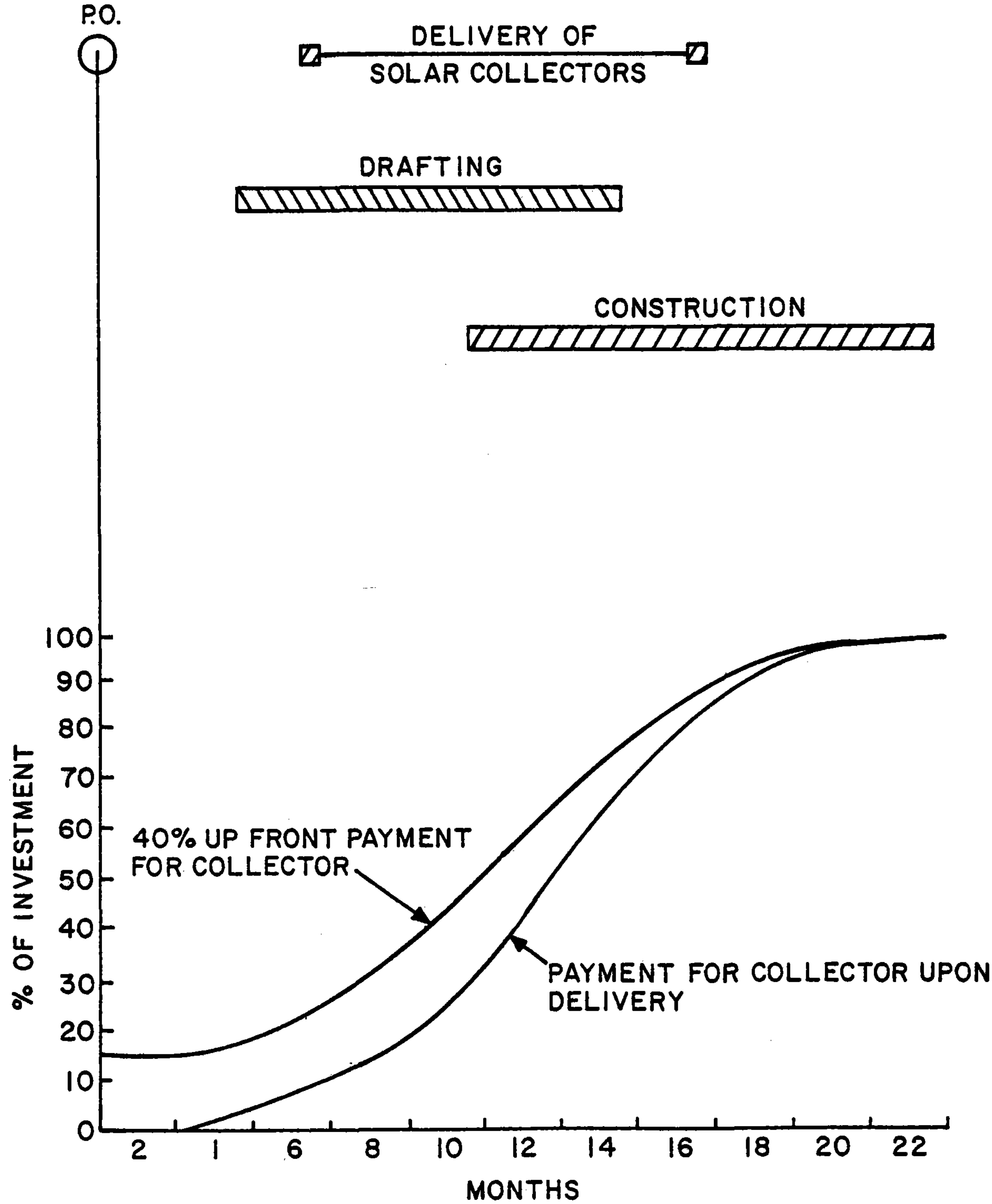
  All of the monthly summary graphs and tables from the monthly reports would be presented. A discussion would be given which compares and explains these results and gives reasons for any anomalies. An annual performance table and annual performance graph would be produced modeled after the monthly tables and graphs but plotting total monthly values vs. month of the year. Major parameters would also be totaled for the year. Where performance appears to have a strong seasonal dependence similar results would be prepared to summarize the performance of each season.

References To Section 7

1. C.F. Kutscher "Data Acquisition and Analysis Guidelines for IPH Demonstration Projects" March 30, 1979 Memo to IPH Steam Contractors

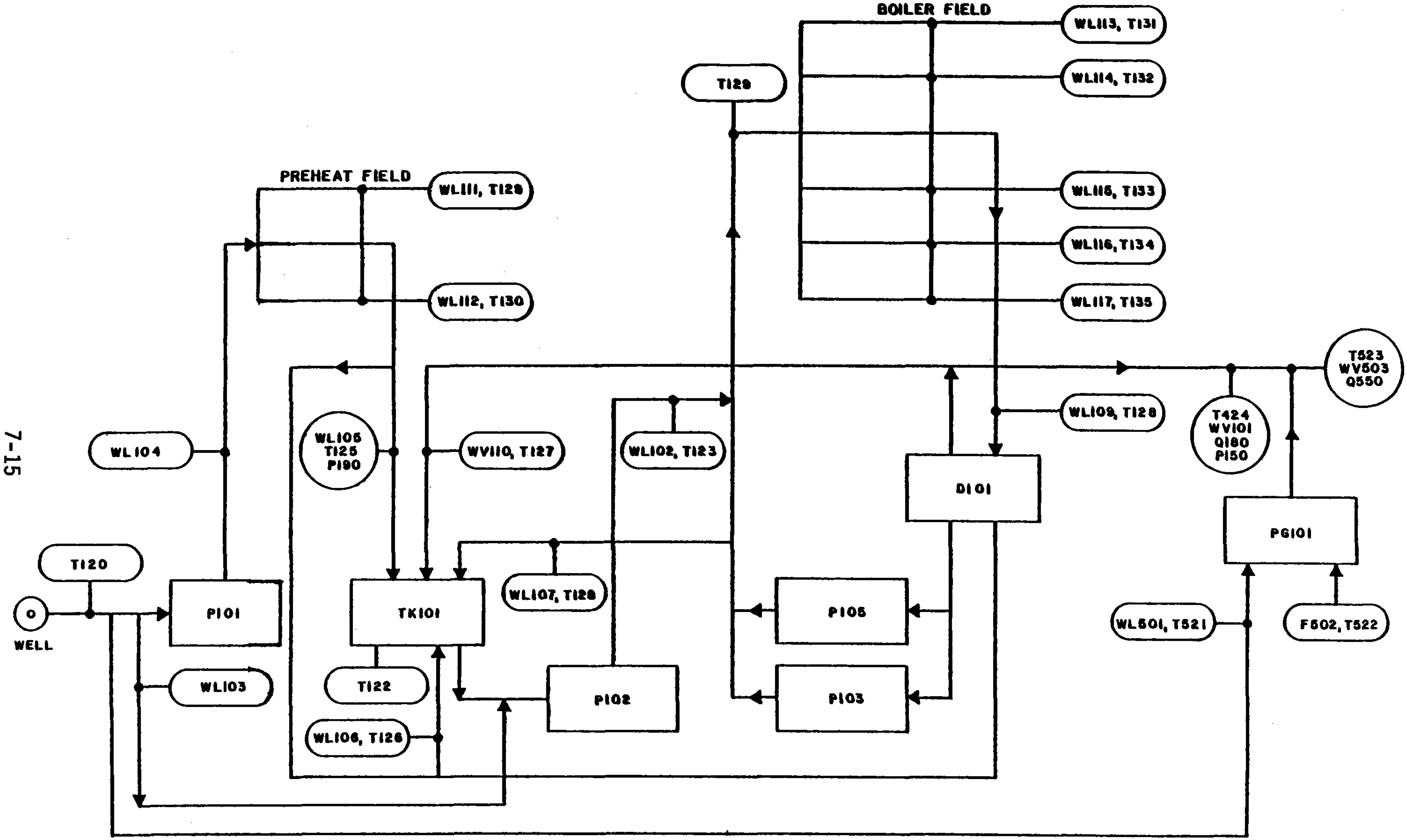
2. E. Streed et al, "Thermal Data Requirements and Performance Evaluation Procedures for the National Solar Heating and Cooling Demonstration Program" NBSIR 76-1137, Aug. 1978

3. IBM Corp. "Instrumentation Installation Guidelines" Solar/0001-77/15, Nov. 1977



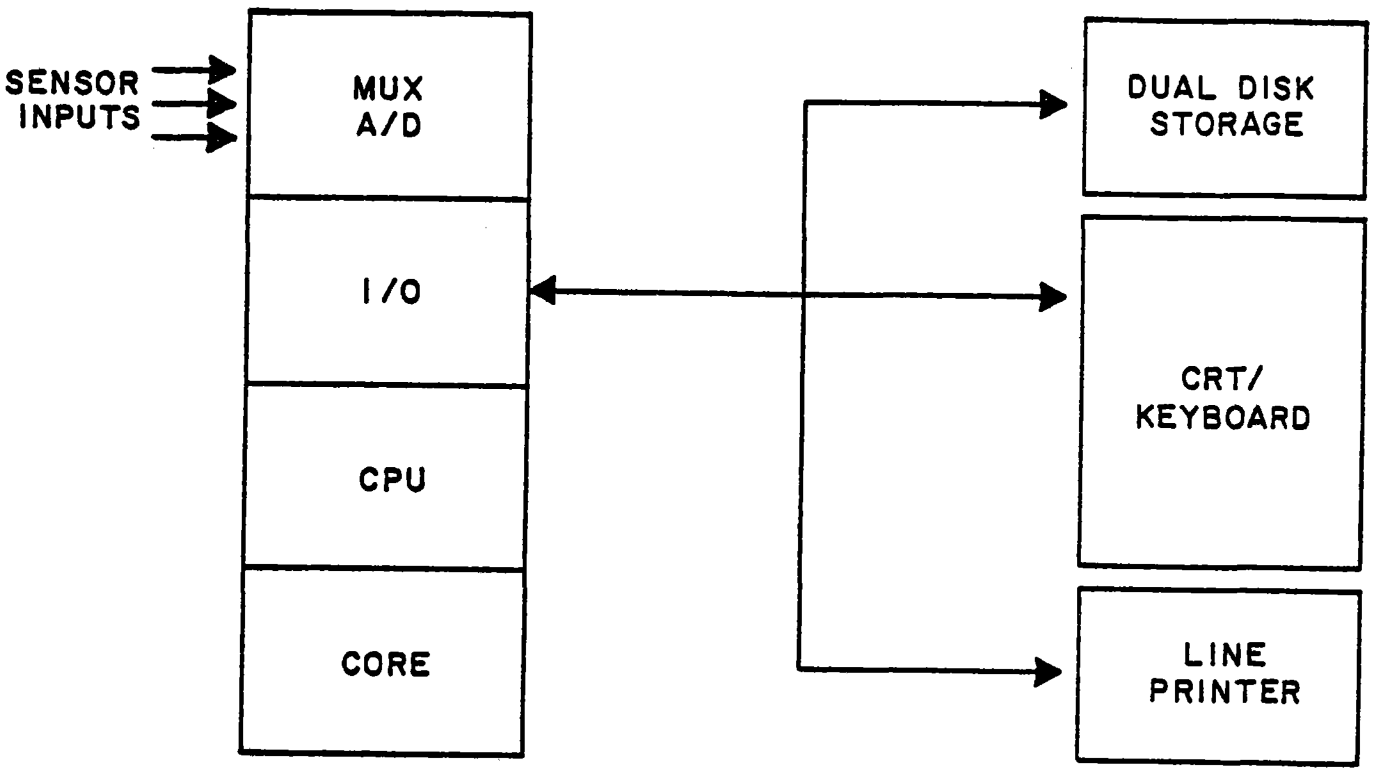
SCHEDULE AND EXPENDITURES FOR SOLAR STEAM PROJECT

FIGURE 7.1



SENSOR LAYOUT DIAGRAM

FIGURE 7.2



SDAS COMPUTER CONFIGURATION

FIGURE 7.3

Table 7.1

STEOR Sensor Details

Parameter (Subsystem)	Properties Measured	Sensor Type	Sensor Designation (See Glossary)	Energy Balance Equation, Comments
A (Total Energy)	-	-	-	Not measured directly A = B+C
B (Preheat Delivered)	Liquid Flow Temperatures	Fluid Meter RTD	WL100 T120 T121,T122	B = WL100*HF(T121) -(WL104+WL103)*HF(T120) +(DM*T122)
C (Steam Delivered)	Steam Flow Steam Pressure Steam Quality Steam Temp. Liquid Temp. (Inlet) Liquid Flow (Inlet)	Flow Meter Pressure Transducers Quality Transducers RTD	WV101 P150 Q180 T124 T123 WL102 WL109	C = WV101*Q180*HV(T124) +(WL102-WV101)*HF(T124) -WL109*HF(T129)
D (TK101 Storage Energy Balance)	Liquid Flow in	Flow Meter	WL105 WL106 WL107	D = (WV110) *+Q180*HV(T127)
	Liquid Temp. in	RTD	T125 T126 T128	+WL107*HF(T128) +WL105*HF(T125)
	Steam Flow in Steam Temp. in	Flow Meter RTD	WV110 T127	+WL106*HF(T126) -[WL102*HF(T123) +WL100*HF(T121)]
	Liquid Flow out	Flow Meter	WL102 WL100	
	Liquid Temp. out	RTD	T123 T121	

Table 7.1 (con't)

Parameter (Subsystem)	Properties Measured	Sensor Type	Sensor Designation	Comments, Energy Balance Equation
E (Preheat Field Output)	Liquid Flow Temp. in Temp. out	Flow Meter RTD RTD	WL104 T120 T125	E = WL104*[HF(T125)-HF(T120)]
F (Boiler Field Output)	Liquid Flow Temp. in Temp. out	Flow Meter RTD RTD	WL109 T129 T128	F = WL109*[HF(T128)-HF(T129)]
G (Preheat Group Output)	Liquid Flow Liquid Flow Temp. out Temp. out	Flow Meter Flowmeter RTD RTD	WL111 WL112 T129 T130	G1 = WL111*[HF(T129)-HF(T120)] G2 = WL112*[HF(T130)-HF(T120)] G3 = F-(G1+G2)
H (Boiler Group Output)	Liquid Flows Temp. out	Flow Meters RTD's	WL113 117 T131 135	H1 = WL113*[HF(T131)-HF(T129)] H2 = WL114*[HF(T132)-HF(T129)] H3 = WL115*[HF(T133)-HF(T129)] H4 = WL116*[HF(T134)-HF(T129)] H5 = WL117*[HF(T135)-HF(T129)] H6 = F-(H1+H2+H3+H4+H5)
I (Individual Collector Outputs)	Liquid Flows Temp. out	Flow Meters RTD's	WL118 126 T136 144	I1 = WL118*[HF(T136)-HF(T104)] I2 = WL119*[HF(T137)-HF(T104)] I3 = WL120*[HF(T138)-HF(T104)] I4 = WL121*[HF(T139)-HF(T104)] I5 = WL122*[HF(T140)-HF(T104)] I6 = WL123*[HF(T141)-HF(T104)] I7 = WL124*[HF(T142)-HF(T104)] I8 = WL125*[HF(T143)-HF(T104)] I9 = WL126*[HF(T134)-HF(T104)]

Table 7.1 (con't)

Parameter (Subsystem)	Properties Measured	Sensor Type	Sensor Designation	Comments, Energy Balance Equation
J (Array Efficiencies)	Direct Normal Insolation	Normal Incidence Pyrheliometer	I001	$JE = 1/AE \frac{T_E}{T_{I001}}$ $JF = 1/AF \frac{T_F}{T_{I001}}$
K (Parasitic Energy)	Pump Electrical Power Collector Drive Power	Watt-Hour Meter	EP600 EP601	K = EP600+EP601
L (Operating Temperatures)	Various Temperatures Pressures	RTD Pressure Transducers	T104, 125, 128, 129 P190, 191	
M (Environmental Parameters)	Direct Normal Insolation Total Horizontal Insolation Ambient Temperature Wind Velocity Relative Humidity	N.I.P. Pyranometer RTD Velocity Transducer Humidity Transducer	I001 I002 T003 V004 RH005	
N (Conventional Boiler Parameters)	Feedwater Flowrates, Temperatures Fuel Inlet Flowrate, Temperatures Outlet Steam Flowrate, Temperatures Steam Quality	Flow Meters RTD RTD RTD RTD RTD Quality Transducer	WL100, T121 WL501, T521 F502 T522 WV503 T523 Q550	N1 = WV503*HV(T523*Q550) +[(WV503-(WL501+WL100)]*HF(T523) N2 = WL100*HF(T121)+WL501*HF(T521) N3 = N1-N2 N4 = F502*FEC $N5 = \frac{N3}{N4}$

Table 7.1 (con't)

Symbol Glossary

WL - Liquid Flow Rate

WV - Vapor Flow Rate

T - Temperature

P - Pressure

Q - Steam Quality

I - Insolation

V - Wind Velocity

RH - Relative Humidity

EP - Electric Power

F - Fuel Flow Rate

HF - Enthalpy Liquid

HV - Enthalpy Vaporization

DM - Change in Storage Mass

FEC - Fuel Energy Content

Table 7.2

STEOR Subsystem Test Schedule

Test No.	Description	Instrumentation Parameter Group	Week 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
7.1	Boiler Sub System Test	N	X	—	X													
7.1.1	Normal Rate																	
7.1.2	- High Rate				X	X												
7.1.3	- Low Rate					X	X											
	Report					X	—X											
7.2	Solar Pre-Heat Testing	G,E																
7.2.1	SCP 101-148	G1					X	X										
7.2.2	149-196	G2						X	X									
7.2.3	197-244	G3							X	X								
7.2.4	101-244	E								X	—	—	—	X				
	Report									X	—	—	—	—X				
7.3	Solar Boiler Pre-Heat Tests	F,H																
7.3.1	SCB 401-460	H1													X—X			
7.3.2	461-520	H2														X—X		
7.3.4	521-580	H3															X—X	
7.3.5	581-640	H4																X—X

Table 7.2 (con't)

Test No.	Description	Instrumentation Parameter Group	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
7.3.6	641-700	H5	X—	—X													
7.3.7	701-760	H6		X—	—X												
7.3.8	SCB 401-760	F,H			X—	—	—X										
	Report				X—	—	—	—X									
7.4	Solar Boiler Steam Flash	F,H															
7.4.1	SCB 401-460	H1						X—	—X								
7.4.2	461-520	H2							X—X								
7.4.3	521-580	H3							X—	—X							
7.4.4	581-640	H4									X—	—X					
7.4.5	641-700	H5										X—X					
7.4.6	701-760	H6										X—	—X				
7.4.7	401-760												X—	—	—X		
	Report												X—	—	—X		

Table 7.3

STEOR Phase IV Test Schedule

Test	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Subsystem																								
o Fossil Boiler	X	X																						
o Solar Pre-Heat	X	—	X																					
o Solar Boiler			X	—	—	—	—	—	X															
System Testing							X	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	X
Monthly Reports			X	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	X
o Final Report																								

Table 7-4

Approximate SDAS System Costs

Computer	
64K Word Minicomputer with A/D converter and multiplexer, CRT/keyboard for 100 channel analog input	$ 13,000
o Interrupt Priority Encoder	900
o Pacer Deck Card	400
o Cable Assemblies (2)	200
Peripherals	
Dual Floppy Disk System	5,000
Line Printer	1,500
Asynchronous Line Controller	700
Signal Conditioning	
o RTD Signal Conditioners (30)	6,300
o Flow Transducer Conditioners (30)	1,600
o Pressure Transducer (3)	700
o Other Voltage Conditioners (16)	800
Subtotal	$ 31,100
Sensors, Wire, Installation (85)	85,000
Total Hardware	$116,100
Software Charges (600 man hours)	$ 24,000
Checkout and Installation	$ 20,000
Total Capital Costs	$160,100
System Maintenance Charges	$ 5,000/yr.
Paper and Supplies	$ 1,000/yr.
Total Annual Charges	$ 6,000/yr.

8. MARKET AND ECONOMIC ANALYSIS

In order to understand the long term feasibility of solar energy in this application, detailed analyses of market and economic characteristics were undertaken. In addition and at the request of D.O.E., an evaluation was made of the feasibility and desirability of financing and incentives options which had been suggested as attractive for enhancing the acceptance of solar technology. For the market analysis, a screening process was performed which considered growth in demand for energy, surface suitability for collectors and energy balance constraints. For the economic analysis, assumptions were developed and projections were assembled to indicate the requirements for solar improvements to reach economic breakeven with fossil energy. Several first-order tests of reasonableness were performed to illustrate the implications for DOE and manufacturers of a significant adoption of solar technology in oil recovery applications.

8.1 Project Future Supply and Demand for Heavy Oil

8.1.1 INTRODUCTION

The principal objective of this section was to identify an upper limit for the STEOR market potential. This limit was assumed to be the capacity set by the technical and economic maximum likely producing rates for steam enhanced oil recovery techniques. A secondary objective was to select a widely known, non-proprietary world oil price forecast which could be used to estimate the cost of enhanced oil recovery boiler fuel.

We proposed to accomplish this effort by reviewing published studies and by summarizing data about existing conditions in the market for heavy crude oil. Three areas of particular interest were: future producing rates for steam enhanced oil recovery processes; potential for downstream limits upon the demand for heavy TEOR-produced crudes; and potential changes in market factors resulting from the removal of price controls and any related taxes.

Our initial literature review indicated that there were a number of studies on enhanced oil recovery, many oil price forecasts and two current studies of refinery capacity. Cursory examination, however, indicated that given our limited objectives of a first order upper limit on TEOR production and a widely known oil price forecast, the following sources would be sufficient:

Subject	Source (8-1, 8-2, 8-3)
1. Enhanced Oil Recovery Production	1. National Petroleum Council Study on EOR (NPC) (1976)
2. World Oil Prices	2. National Energy Plan II (NEP II) (1979)
3. Downstream Impacts of Thermal Enhanced Oil Recovery	3. California Supply Scenario Study (1980)

During the time period of this study, world oil prices climbed significantly faster than our original NEP II baseline. We therefore decided to adopt a more current forecast as noted in section 8.1.4. Also, the focus of our interest shifted from understanding price decontrol effects to examining the impact of the Windfall Profits Tax, (Public Law 96-223,) enacted April 2, 1980. We have carefully reviewed its effect on expected crude oil boiler fuel costs. We have also noted the increased attractiveness it puts on some E.O.R. investments relative to other more heavily taxed oil field applications. (This point has also been noted in published articles) (8-4).

The reader should note that volumetric and price quantities in Section 8 appear in the customary industry units of barrels. The metric equivalent is 0.1590 m^3 per barrel.

8.1.2 PROJECTIONS OF THERMAL ENHANCED OIL RECOVERY PRODUCTION TO 1990

We assumed at the outset that the impact of solar energy in the near term (1981 to 1990) would be as an energy cost reducing investment. Therefore, we needed to first determine those projects which were economic using fossil energy (oil-fired boilers). To a first order, the solar market can be expected to be limited to the total of all new fossil boiler capacity additions (times an appropriate solar fraction). In this initial examination, we elected not to include any retrofit market for fuel saving in existing boiler capacity (i.e. those boilers which might have sufficient life remaining to provide for an economic solar investment). This section and section 8.3 provide estimates of the demand for additional generating capacity.

8.1.2.1 Data Sources

One could use existing historical production trends for thermal EOR projects to project the future. However, given the complexity of decisions involved in production additions and the continuing depletion of current projects, simple historical extrapolations are probably insufficient. More detailed methods must be used to estimate future producing levels.

While there are many sources of data and projections pertaining to the heavy oil--EOR--market, they differ in the methodologies employed to arrive at their estimates, for example:

Study	Date	Methodology
National Petroleum Council (NPC)	1976	Detailed reservoir survey & development model, plus economic analysis
Lewin Associates (8-5)	1976, '78	Detailed reservoir database, but less screening at reservoir level and optimistic field properties
OTA (8-6)	1977	Detailed reservoir data & conservative process assumptions
EIA (8-7)	1979	Econometric model
California Supply Scenario Study	1979-80	Consensus production forecast for major reservoirs

Three of the studies; NPC, OTA, and Lewin; worked from a single database of reservoirs. The other two studies did not and therefore are probably less accurate. The California Supply Scenario represents a consensus forecast, the producing rate to 1985 being an assumption. Of the three reservoir based scenarios, Lewin is the most optimistic. The authors of the NPC report faulted the Lewin study in three areas:

+ Reservoir screening (insufficient)
+ Process modeling - thickness, sweep, efficiency (too ideal)
+ Cost estimates (low)

The OTA report criticized both Lewin and NPC for the assumptions used to extrapolate from data based on the best reservoir areas (which, logically, have been developed first) to the reservoir as a whole (where conditions will be less optimal). On a quantitative basis, the ultimate recovery due to steam EOR is approximately projected as follows: (rough comparison)

	Billion BBLs	Oil Price
Lewin	13-14	\$17/BBL (Highest Price)
NPC	4-5	\$25/BBL
OTA	3-6	\$22/BBL

NOTE: Many differing economic assumptions were used in these studies which make direct comparisons among them difficult. These figures are, however, representative of their positions.

We selected NPC as the best study for our purposes. One reason was that as participants in its development we had access to some of the original data base materials (8-8). A second reason was that since NPC was an industry document, it was likely to be more widely accepted within the producer community.

8.1.2.2 Projected Thermally Enhanced Oil Production and Steaming Capacity

The geographical distribution of reservoirs in which conventional steam recovery projects are likely to be feasible is heavily concentrated in California. Published data indicates: (8-9, 8-10)

State	Potential Reserves (Billion BBL)	Reserves In Most Favorable Reservoirs (Billion BBL)	1979 Steam Production BBL/Day
California	53.6	33.4	291,000
Texas	30.6	3.4	1,900
Arkansas	5.0	4.1	800
Louisiana	6.4	0.8	700
Wyoming	5.3	2.7	800
Other States	5.7	1.5	700
US Total	106.8	45.9	295,900

The NPC study presumed that 80% of all steam EOR would be from California (98% today). In Texas, NPC assumed virtually all thermal EOR would be wet-combustion due to geologic conditions in the favorable reservoirs. NPC allocated 17% of U.S. future steam EOR to Arkansas and Louisiana, and 3% to the remaining states (8-11). These NPC figures strongly suggest that California is the territory with the major potential for STEOR, especially given the greater annual direct normal insolation values for California oil fields versus values for oil fields located in the gulf coast region.

Within California, the distribution of heavy oil suitable for STEOR is concentrated in the Kern County/San Joaquin Valley area. Other California heavy oil fields, while sizeable, are located in unfavorable terrain areas, e.g. in urban areas (see Task 8.3). To project our first estimate of maximum heavy oil producing rates, we have used the backup data to the NPC study to approximate the percentage of Kern County reservoirs included in the NPC database. Using the $15/BBL scenario of the NPC study, we obtained the following estimates, assuming Kern County production is 63% of the California total (for 1980-2000 NPC study based estimates): (8-12)

Producing Rate in 1000 BBL/DAY
(1979 Actuals and 1980-2000 Projections)

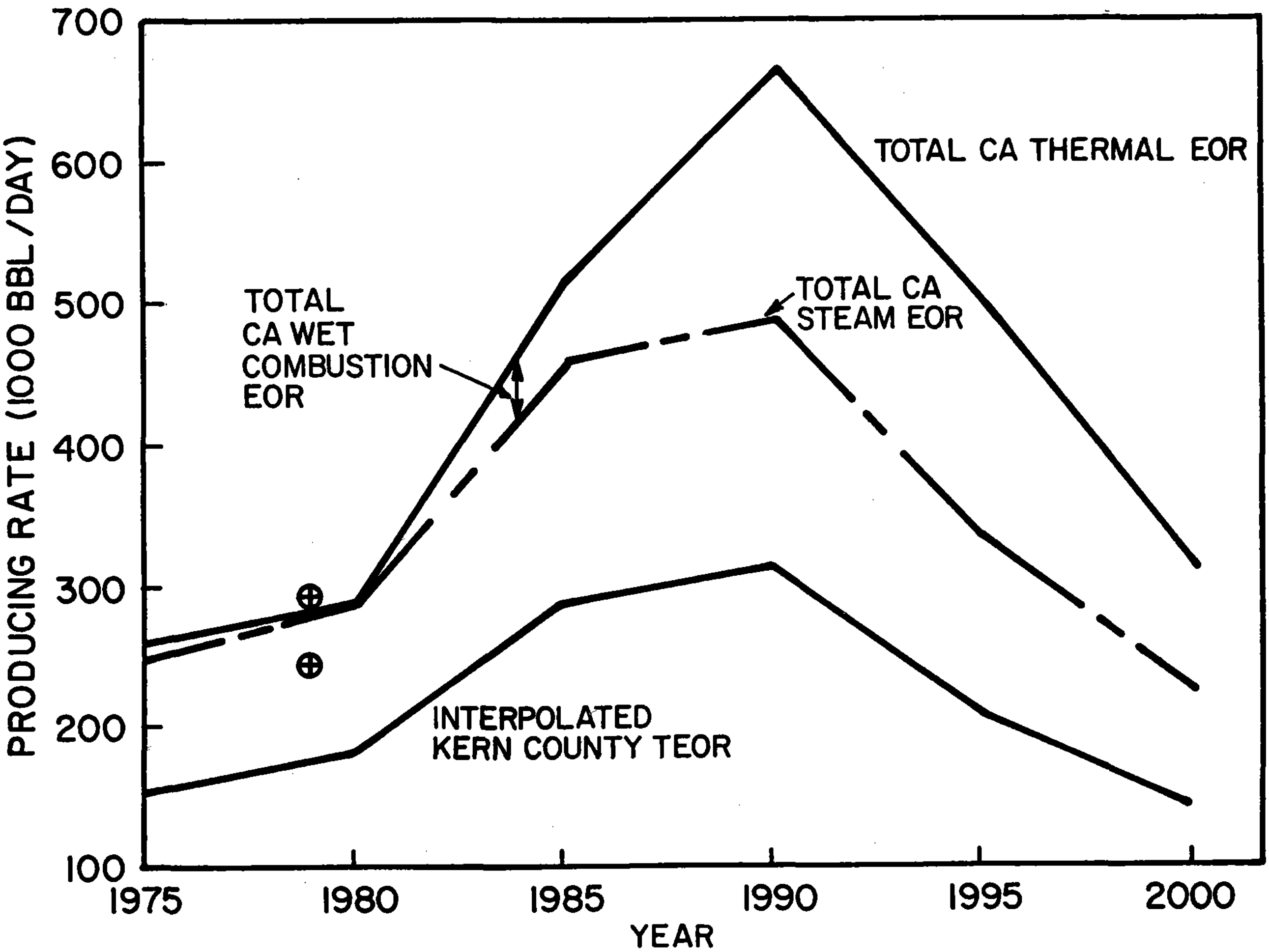
Year	Total US Thermal EOR	Total CA Steam EOR	Assumed Kern County Steam EOR
1979	296	291	246
1980	300	285	180
1985	600	460	290
1990	800	490	310
1995	600	330	210
2000	300	220	140

NOTE: The Kern County Fields represented 63% of the NPC data base estimated TEOR incremental recovery.

Figure 8.1 shows the producing rate projections we interpolated from NPC. If one assumes an oil-to-steam ratio of 0.2 and a conversion of 1BBL of steam per 0.103 MWh (2.85 BBL of steam per Million BTUs), then the implied change in steaming capacity resulting from the NPC production projections is:

Steaming Capacity in 10^3MW (10^9 BTU/HR)

Year	California	Kern County	Change In Capacity For Kern County
1980	6.2 (21)	8.8 (13)	0.3 (1)
1985	10.0 (34)	6.2 (21)	2.3 (8)
1990	10.6 (36)	6.7 (23)	0.6 (2)
1995	7.0 (24)	4.4 (15)	-2.3 (-8)
2000	4.7 (16)	2.9 (10)	-1.5 (-5)



⊕ OIL & GAS JOURNAL SURVEY POINTS FOR CA & KERN COUNTY

INTERPOLATED ESTIMATE FOR KERN COUNTY, CA
TEOR PRODUCTION

FIGURE 8.1

If this scenario were true, a 3.8 x 10^3MW (13 x 10^9 BTU/hr) capacity reduction would occur after 1990. A plausible explanation would be that the change would result as operators scrapped the older 3.8 x 10^3MW (13 x 10^9 BTU/hr) existing capacity which our conversion factors inferred for 1980.

Since the NPC study was written in 1975, the rapid increase in world oil prices, domestic price decontrol, new environmental rules and the Windfall Tax, etc. have changed the economic parameters assumed by the NPC study. One should, therefore, exercise extreme caution in the use of its projections. In Section 8.3, we have reported future steaming capacity based on data obtained directly from the major California operators. The Section 8.3 data and not this section's simple extrapolation formed the basis for our Section 8.6 market discussions.

8.1.3 DEMAND LIMITATION FOR HEAVY (TEOR) OIL

In the proceeding section, we reviewed the type of published data and analysis which were available to project heavy oil-TEOR production given assumptions of oil price, reservoir and economic data.

An implicit assumption in those analyses was that the future oil prices would be low enough for market clearing demands to exist. In this section, we briefly examine the problem of downstream processing limitations or transport bottlenecks which might impact heavy oil demand.

As part of a cooperative effort, a group of California refiners and state officials have developed an analysis called the California Supply Scenario Study. This effort, published in March, 1980, was conducted to evaluate the impact upon refinery investments and air quality for a number of supply scenarios for the period 1978-1985. The study looked at several output factors including:

1. Refinery equipment needs
2. Refinery investment levels
3. Emissions impacts

The key sensitive input parameters in the model included:

1. Availability of natural gas
2. Availability of imported (low sulfur) crude oil
3. Expanded production of California crude (primarily heavy crude oil from TEOR)
4. Demand for refined products
5. More stringent air quality rules on combustion byproducts

The exact quantititative results were directed principally at refining capacity and processing mix decisions. The sensitivity measures produced by the study's linear programming model show that the concensus-assumed 1978-1985 expansion of California oil production (400,000 BBL/DAY) input variable is one of the least sensitive factors (8-13). This implies that there probably would not be a refinery capacity constraint on TEOR expansion, as a result of increased TEOR production alone.

8.1.4 PROJECTING THE PRICE OF TEOR CRUDE OIL

The discussion which follows is not and should not be interpreted as representing either an Exxon forecast or an Exxon endorsed forecast. The data presented were taken from U.S. Government sources and are assumed to be representative of the data available to private decision makers evaluating investment projects.

In order to estimate the cost of a fossil steam operation for comparison with a solar alternative, a fuel cost forecast is required. On the assumption that the current lease crude oil-fired package boiler will be the standard for comparison, the fuel cost can be estimated as an adjusted cost based upon the average world oil market clearing price. The adjustments required include:

1. A market price penalty (quality debit) of \$3 to \$10 per barrel at any point in time to reflect the undesirable nature of hard-to-process heavy crude. Given a finished product price, which is based on costs of refining light, low sulfur crude oils (purchased at "world prices"),a heavy crude which will cost more to refine will command a lower price from the refiner. Historical data indicates a smoothed difference on the order of \$3/BBL, but with short term gaps as large as \$10/BBL during periods of rapid price increase (e.g. in 1979) (8-14).

2. A royalty fraction deduction (7% at Edison to 12.5% in typical lease arrangements) to account for the fact that a "working interest" need not pay a royalty on produced crude which is consumed on lease.

3. The payment of the Windfall Profits Tax (WPT) which is a tax levied on the producer. The economic cost of a good which can be either sold in the market or consumed in the business is its opportunity cost, i.e., the revenue foregone from its sale. Here, the revenue foregone with the Windfall Tax imposed is the market price minus the tax. Thus, if the boiler fuel is crude oil from the lease, its fuel cost (market price less WPT) will be lower than the cost of crude oil for fuel purchased at market prices. Lower fossil fuel costs reduce STEOR's attractiveness.

4. The payment of an Ad Valorem Tax (a property tax on reserve net present value) to the local government. We assumed a 6% rate (8-15). Such a tax lowers the opportunity cost as does W.P.T.

Stated in a mathematical formula, we should assume a fuel cost of:

$$C_{fuel} = (1\text{-Royalty})*(P_{world} - \frac{\$3}{BBL} - \text{W.P.T.} - \text{Ad Valorem Tax})$$

where the WPT is:

$$\text{W.P. Tax} = (P_{world} - \$3/BBL - \text{Base} - \text{Severance})* \text{ Tax Fraction}$$

Note: The base and tax fraction are determined from the WPT law according to the tier of oil involved. Our analysis treated the California Ad Valorem Tax as though it were a local production or severance tax. This resulted in an error in calculating the Windfall Tax, because only severance taxes (not Ad Valorem taxes) are deductible from the WPT. The effect of the error was marginal in subsequent calculations.

8.1.4.1 World Price Forecast

Our review of world oil price studies available to the public in October, 1979, suggested that the National Energy Plan II (NEP II) study published in April, 1979, represented a reasonable choice for future oil prices. It was based on an overall consideration of factors affecting world economic growth, and petroleum supply and demand. Three "future" cases were postulated: low demand/high supply, mid-demand/mid-supply and high demand/low supply. Three oil price forecasts were then calculated: high, medium, and low. For our calculations, we employed a method which interpolated between the "high price" and "medium price" curves. To simplify our calculations the method used a single point estimate, $18/BBL, (1979 oil price) and a 3% real price growth rate. We assumed a slightly higher underlying inflation rate (7%) than NEP II. A comparison of our interpolated version with NEP II shows the following correspondence: (8-16)

Constant 1979 Dollars Per Barrel Basis

YEAR	NEP II MEDIUM	NEP II HIGH	INTERPOLATION
1979	$16	$16	$18
1985	$20	$25	$21.5
1990	$23	$30	$25
2000	$32	$32	$33.5

Current Year Dollars Per Barrel Basis

YEAR	NEP II MEDIUM	NEP II HIGH	INTERPOLATION
1979	$16	$16	$18
1985	$28	$35	$32
1990	$42	$55	$51
2000	$100	$120	$133

NOTE: NEP II assumed a 5.5% GNP Deflator, our interpolation assumed a 7% GNP Deflator based on 1979 Presidential Guidelines (8-17).

Since the beginning of our study contract, world oil prices have again undergone a rapid increase similar to the 1973-1974 period. The current price for imported oil averages around $30/BBL (1980), which allowing for a 9% GNP deflator in 1979 would adjust to about $28/BBL in mid-1979 dollars (8-18). This nearly equals the NEP II high price case's 1990 projection. As a result, it was necessary to reconsider the choice of NEP II.

An alternative forecast was found in the projections from DOE's Mid-Term Energy Forecast System which form the basis of recently published rules for life-cycle cost evaluations of Federal Energy Management Programs (10 CFR Part 436, Federal Register January 23, 1980). That rule and other DOE sources provided the following constant 1980 dollar price estimates:

			INTERNAL DOE	
YEAR	MEFS	NEP II HIGH	EARLY GROWTH	BEST GUESS
1980	$30	-	$30	$30
1985	$34.15	$27.25	$45	$35
1990	$40.78	$32.70	$50	$40
1995	$46.22	-	$52.5	$42.5
2000	$52.39	$34.88	$55.0	$45.0

NOTES: 1980 value per DOE sources. Price for 2000 continues 1995 trend in MEFS. 1979-1980 GNP Deflator at 9% used to restate NEP II from 1979 to 1980 dollars.

Since expectations of long term inflation rates are on the order of 8%+ through 1985 and then decline from 6.5% to 6% out to the year 2000, it appears reasonable to continue to use a 7% price deflator baseline (8-19). Our new approximate oil price interpolation would be:

Factor		New	Old
Annual Real Growth Factor	$= \sqrt[20]{\frac{\$52.39}{\$30.00}} =$	2.8%	3%
Annual GNP Deflator	$= \sqrt[20]{\frac{4.00}{1.00}} =$	7.2%	7%
Base Price (1980)	=	\$30/BBL	\$19.80/BBL
Total Annual Price Change Ratio	=	1.10%	1.10%

The resulting current dollar forecasts (old & new) for comparison are:

World Price In Current Year Dollars Per Barrel Basis

Year	Old	New
1980	\$ 19.80	\$ 30.00
1985	\$ 31.89	\$ 48.32
1990	\$ 51.36	\$ 77.81
1995	\$ 82.71	\$125.32
2000	\$133.20	\$201.82

This new world price forecast, when adjusted for the royalty, quality debit, Ad Valorem and WPT effects is the boiler fuel cost expectation which operators of enhanced oil recovery projects could be assumed to use in their investment analysis. It is not an Exxon forecast or an Exxon endorsed forecast.

8.1.5 ESTIMATE THE FUTURE COST OF BOILER FUEL

As was stated in 8.1.4, the cost of lease crude oil fired in the boiler is the resultant of the world oil price less debits for royalty interest, quality, Ad Valorem and Windfall Profits Tax. World oil prices are assumed to follow the scenario outlined in the previous section. The working interest fraction (i.e., 1 minus royalty interest) is customarily 87.5% on royalty properties and 100% on company fee properties. For an actual TEOR project, the actual fraction varies in proportion to the royalty interest on a field wide basis. At the Edison Field, Exxon's working interest is about 93% (8-20). The quality debit has historically been about $3/BBL on a rolling average basis. We have elected to inflate this quality debit at the full 10% oil price inflator. This should be conservative, (i.e., overpredicting the effect). The Windfall Profits Tax treatment is discussed next.

Based upon published information, the Windfall Profits Tax can be expected to modify producer revenues according to three pricing tiers (8-21). The basic formulas which will apply to TEOR projects at fields already in production in 1979 were reported as follows:

Simplified Tax Rate Schedule

Pricing Tier	Eligibility	Tax Rate	Approximate Base Price	Base Price Inflator
One	Production begun before mid-1979	70%	$12.81 (5/79)	GNP Deflator
Two	Stripper (less than 10BBL day) & National Petroleum Reserve leases.	60%	$15.20 (1980)	GNP Deflator
Three	Heavy Oil (API Gravity< 16°), Incremental Tertiary, Newly Discovered	30%	$16.55 (1980)	GNP Deflator plus 2%
Exempt	Tertiary Incentive Revenue Oil	"Independents" are exempt by law or net of WPT if a "major producer" (8-22).		

NOTES: Approximate base prices are indicated. Incremental Tertiary Production includes projects beginning (under special WPT definitions) after May 1979 and is counted against a base control production level of 9/78 to 3/79, adjusted downward month-by-month. The tax will phase out starting no later than 1991, but no earlier than 12/1987. Phase out will occur over 33 months. Base prices will be adjusted for location and quality, however, we have ignored this effect to a first order.

To illustrate the impact of the tax upon effective boiler fuel costs, we will assume that the lease crude is heavy (20° API or less), that the quality debit applies and that (for Edison) the actual price will be bounded by stripper (Tier Two) at present and Incremental Tertiary (Tier Three) in the future. A Tier One calculation will also be provided for completeness. We assume the tax has phased out by 1995.

TEOR OIL Price In Current Year Dollars Per Barrel

			(Less 7% Royalty, 6% Ad Valorem, Tax)			
				Less W.P.T. Debits		
Year	World Price	Less Quality Debit	No W.P. Tax	Tier 1	Tier 2	Tier 3
1980	\$ 30.00	\$ 27.00	\$ 23.60	\$ 15.85	\$ 17.92	\$ 21.14
1985	\$ 48.32	\$ 43.48	\$ 38.02	\$ 23.70	\$ 27.10	\$ 33.44
1990	\$ 77.81	\$ 70.03	\$ 61.22	\$ 35.62	\$ 41.17	\$ 53.79
1995	\$125.32	\$112.79	\$ 98.60	\$ 98.60	\$ 98.60	\$ 98.60
2000	\$201.82	\$181.64	\$158.79	\$158.79	\$158.79	\$158.79

Note: As stated previously, the Ad Valorem Tax is not actually deductible from the W.P.T. and hence the costs here are marginally higher than they should be, since Ad Valorem Tax was deducted in error.

The combined royalty and tax effects tend to significantly reduce the opportunity cost of heavy crude oil used by a producer to fuel his steam generators. If he has a Tier One property, the fuel cost is only one half of the market oil price. On the other hand, the Tier Three fuel cost is two thirds of the world price during the W.P.T.

Comparison Of Fuel Costs

Year	NEP II	No WPT	Tier One	Tier Two	Tier Three
1980	100%	151%	102%	115%	136%
1985	100%	151%	94%	108%	133%
1990	100%	151%	88%	102%	133%
1995	100%	151%	151%	151%	151%

Most California EOR fields produce crudes whose API gravity is less than 16° (i.e. they are Tier Three) (8-23). By comparison, many other existing non-EOR properties will be Tier One which yields lower net of tax revenues than Tier Three. Thus, if equal investments were required, the tax structure will return more dollars per barrel for (Tier Three) EOR versus (Tier One) non-EOR (light) oil projects. This incentive for EOR might help STEOR. Also, since the revenues are higher in Tier Three, so are the fuel prices (opportunity costs). While not as costly as world oil purchased on the market, Tier Three fuel costs are now projected to be 33% greater than they were assuming a NEP II basis.

8.2 Product Improvement

8.2.0 INTRODUCTION

In this section, the cost and performance of currently available STEOR-systems using line focus collectors and oil fired steam generators is reviewed in detail and projections are made concerning the nature, timing and impact on cost and performance of a number of collector and non-collector subsystem improvements.

Section 8.2.1 addresses the collector subsystem and Sections 8.2.2 through 8.2.6 address the non-collector subsystems including the steam generator. Overall STEOR system performance and cost projections are developed in Section 8.2.7 and Section 8.2.8 provides a summary including a discussion of potential incentives and capital investment requirements for IPH system manufacturers.

Inputs to Section 8.2 include the STEOR baseline system cost and performance data from Task 2, a survey of DOE sponsored research and development activities and discussions with line focus collector vendors and fossil boiler vendors. The production volume projections developed in Section 8.2.8 serve as an input to the discussions of STEOR market potential which are made in Section 8.6.

8.2.1 COLLECTOR SUBSYSTEM IMPROVEMENTS

8.2.1.1 Introduction and Background

Line focus concentrating collectors which are compatible with enhanced oil recovery requirements (efficient operation up to 300°C (572°F)) must have as a minimum, the following design characteristics.

- o Concentration Ratio greater than 10
- o Continuous tracking about one axis
- o Selective coating on receiver tube

In the past, a number of line focus collector designs have been constructed and tested which have the above characteristics. These designs have varied considerably in their approach to achieving linear concentration of solar energy. Two general design classifications are by the type of imaging system and by the motion of the concentrating element and the receiving element. There are two primary types of imaging systems: refractive and reflective. Some refractive type concentrators employ secondary reflectors in close proximity to the receiver and thus are hybrid imaging systems. The majority of high temperature line focus collectors constructed to date have been of the reflective optics type.

The next general classification of concentrator is by the motion of the concentrator and/or receiver, i.e.

Type 1: Tracking reflector and receiver
Type 2: Tracking reflector, fixed receiver
Type 3: Fixed reflector, tracking receiver

In type 1, both reflector and receiver are structurally joined and both track the apparent motion of the sun. In type 2, either the entire reflector rotates about a fixed receiver or segments of the reflector track the sun to maintain focus on a fixed receiver. In type 3, the reflector element is fixed and usually segmented and the receiver tracks the sun.

Some hardware examples of the above design types include the following:

REFRACTIVE CONCENTRATORS:

- o McDonnell Douglas fully tracking Fresnel Lens Concentrator
- o E-Systems 1-1/2 axis tracking Fresnel Lens Concentrator

REFLECTIVE CONCENTRATORS

Type 1: Suntec, Acurex, Solar Kinetics
Type 2: Del Jacobs, Suntec-Slats
Type 3: General Atomic, Scientific Atlanta

All of these collector designs have particular strengths and weaknesses regarding performance, cost, maintenance, durability and manufacturability. The fresnel lens refractive collectors, for example, have the advantages of using the lens as a cover plate and a structural member and of reduced sensitivity to slope errors. Shortcomings of this approach include the requirement for more than one axis tracking to minimize off normal incident angle effects, and the cost and available sizes of fresnel lenses.

Of the reflective type concentrators, type 1 has the advantage of smaller incident angle-related losses than type 3, but type 1 has the drawbacks of a flexible hose connection to a moving receiver and a drive and support system which must accommodate both reflector and receiver as a single unit. The type 2 reflectors have the advantage of a fixed receiver requiring no flexible hose, but the Del Jacobs approach has a limited aperture (.6M) (2 ft.) and the Suntec-Slats is a fixed aperture, large focal length approach which is more sensitive to incident angle losses than type 1.

An advantage of the type 3 approach is in the simpler receiver drive mechanism, but the longer focal length and fixed aperture makes this approach more sensitive to incident angle effects than type 1.

Given the short history (about four years) of the line focus collector industry, it is difficult to assess the durability and maintenance requirements of the various collector types described above. It is likewise difficult to discriminate based on manufacturing costs because of the limited quantities of each type of collector produced and the prototype nature of the existing line focus designs.

A considerable amount of collector performance data has been generated by the Sandia Labs Collector Module Test Facility (CMTF) in Albuquerque, N.M. The facility is designed to generate peak noon and all day performance data for concentrating collectors operating up to 300°C (572°F). The test collectors are oriented E-W to enable instantaneous efficiency testing at normal incidence on any day of the year. The consistently high insolation in Albuquerque, the use of the same instrumentation, data acquisition equipment, test personnel and test procedures all combine to minimize the environmental and facility related errors in test data.

The results of CMTF performance testing (8-24) of a number of line focus collectors are shown in Figure 8.2 which is a plot of instantaneous collector efficiency based on direct normal insolation and normal solar incidence angle vs. collector outlet temperature. The collectors noted on the graph cover the range of design types discussed previously and also cover a range of optical materials, concentration ratios and receiver thermal design, all of which impact the collector efficiency. For the collector test results shown in Figure 8.2, the following observations can be made:

- The type 1 reflective concentrators (moving reflector and receiver) showed the highest efficiencies.
- The type 3 concentrators (fixed reflector, moving receiver) showed the lowest efficiencies.
- The type 2 reflectors and the fresnel lens refractor showed intermediate efficiencies.

These observations also hold when collector performance is considered on an annual basis. Figure 8.3 shows annual collector efficiency plots vs. temperature from a recent Sandia prediction (8-25). The top two curves are for a type 1 reflector and the lower three are for type 2 and 3 reflective concentrators, respectively.

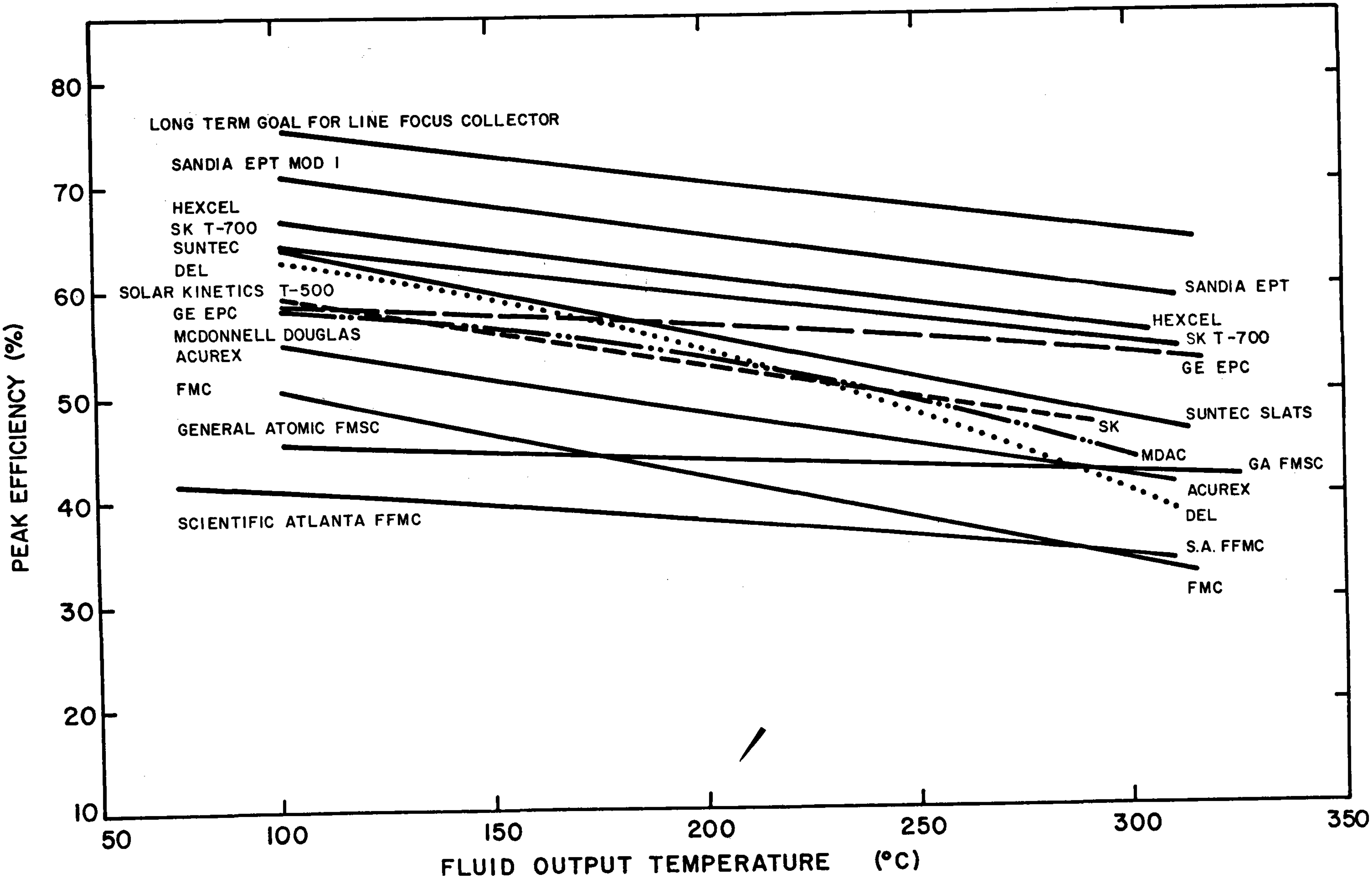
Based on these instantaneous results and annual predictions, the type 1 moving reflector and moving receiver has received the bulk of DOE development and demonstration funding and for this STEOR program, is the only type of collector which meets the program requirements of 300°C (572°F) capability plus installed systems experience.

The following discussions on collector improvements will pertain primarily to improvements in the various design aspects of the moving reflector/receiver type line focus collectors which operate up to 300°C (572°F).

8.2.1.2 SUMMARY OF CURRENT COLLECTOR DESIGNS AND CAPABILITIES

8.2.1.2.1 Physical Characteristics

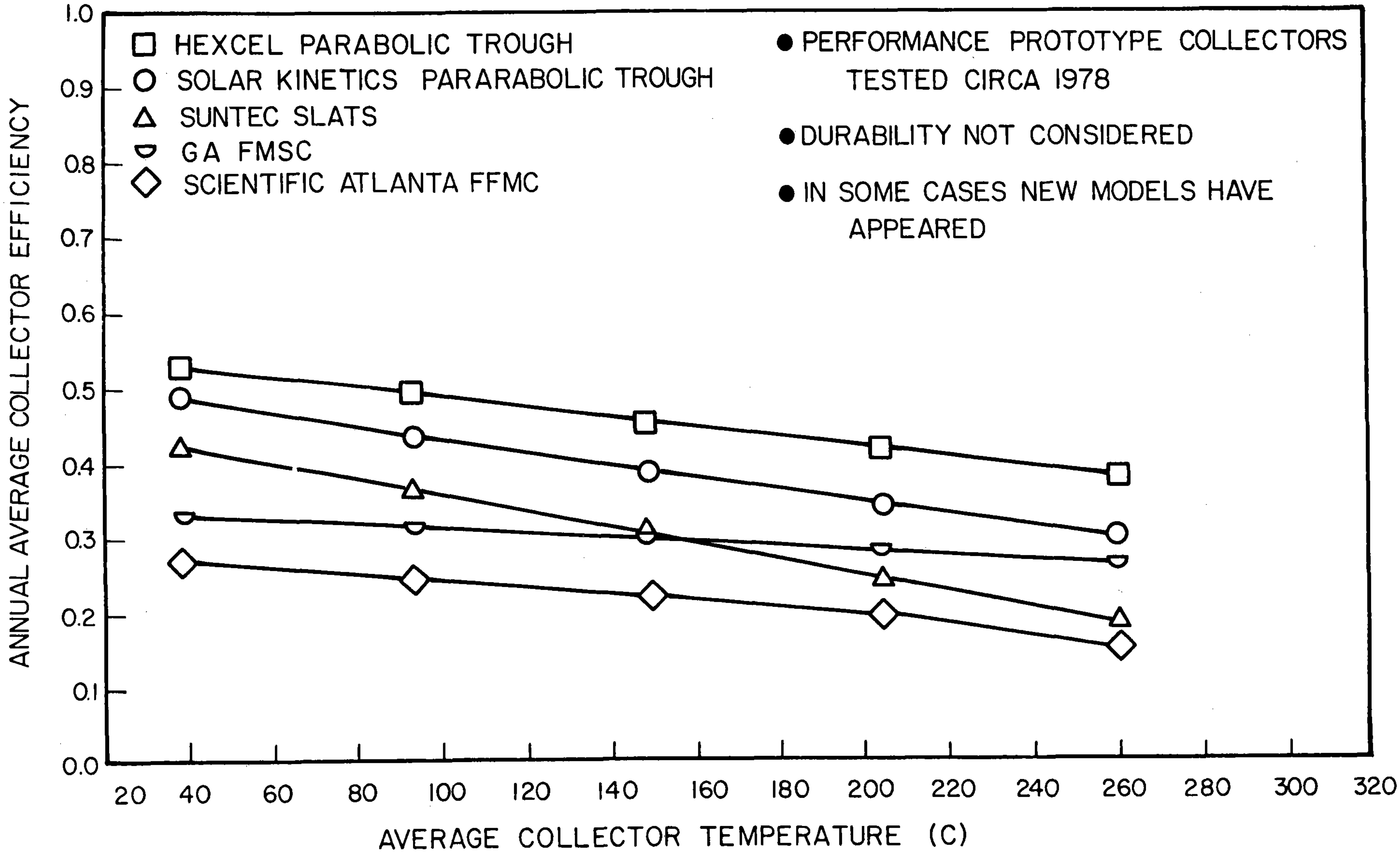
There are currently three U.S. manufacturers of type 1, high temperature line focus collectors whose products have been independently tested at Sandia Labs and installed on several Industrial Process Heat or Heating and Cooling Demonstrations. These are Solar Kinetics, Acurex and Suntec. Physical and material characteristics of these collectors are shown in Table 8.1 along with the Sandia Engineering Prototype Trough (EPT) which has served as the baseline collector design for this study. It is interesting to note the



NOTE: $^oF = (9/5\ ^oC) + 32$

LINE FOCUS COLLECTOR TEST RESULTS

FIGURE 8.2



NOTE: $^{o}F = (9/5\ ^{o}C) + 32$

ANNUAL COLLECTOR EFFICIENCY VS. TEMPERATURE

FIGURE 8.3

TABLE 8-1

LINE FOCUS COLLECTOR CHARACTERISTICS

CHARACTERISTICS	ACUREX	SOLAR KINETICS	SUNTEC	SANDIA EPT
MODEL NUMBER	3001	T-700	SH-1655	
DESCRIPTION	PARABOLIC TROUGH	PARABOLIC TROUGH	PARABOLIC TROUGH	PARABOLIC TROUGH
APERTURE SIZE	1.8m (6.0 FT)	2.1m (7.0 FT)	2.7m (9.0 FT)	2.0m (6.6 FT)
RIM ANGLE	90^{o}	80^{o}	72^{o}	92^{o}
FOCAL LENGTH	.45m (18 IN)	.56m (22 IN)	.91m (36 IN)	.48m (19 IN)
MIRROR SUPPORT STRUCTURE	STEEL RIBS	ALUMINUM SHEET MONOCOQUE ON ALUMINUM BULK-HEADS	ALUMINUM HONEYCOMB	ALUMINUM HONEYCOMB
MIRROR MATERIAL	ALUMINUM SHEET	ALUMINUM ACRYLIC (FEK-244)	ALUMINUM ACRYLIC (FEK-244) OR GLASS	GLASS BACK SILVERED
DRIVE MECHANISM	115VAC GEAR MOTOR WITH SPEED REDUCER AND PROTECTION CLUTCH	HYDRAULIC	24VDC DRIVE OF GEARBOX AND CHAIN	MOTOR/GEARBOX
TRACKER TYPE	SHADOW BAND	SHADOW BAR OR OTHER	SHADOW BAR OR FLUX LINE TRACKER	FLUX LINE
ABSORBER SIZE (O.D.)	3.2cm (1.25 IN)	4.1cm (1.62 IN)	4.1cm (1.62 IN)	3.2cm (1.25 IN)
ABSORBER MATERIAL	STEEL	STEEL	STEEL	STEEL
ABSORBER COATING	BLACK CHROME OVER NICKEL	BLACK CHROME OVER NICKEL	BLACK CHROME OVER NICKEL	BLACK CHROME OVER NICKEL
ABSROBER ENVELOPE	PYREX GLASS TUBE	PYREX GLASS TUBE	GLASS WINDOW, INSULATED BACK	GLASS TUBE
FLUID	WATER OR ORGANIC FLUID	HEAT TRANSFER OIL OR WATER	WATER OR OILS	ORGANIC FLUID
TEMPERATURE LIMIT	$315^{o}C$ ($600^{o}F$)	$315^{o}C$ ($600^{o}F$)	$315^{o}C$ ($600^{o}F$)	$315^{o}C$ ($600^{o}F$)
MIRROR REFLECTANCE	.75-.80	.82-.86	.82-.86	.92-.95
COATING PROPERTIES				
ABSORPTIVITY	.93	.93	.93	.93
EMISSIVITY ($300^{o}C$)($572^{o}F$)	.25	.25	.25	.25
ENVELOPE TRANSMISSION	.90	.90	.90	.90
GEOMETRIC CONCENTRATION RATIO	18	16.5	21.2	20
COLLECTOR MODULE WEIGHT Kg/m^2 (LBS/FT^2)	22.5 (4.6)	19.6 (4.0)	20.0 (4.1)	-
TOTAL COLLECTOR WEIGHT (80' ROW) Kg/m^2 (LBS/FT^2)	27.4 (5.6)		34.2 (7.0)	

similarity of these four collector designs in many physical and material properties. The greatest differences occur in aperture size (1.8 to 2.7m (5.9 ft. to 8.9 ft.) range) focal length (0.5 to 0.9m) (1.6 to 3.0 ft.) mirror materials (aluminum, film, glass) mirror structure (honeycomb, monocoque, sheet/rib) and tracking and drives. Rim angles, receiver characteristics, concentration ratios and module weight all fall in a very narrow range. The impact of collector properties on performance will be addressed in section 8.2.1.3.2.

8.2.1.2.2 Production and Applications

Approximately 20,400 m^2 (220,000 ft^2) of high temperature line focus concentrators have been produced to date by the three major vendors. Most of the production has been sold to government backed IPH, Heating and Cooling, and Solar Thermal Power demonstration programs. A sampling of these application types and collector operating temperature ranges are summarized in Table 8.2.

As Table 8.2 shows, the longest operating line focus fields have only been in place for three years and the highest operating temperature field (Coolidge, AZ) was dedicated in late 1979.

8.2.1.2.3 Stage of Product Development

The high temperature line focus collector industry is relatively young, has produced about 20,400 m^2 (220,000 ft^2) of collectors to date, has seen evolutionary product changes and is growing at a rapid date. 1980 collector shipments and bookings may well exceed the total produced to date.

A qualitative assessment of technical readiness for various solar technologies has been published by researchers at SERI. The following paragraphs are excerpted from reference 8-51, which was published in late 1978:

> "Low temperature solar heating systems, (<100°C) are currently being manufactured and are available for residential and industrial applications. The performance of these systems is well documented. Current research efforts are directed at improving the efficiencies and reducing the costs of these systems."

TABLE 8.2

LINE FOCUS COLLECTOR INSTALLATION EXAMPLES

APPLICATION	YEAR	LOCATION	FIELD SIZE (000)	VENDOR	COLLECTOR OPERATING TEMP.
Heating & Cooling	1978	White River AZ Indian Hospital	2.8M^2 (30ft^2)	Suntec Hexcel	113°C (235°F)
Solar Thermal Power (Irrigation Pumping)	1977	Gila Bend AZ	.6M^2 (6ft^2)	Suntec Hexcel	154°C (310°F)
	77/78	Willard N.M.	1.3M^2 (14ft^2)	Acurex/ Solar Kinetics	115-215°C (240°F - 420°F)
	1979	Coolidge AZ	2.1M^2 (23ft^2)	Acurex	204-288°C (400°F - 550°F)
Industrial Process Heat	1979	Sherman TX Johnson & Johnson	1.0M^2 (11ft^2)	Acurex	177-215°C (350°F - 420°F)

"Medium temperature solar systems (<150°C) are not as readily available as are low temperature systems. They are, however, being manufactured on a limited basis, and quantities are expected to increase in the near term. Some systems have been installed in working situations and performance data are being developed. Current research efforts are directed at obtaining additional performance data and reducing the costs of these systems."

"Most high temperature solar heating systems (>150°C) are conceptual designs or prototypes. Systems performance and cost have not been proven. Substantial reductions in cost are required before these systems can compete with conventional fuels."

State of Equipment Delivery Systems

"As noted, low temperature solar heating systems are currently being manufactured and are generally available to interested consumers. More than 1,000 firms manufacture these systems and many are listed in the telephone directories of major cities. The delivery system for low temperature applications is new, but maturing, and includes manufacturers, wholesalers, dealers, and installers."

"Similar to low temperature systems, components for medium temperature systems are currently being manufactured, but not on as large a scale. The delivery system for medium temperature systems is not as mature as that for low temperature systems, and these are usually purchased directly from the manufacturer based on buyer's specifications. Medium temperature systems are more sophisticated than low temperature ones and require more preliminary design effort to integrate the system with existing conventional systems."

"High temperature heating systems presently exist as prototypes or are in early conceptual design stages. The manufacture of these systems is highly specialized and currently only for research and development projects. As a result, a delivery system for high temperature systems does not exist yet, and most of the delivery responsibilities are conducted by the manufacturer."

Exxon's qualitative assessment of line focus collector technology is in substantial agreement with SERI's analysis. On a relative basis, line focus technology is less mature than flat plates, more mature than parabolic dishes and central receivers. On an absolute basis, the line focus collector of early 1980 is in the engineering prototype stage of the product development cycle.

8.2.1.2.4 Technology Advances To Date

The line focus collector of early 1980 is quite similar in design and materials to the prototypes which were developed and deployed in 1977. Some of the improvements made in this period in collector technology include the following:

8.2.1.2.4.1 Receiver Coating

The standard black chrome on nickel electroplated selective coating which is commonly used in the flat plate collector industry has been found to degrade in air at temperatures above 250°C (480°F) (8-26). Work at Sandia on modifying plating bath chemistry has produced black chrome formulations 8-27 which are stable in air up to 350°C (662°F) with measured optical properties of $\alpha = .97$, $\epsilon = .31$ (300°C (572°F)). The stable formulation differs from the unstable formulation in plating residence time (5min. v. 3min) and the concentration of trivalent chromium (8g/l vs. 16g/l (1.1 oz/gal v. 2.1 oz/gal)). In addition to Sandia's efforts, work is underway by several researchers aimed at characterizing the structure of black chrome and understanding its composition and degradation mechanisms (8-28,29).

Sandia Labs is currently attempting to develop commercial sources of high temperature black chrome electroplating. They are funding Honeywell to study the relationships among bath plating conditions, coating optical properties and thermal stability and to develop a detailed process handbook for electroplaters. Sandia is continuing to do production studies at Highland plating in Los Angeles in an attempt to determine the differences between inhouse plating under lab conditions and commercially available plating. However, today a commercial black chrome coating for operation above 250°C (480°F) remains unavailable.

8.2.1.2.4.2 Reflector Materials

The polished aluminum reflector materials available today have changed very little in the last three years. Improvements have been made with metallized acrylic films such as 3M's FEK 244 to smooth out ripples caused by a non uniform adhesive layer. These two reflector materials types are found on the majority of installed line focus collector systems. Silvered glass has seen little application to date due to limited availability of curved glass.

8.2.1.2.4.3 Tracking and Drive Systems

Some problems which have been reported 8-30 with shadow band tracking devices and electric motor drives installed in 1977 include: inaccurate and unstable tracking systems requiring manual adjustment to accommodate cloud cover; welding and sticking of relay contacts; and limited motor drive torque. According to suppliers of shadow-band type tracking devices such as Acurex and Solar Kinetics, the operation and reliability has been considerably improved in the last three years. In addition to this type of tracking device which senses the sun directly, devices which sense the reflected solar beam which is incident on the receiver tube have been developed by several companies including Anderson Cornelius and Honeywell. The Anderson Cornelius trackers are installed on 2300 m^2 (25,000 ft^2) of Suntec collectors at a Control Data Corporation facility in St. Paul and the Honeywell trackers are installed at the Yuma and White River Arizona heating and cooling demonstrations. No major problems from either installation have been as yet reported.

Other improvements which have been made in collector drive systems include the use of weather proof housings to protect motors, gear boxes, and control electronics.

8.2.1.2.5 Current Collector Performance And Cost

8.2.1.2.5.1 Performance

A considerable body of test data is available on the instantaneous thermal performance of a number of line focus collector concepts. This data is based on testing done at Sandia Labs CMTF (8-31) for East-West mounted collectors with the sun normal to the collector (peak efficiency) at high insolation levels. This orientation allows the maximum efficiency which can be achieved for a given collector temperature. A limited amount of testing was conducted by Sandia to measure the day long performance of collector modules at selected temperatures in the East-West orientation. For economic reasons, there is very little testing done on single collector modules for periods longer than a day. Collector simulation models are typically employed to calculate performance for periods in excess of one day. The results of two simulation efforts have been published by Sandia Labs (8-25,32) and used a collector model which assumed no end losses and perfect optics and tracking. Simulations were run at low temperatures in various collector orientations using TMY weather data from 26 cities. The Sandia simulation of reference (8-25) is based on actual test results of instantaneous efficiency at normal incidence factored by an annual cosine correction.

The results of the test data and performance predictions described above are shown in Table 8.3 for three operating temperature points, 100°C, 160°C, and 275°C (212°F, 320°F, 527°F) which are typical of STEOR requirements.

TABLE 8.3

LINE FOCUS PERFORMANCE RESULTS

	Sandia Testing		Sandia Simulations Annual Efficiency		
Collector Temperature	Instantaneous Efficiency	Daily E-W Efficiency	Reference 8-32 E-W	Reference 8-32 N-S	Reference 8-25
100°C(212°F)	.55 - .67	-	.49	.55	.45 - .50
160°C(320°F)	.52 - .64	.37 - .42	-	-	.38 - .45
275°C(527°F)	.42 - .56	.35 - .41	-	-	.30 - .37

Albuquerque weather data is used for the simulations, since all testing was done at that location. The range of efficiencies shown in Table 8-3 for the test data cover a number of available line focus collectors with properties as described in Table 8.1. The basis for the efficiency calculation is the direct normal solar radiation. That is, the amount of direct solar radiation which a fully tracking pyrheliometer would measure. Since this was the basis for the test results shown in columns 2 and 3 of Table 8.3, it was also used as the simulation basis. It is more common, however to describe concentrating collector efficiency in terms of direct normal radiation converted to the collector normal plane.

Using the information from Table 8.3 as typical of current technology line focus collector performance, it is seen that for the temperature range 100°C to 275°C (212°F to 527°F) and high insolation areas, annual predicted efficiencies are in the range of .30 to .50. In terms of energy collected in the typical Albuquerque environment this means a range of 860 to 1430 Kwh/m^2-yr (270,000 to 450,000 BTU/ft^2-yr). This, of course, does not include field piping losses or storage losses.

8.2.1.2.5.2 Cost Data

A survey was made of published information relating to collector manufacturers selling prices and actual or estimated installation costs. Results are shown in Table 8.4. Most of the data shown in the table are based on manufacturers and DOE contractors' estimates. Actual project costs are difficult to obtain from DOE since many line focus installations have been either completed in the past year or are in the construction phase. In most cases the final project cost information has not yet been released by DOE. The collector cost shown in Table 8.4 typically includes tracking sensor and controller, drive motor and flexible hose connection. Installation costs are dependent on collector and site and the estimate from reference (8-36) does not break down installation costs. Also, the quantities involved in the estimates are in the 650 to 1860 m^2 (7,000 to 20,000 ft^2) range with the exception of Exxon-STEOR design which is for 23,000 m^2 (250,000 ft^2). The message from Table 8.4 is that for currently available collectors suitable for STEOR application, 215 \$/m^2 (\$20/ft^2) is a reasonable collector FOB price and 75 to 108 \$/m^2 (\$7 to \$10/ft^2) is a reasonable range for installation costs. Cost projections and performance projections are addressed in the next section.

8.2.1.3 Cost And Performance Projections

8.2.1.3.1 Baseline Performance Model

In order to assess the impact of collector design improvements which may be implemented in the 1980-1990 time frame, a computer simulation approach was used. The simulation consists of a line focus collector model which

TABLE 8.4

SURVEY OF COLLECTOR HARDWARE AND INSTALLATION COSTS

YEAR AND SOURCE	F.O.B. COLLECTOR PRICE, $/M^2$ ($/FT^2$)	$/M^2$ ($/FT^2$) INSTALLATION COSTS	TOTAL INSTALLED COST $/M^2$ ($/FT^2$)
1977 ATU Survey (Estimated)(8-33)	150 (14)	-	-
77-78 Willard Project (Actual)(8-34)	-	-	205. (19.)
78 Survey (Estimated)(8-34)	160-236 (15-22)	75-107 (7-10.)	236-344 (22-32.)
79 Foster Wheeler-Dow Project (Estimated) (8-35)	-	-	270-317 (25-29.50)
79 S.W. Research Lone Star Project (Estimated)(8-36)	204-258 (19-24)	21-32 (2-3)	226-290 (21-27)
80 Exxon - STEOR (Estimated)(8-37)	215 (20)	65. (6.) Installation Labor 32. (3.) Site Prep, Footings	312. (29.)

is run in the Albuquerque environment for four clear days near the equinox and solstice points. The four day results are averaged to estimate annual collector performance. The simulation was run at two collector operating temperatures, 120°C (250°F) and 290°C (550°F). The collector model accounts for material and design properties and cosine losses, but neglects transient effects and end losses. A breakdown of the inputs to the baseline simulation run and the annual collector efficiency output is given in Table 8.5. The results show annual efficiencies for the baseline collector of .51 at 120°C (250°F) and .42 at 290°C(550°F). These results are consistent with the testing and simulation results shown in Table 8.3. It is recognized that the annual efficiencies predicted in this way will be on the high side because the insolation level is high and collector efficiencies increase with insolation level. However, this simulation approach, as will be detailed in the following paragraphs, will lead to conservative predictions of collector performance improvements.

8.2.1.3.2 Performance Improvements

A number of collector improvements currently in the research and development stages were assessed to determine their impact on collector performance. The improvements are briefly summarized in the following paragraphs:

8.2.1.3.2.1 Reflector

One of the key elements in improving performance and durability for line focus collectors is the back silvered glass reflector. Glass has excellent environmental durability and silver has the highest solar specular reflectance of any material. A considerable amount of R&D activity is currently being devoted to developing parabolically curved glass mirrors by several approaches. These include thermally sagging either by gravity into a mold or by hot mechanical pressing techniques. Another approach is to use thin flat glass which has been chemically strengthened to withstand high stress or to laminate the glass to a metal substrate, then in either case, to elastically deform the flat glass into a parabolic shape. In addition to line focus related R&D, which is summarized in reference (8-39), there is considerable R&D activity directed at silvered glass for heliostat applications. The scope of this R&D effort can be seen by referring to the recent SERI sponsored workshop (8-40) devoted entirely to reflective materials. Over 35 technical papers dealing with silvered glass and other materials were presented.

As reported in reference 8-25, the specular reflectivity for thin, silvered glass can be up to .95 compared to .81 for polymeric films and .75 for anodized aluminum. Potential primary sources of glass mirrors include Ford Motor Co., PPG Industries, and Corning Glass. Potential secondary sources of glass mirrors include line focus collector vendors such as Solar-Kinetics, Suntec, Acurex, and M.A.N. of The Federal Republic of Germany (FRG). Although the level of development activity is high, it is anticipated that about two years additional development is required to move

TABLE 8.5

BASELINE COLLECTOR PERFORMANCE DATA

INPUTS

- Environmental: Albuquerque weather data for 3/15, 6/22, 12/21, 1962 from Reference 15.

- Collector Material Properties

Mirror reflectance	=	0.81
Glass transmittance	=	.90
Coating absorptance	=	.93
Coating emittance	=	.15 (120°C) (250°F)
	=	.25 (290°C) (550°F)

- Collector Design Properties

Aperture	=	2 meters (6.6ft)	Receiver Intercept Factor = .93
Rim Angle	=	90°	Collector Orientation = North-South
Receiver Diameter	=	3.17 cm (1.2 in.)	
Glass Shroud Diameter	=	5.7 cm (2.2 in.)	

OUTPUT

- Annual Collector Efficiency (η) Based on Direct Normal Insolation

η = .51 @ T=120°C (250°F)

η = .42 @ T=290°C (550°F)

glass reflectors from the R&D stage to commercial availability. The impact of silvered glass reflector on line focus collector performance is described in paragraph 8.2.1.3.2.5.

8.2.1.3.2.2 <u>Anti Reflection Films</u>

. Another performance improvement technique which was considered in this study is the use of surface treatments or anti-reflection coating to reduce the surface reflection of the transparent shroud which typically surrounds the receiver pipe. Average values of solar transmission through glass shrouds are around .90. The modification of the surface to reduce reflection losses could result in .96 solar transmission. Honeywell (8-41) under DOE funding has done considerable investigation of acid etching and anti-reflection films as two approaches to reducing surface reflections. The Honeywell program has achieved increased transmittance in lab environments and is currently addressing the durability and producibility of the processes. Other R&D activity in this area is being conducted by Owens-Illinois (8-42), Hughes Aircraft (8-43) and Springborn Labs (8-44).

Because of the applicability of this improvement to most low and medium temperature solar collectors, and the current level of industry R&D, this technology is expected to move from R&D to commercial availability in 4 years.

8.2.1.3.2.3 <u>Receiver Coatings</u>

Black chrome is receiving considerable R&D funding as it moves closer to commercial availability. A key technical hurdle still remains which is the production of thermally stable (up to 350°C) (662°F)) coatings by commercial electro platers. Stable coatings have been produced in the lab by Sandia and both Sandia and Honeywell are active in black chrome process development. A slight improvement in solar absorptivity is expected when high temperature black chrome moves into the production phase and the process is better controlled. The timing is expected to be in the next two years and the improvement is expected to be from .93 to .96 with no change in emissivity (.15 @ 100°C (212°F) .25-.30 @ 300°C (572°F)). Commercial electroplaters such as Highland and Olympic/ National are potential sources of high temperature black chrome.

A potential alternative coating to black chrome is black cobalt which is under investigation by SERI and Dornier (FRG).

8.2.1.3.2.4 Evacuated Receiver

The effect of vacuum on receiver heat loss for line focus collectors has been studied by Ratzel 8-45 who has calculated receiver heat loss reductions of up to 50% when the space between the receiver and the glass tube is evacuated. The current design basis for the Sandia Labs Trough Development project (8-25) is the use of a sealed but unevacuated receiver. Thus the R&D activity for an evacuated line focus receiver is small, but the related development work in vacuum tube receivers for non-concentrating and low concentrating collectors is considerable and includes G.E., Owens-Illinois, Corning, Philips and Sanyo.

An evacuated receiver assembly for line focus collectors could be available by 1985.

8.2.1.3.2.5 Heat Mirror

The use of an infra-red reflecting film to reduce thermal radiation losses was also examined. Materials such as tin-oxide and indium tin oxide are candidates. These materials are typically vacuum deposited and although not being pursued actively for line focus improvements, they are being applied in photovoltaic applications as transparent electric conductors.

One characteristic of a heat mirror, unlike the previously described improvements, is a simultaneous reduction in the collector optical efficiency with a reduction in the receiver thermal loss. The net impact on collector efficiency could be negative, depending on temperature. This effect is quantitatively described in 8.2.1.3.2.7.

Philips Research Lab of FRG (8-46) is one company investigating IR reflectors for use in thermal collectors.

If heat mirror technology becomes commercial for line focus collectors, the probable time frame would be 1984-86.

8.2.1.3.2.6 Improved Concentration Ratio

If line focus concentrator error budgets can be reduced from current technology, then higher concentration ratios and lower receiver heat losses can be achieved. For this study the performance impact of reducing receiver tube diameter from 3.2cm (1.25 in) baseline to 2.5cm (1.0 in) was studied.

Significant increases in concentration ratios for parabolic line focusing collectors are not expected to occur because of the probable high cost penalty. A reduction in tracking, alignment, and mirror slope errors, which are the largest error sources in line focus collectors, must come through a tightening of manufacturing and assembly tolerances. This is difficult to achieve with minimal cost penalty. Some improvements, however are expected from the line focus collector vendors under the driving force of DOE procurements such as the recent low cost line focus collector PRDA (8-47). The source of such improvement would be the line focus industry and the timing is seen as 1984-86.

8.2.1.3.2.7 Summary Of Improvements

The above described improvements, their properties, sources and timing are summarized in Table 8.6. The impact of each improvement on collector performance using the Exxon comupter model in the Albuquerque environment is summarized in Figure 8.4.

Figure 8.4 shows the increase in annual collector efficiency compared to the baseline line focus collector whose properties have been described in table 8.5. Seven cases are shown for each of two operating temperatures, 120°C and 290°C (250°F and 550°F). The baseline collector performance at these temperatures is .51 and .42 respectively. In Figure 8.4 the baseline efficiency is set equal to 1.0. The largest increase in efficiency is due to the improved reflector (1.21 and 1.19) with improved glazing next (1.10 and 1.08), followed by evacuated receiver (1.10 and 1.06), higher concentration ratio (1.05 and 1.02) and improved coating (1.04 and 1.03). The heat mirror shows a .06 decrease in efficiency at 120°C (250°F) and a 1.03 increase at 290°C (550°F).

In Figure 8.4 the assumption is made of the combination of all improvements excepting the heat mirror, and figure 8.4 shows a potential improvement in efficiency of 1.35 (to .69) at 120°C (250°F) and 1.50 (to .63) at 290°C (550°F). These relative improvement numbers are conservative because they are based on clear days in Albuquerque which is a high insolation area which yields high efficiencies. (Since Albuquerque is already a high absolute performance area, its relative improvements are smaller. In a lower absolute performance area, the relative improvements would be larger, and thus Albuquerque relative improvements are conservative predictors). A related study done by SERI (8-48) shows individual performance gains of 20% to 40% for techniques including evacuated receiver, silvered glass and reduced concentrator errors. The baseline performance is not described explicitly in the SERI study, but the prediction method is based on long term average collector performance at specified locations.

A key point here is that concentrators of today are performing well under their potential and that performance gains resulting from ongoing R&D have the potential to increase annual performance by 50% over the next five years. The cost of such improvements will be addressed in the next section.

TABLE 8.6

PROJECTED TROUGH PERFORMANCE IMPROVEMENTS

IMPROVEMENT	PROPERTY CURRENT	 IMPROVED	PROBABLE AVAILABILITY	POTENTIAL SOURCES
SILVERED THIN GLASS REFLECTOR	ρ=.81 (FILM)	ρ= .95	1981-82	CORNING FORD PPG
A/R GLAZING	τ=.90 (GLASS)	τ=.96	1983-84	CORNING OI HONEYWELL HUGHES
EVACUATED ANNULUS	CONDUCTION LOSS	CONDUCTION ELIMINATED	1984-85	CORNING, OI GE SANYNO, PHILIPS
SELECTIVE COATING	α=.93 (BLACK CHROME) ϵ=.25 (300°C) (572°F)	α=.96 ϵ=.25 (300°C) (572°F)	1981-82	ELECTRO-PLATERS
HEAT MIRROR	τ=.90 ϵ=.25	τ=.84 ϵ=.07 (300°C) (572°F)	1984-86	GLASS VENDORS PHILIPS INDIUM CORP.
REDUCED CONCENTRATOR ERRORS (HIGHER CONENTRATION RATIO)	DR=3.2CM (1.3 IN) INT=.93	DR=2.5CM (1.0 IN) INT=.93	1984-86	TROUGH VENDORS

8.2.1.3.3 Collector Cost Projections

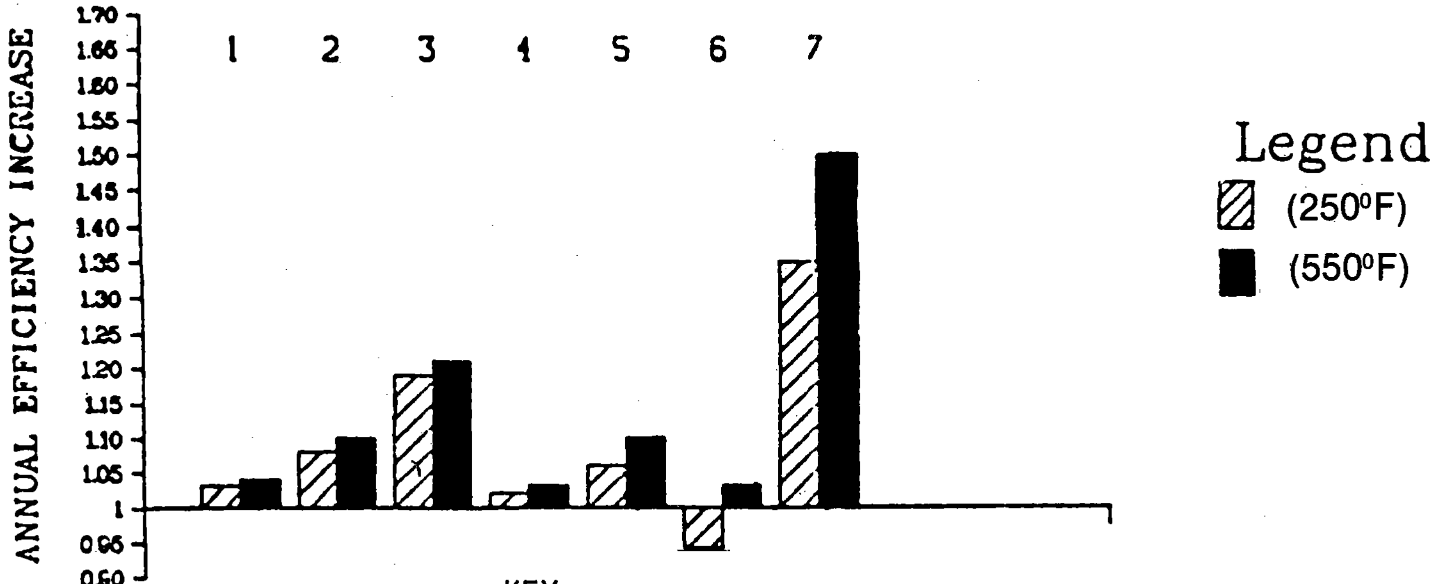
8.2.1.3.3.1 DOE Cost Goals

Several references were consulted to determine the goals and timing of government funded development and demonstration activities in the 300°C (572°F) line focus collector area. These include the Sandia Labs Trough Development program (8-49), DOE installed collector cost goals (8-50) and the recent line focus mass produced PRDA from ref. (8-47). All share the common goal of collector cost reductions over the next 2-10 years through production-related design improvements and increases in sales volume. Table 8.7 summarizes these DOE cost goals and their timing. The ultimate installed line focus collector cost goal from Table 8.7 is 107 $/m^2$ ($10/ft^2) at an unspecified volume which represents a mass production scenerio. Certain underlying assumptions concerning collector performance and durability are included in the DOE cost goals. For example the performance goal of the Sandia Trough Development project is peak noon collector efficiency of 60-70% at 300°C (572°F). The goal of the mass produced PRDA is 65% @ 300°C (572°F) and 71% @ 200°C (392°F). Both sources assume collector durability will increase to 15-20 year lifetimes.

8.2.1.3.3.2 Cost of Performance Improvements

The collector performance improvements outlined in section 8.2.1.3.2 could result in annual collector efficiencies in the range of 63% at 292°C (550°F) and 69% at 120°C (250°F). Since this is fairly consistent with a peak noon efficiency of 70% @ 300°C (572°F), it could be argued that these improved performance levels are already factored into the DOE cost goals. However the ultimate collector cost goals of $107/m^2 ($10/ft^2) installed leaves little margin for non standard parts or processing. If an assumption of $21/m^2 ($2/ft^2) is made for high volume collector installation costs, then $86/m^2 ($8/ft^2) would remain as the cost goal at the collector manufacturer F.O.B. point. This price would seem to require all collector materials to cost in the range of $20-30/m^2 ($1.9-$2.8/ft^2). It is expected that improvements such as better coating and higher concentration ratio will not add to the collector cost goals because they are incremental improvements which should be made as the volume increases and designs are improved. Similarly, the cost of a silvered glass reflector in mass production is essentially the cost of the processed glass, since very little silver or exotic adhesives are involved. This element is assumed to be included in all DOE cost goals. The cost of an evacuated receiver assembly should add to the ultimate cost goals due to the inclusion of bellows seals, a vacuum getter and automated evacuation and bonding processes. The additional cost over unsealed receivers could be in the range of $5./m^2 ($0.5/ft^2) of aperture. The additional cost of anti-reflection films on both surfaces of the glass shroud could add $5/m^2 ($0.5/ft^2) receiver area or about $.21 to 54/m^2 ($.02 to $.05/ft^2) of aperture.

PREDICTED TROUGH PERFORMANCE IMPROVEMENTS



KEY

BASELINE
TROUGH
EFFICIENCY
51% @ 120°C (250°F)
42% @ 290°C (550°F)

1. IMPROVED COATING α=.96 (.93)
2. A/R GLASS τ=.96 (.90 = BASELINE)
3. SILVERED GLASS ρ=.95 (.81)
4. HIGHER CONCENTRATION DR =2.5CM (3.2CM)(1 in (1.3 in)
5. VACUUM RECEIVER (AIR)
6. HEAT MIRROR τ =.84, ϵ =.07 (.90, .25)
7. 1 THROUGH 5 COMBINED

FIGURE 8.4

Marking these costs up to the manufacturers' FOB level, an additional \$16-21/m^2 (\$1.5 to \$2.0/ft^2) is indicated for the evacuated receiver assembly and an additional \$.64 to \$2.15/m^2 (\$.06 to \$.20/ft^2) for the A/R coating. From Figure 8.4 the predicted performance improvements for evacuated receivers is 10% and for the A/R coating is also 10% at 290°C (550°F). Thus, it would appear that based on collector FOB cost goals of \$86/m^2 (\$8/ft^2), the A/R coating would be cost effective while the evacuated receiver would not be. The more likely situation is that those performance improvements and their indicated costs could be realized well in advance of the achievement of the overall collector cost goal. For example, a 10% performance improvement based on \$323/m^2 (\$30/ft^2) installed collector system could cost up to \$32/m^2 (\$3/ft^2) and still be cost effective.

8.2.1.3.3.3 Collector Subsystem Cost Projections

Two approaches were taken to estimate collector cost projections. The first approach begins with 1980 vendor cumulative production levels and selling prices and projects collector prices based on a learning curve assumption of 85%. The second approach was to estimate the ultimate weight of line focus collectors after redesigns for mass production and to scale up to a manufacturers' FOB price with some assumptions on cost per unit weight.

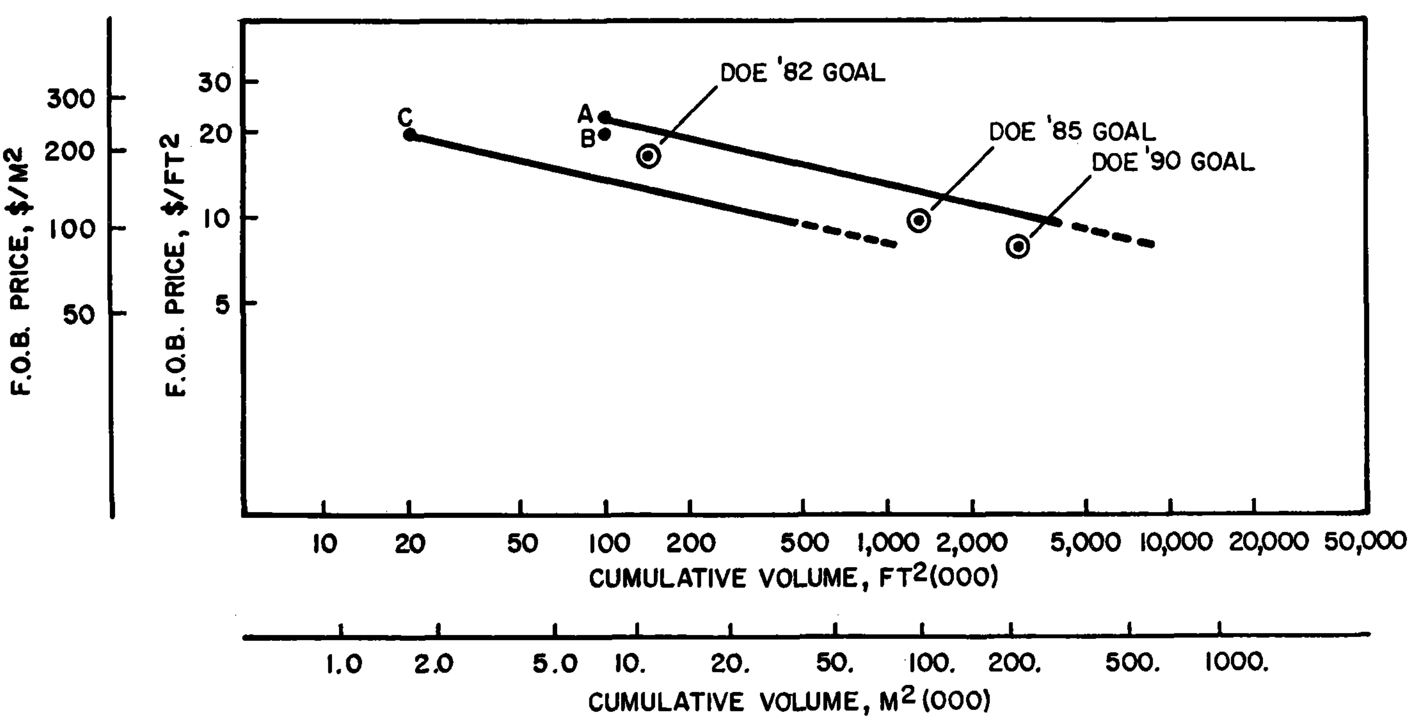
The first approach is illustrated in Figure 8.5 which shows approximate collector production to date (absicca) and approximate 1980 selling prices (ordinate) for three line focus collector vendors shown as Vendor A, B, and C (Suntec, Acurex and Solar Kinetics).

The previously noted learning curve rate is assumed to bound future improvements for each vendor. A composite average vendor range is then illustrated. The learning rate is assumed to be typical of manufactured hardware similar in complexity to line focus collectors. Also indicated on Figure 8.5 are the DOE 1982,1985 and 1990 cost goals for collector subsystems from Ref. 8-50. An assumption of \$21.5/m^2 (\$2/ft^2) was made for the installation costs to arrive at the 1982 goals for collector FOB prices of \$183/m^2 (\$17/ft^2) and the 1985 goal of \$107/m^2 (\$10/ft^2). We also assume that both goals should fall in the middle of the two limiting learning curves. This placement determines the cumulative volume required to meet the '82 goal, of about 13,000/m^2 (140,000 ft^2) for each of three vendors. To meet the '85 DOE cost goal, a combined industry volume of 0.3-0.6 million m^2 (3-6 million ft^2) is indicated. In order to meet the 1990 DOE goal of \$107/m^2 (\$10/ft^2) installed or \$86/m^2 (\$8/ft^2) collector FOB, Figure 8.6 indicates an industry volume of 0.8 million m^2 (8.3 million ft^2).

TABLE 8.7

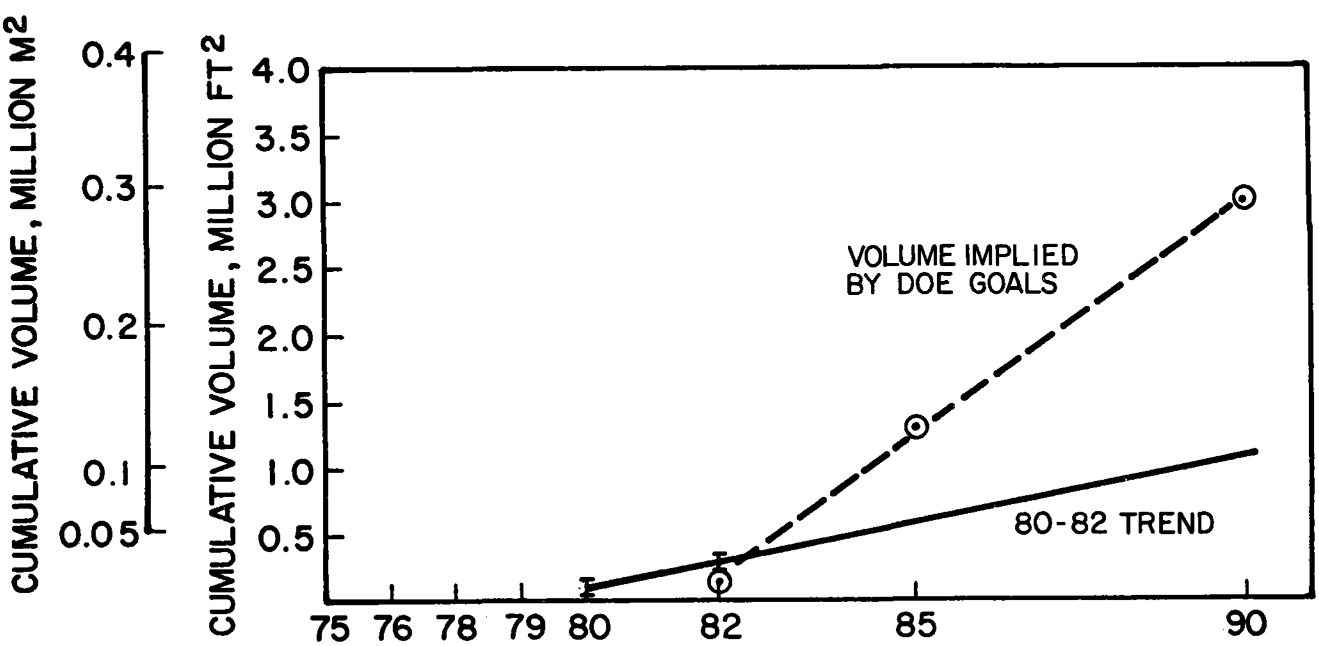
SUMMARY OF DOE COLLECTOR COST GOALS, 1980 DOLLARS

SOURCE	COST GOALS $\$/M^2$ ($\$/FT^2$) (YEAR)	NOTES
DOE Program Summary (Ref. 8-50)	\$204 (\$19) (1982) \$129 (\$12) (1985) \$107 (\$10) (1990)	Installed Collector Costs
Sandia Development Project (Ref. 8-49)	\$107-214 (\$10 - \$20)	Production Prototype Ready 1982
DOE Mass Produced PRDA (Ref. 8-47)	\$107 (\$10) (1985)	Installed Collector Cost



LINE FOCUS COLLECTOR PRICES VS. VOLUME
(PER VENDOR, THREE EQUAL SHARES)

FIGURE 8.5



LINE FOCUS COLLECTOR VOLUME VS. TIME
(PER VENDOR, THREE EQUAL SHARES)
FIGURE 8.6

Another indication of the ultimate price of mass produced line focus collectors can be determined from weight-cost considerations. Line focus collectors of 1980 range in weight from 20 to 30 Kg/m^2 (4 to 6 lb/ft^2). Assuming design modifications which lower the collector weight to 12 to 15 Kg/m^2 (2.5 to 3 lb/ft^2), and using \$2.20/Kg (\$1/lb) as a rule of thumb for primary material costs, such as glass and steel then a collector material cost of \$27 to \$32/m^2 (\$2.5 to \$3.0/ft^2) and a collector FOB price of \$80 to \$130/m^2 (\$7.5 to \$12/ft^2) (three to four times cost) would seem probable in a high volume situation.

8.2.2 FLUID SYSTEM IMPROVEMENTS

Cost reductions are expected to occur in the fluid piping portion of line focus process heat systems due to design optimizations which result in minimum annual cost (capital plus operating) considering the following variables:

- o Insulation size, cost and heat loss
- o Piping size, cost v. pumping cost
- o Field layout design for a given collector array.

These and other variables were addressed in a field layout study performed by Jacobs engineering for Sandia Labs. The study has not yet been released but an interim report was obtained and the following preliminary recommendations were extracted. These include:

- o Thicker insulation than conventional process piping
- o Thinner piping wall
- o Lower conductivity, low mass thermal insulation
- o Longer collector T strings up to 45m(480 ft.)
- o Longer span for field piping supports
- o Use of bellows in place of pipe for thermal expansion

Assuming most of these recommendations could be implemented in solar - IPH system, the following cost reductions may be realized. These reductions are based on the Jacobs study and are relative comparisons of their optimum design point with their off optimum points. (Solar energy cost is \$9.4/10^9J (\$10/MBTU). The off optimum points do not necessarily represent current piping practice, but in the absence of standards for solar - IPH fluid systems, provide a basis for cost comparisons. The following percentage cost savings are indicated based on annualized capital and operating costs.

- o Optimizing insulation thickness - 26% Savings
- o Lower cost, low mass insulation - 22% Savings
- o Optimizing field piping layout for fixed collector array area - 12% Savings
- o Longer T strings - 17% Savings (46000 m^2 (495,000 ft^2) array)
  - 12% Savings (4600 m^2 (49,500 ft^2) array)
- o Reduced number of pipe supports - 70%

Taken together these improvements could reduce the annual cost of the entire fluid subsystem by about 20%. The impact of these improvements on total system costs is addressed in paragraph 8.2.7.

8.2.3 FOUNDATION IMPROVEMENTS

Line focus collector systems require support foundations for the pylons located between each mirror module. Besides supporting the dead loads of the collectors, the foundations must resist live loads such as overturning moments and reactions which will occur during periods of severe winds.

As reported by Sandia Laboratories, early collector field foundations evidenced conservative design approaches. Since neither specific design codes nor experimental data about collector foundation survivability existed, the practice of overdesign with its resultant high costs was occuring. A calculation based on references (8-49) and (8-52) would suggest that early foundations (cylindrical reinforced concrete piers) may have cost as much as $67 per square meter ($6/square foot) (assuming 5.6 sq. meter (60 sq. foot) reflector modules). Such a foundation would have employed about 1.53 cubic meters (54 cubic ft) of reinforced concrete in an augered hole 2.44 meters (8 feet) deep. As a result of Sandia's studies, they now suggest that foundations costing less than $11/square meter ($1/square ft) may be obtainable in areas with "good" soil conditions.

These Sandia findings have been based upon analytical studies, wind tunnel load tests and destructive field testing. As a double check upon these results, Foster Wheeler Development Corporation has also considered the problem (8-53). The Foster Wheeler approach was based upon an examination of 3 wind load estimation appraches, representative parametric soil properties and four foundation design concepts. Their conclusions suggested that the loads should be based upon "Reduced Winds Loadings" per the Uniform Building Code (Miscellaneous Structures, - 2 - Section 2311h), and that a double pier plus beam method would provide the minimum cost foundation, estimated at about $17.64/$m^2$ ($1.64/$ft^2$). If a single pier design were specified, the cost would be about $22.70/$m^2$ ($2.11/$ft^2$). A comparison of Sandia and Foster Wheeler results for the single pier case, is as follows:

	FWDC	SANDIA
Diameter M (ft)	0.4 (1.3)	0.4 (1.3)
Length M (ft)	2.8 (9.2)	1.6 (5.2)
Volume M^3 (ft^3)	0.40 (14)	0.23 (8)
Installed Cost/M^3 (ft^3)for Concrete	\$515 (\$14.6)	\$196 (\$5.6)
Other Costs	\$ 51	\$ 37
Cost/M^2 (ft^2)	\$22.70(\$2.11)	\$ 9.04 (\$0.84)

Notes:

1. Sandia Report 79-7016, May 1979, Table 4, typical site, standard load.
2. FWDC letter January 31, 1980, UBC reduced wind, 1 drive support and 4 non drive supports averaged together. (Appendix C)

Compared to a 1.53 cubic meter (54 cubic foot) baseline, the percentage reductions in concrete suggested by FWDC or Sandia range between 75% and 85%. The corresponding cost savings are on the order of 70% to 80% (using the FWDC costing basis). These represent substantial savings on this subsystem compared to early designs.

Further reductions seem unlikely for this conventional technology, beyond those achieved through the application of appropriate codes. For example, it is likely that several crafts will be involved in any installation of poured concrete foundations including: carpenter, iron worker, laborer and equipment (auger) operator. Thus, a four-to-five man crew can be expected. Given the likely increased need to insure proper alignments (resulting from drive string lengths approaching 49 meters (160 feet), the pacing step in this operation is likely to remain alignment and augering. Recent experience would suggest one-to-two footings per hour (and a five man crew) as representing realistic productivity levels (8-54). If augering is the pacing step, then single pier foundations are favored over double prior systems.

8.2.4 CONTROL SUBSYSTEM

The short history with installed line focus systems has seen system-level controllers which are simple, limited function devices. Typically, a single system controller is wired to the local collector controllers (one local controller per drive string). The system controller senses insolation level and wind speed and actuates the local controllers which drive the individual collector rows until overridden by the system controller.

To date, problems have been encountered with the tracking sensors in the local controllers and the sensor package - data acquisition systems. System level control problems have been minimal, due either to their simplicity or their manual override features.

Future trends in IPH systems will dictate the nature of system level controls. One is a reduction in the data acquisition requirements as systems move from experimental to commercial. The other trend is toward larger systems to realize greater economies of scale and displace larger fractions of conventional fuels. These two trends will probably require future control systems to have some data acquisition and processing capability, and the ability to provide collector status and maintenance information to a central control panel. Communication capability, whether RF or digital, will also allow individual collectors to receive tracking signals from a central clock which can result in increased energy collection on partly cloudy days over local tracking schemes which interrupt collector motion during cloudy periods. An estimate of the cost of future system level controls is made in 8.2.7.

8.2.5 OIL FIRED STEAM GENERATOR SUBSYSTEM

Four major areas are currently being investigated for improvements to the efficiency and operating costs of oil fired steam generators. As progress in these areas tends to be regarded as confidential by boiler manufacturers, little additional detail can be provided to the following descriptions of the areas of improvement (8-55). The areas under investigation are:

- Designs that allow the use of dirtier water (or reuse of produced water) with minimal treatment, thus reducing treatment and water costs and water disposal problems.

- Efficiency improvements from a closer monitoring of stack gas composition which will allow boiler operation with optimal quantities of excess air.

- An increase in steam generator capacity. Increases in the size of steam boilers lead to economies of scale where portability is not of great importance. Larger steam generators are particularly appropriate for steam drive (as opposed to steam simulation) operations.

- The use of low temperature convection sections. These enhance the efficiency of the steam generator by further cooling the combustion gases in the convection section. With low temperature convection systems, it is no longer necessary to preheat the boiler feedwater before its entry into the convection section.

The use of low temperature convection sections may lead to a 6 percent improvement in steam generator efficiency (8-56). As the flue gas temperature will fall below the SOX and NOX dew points, the low temperature section is coated with ceramic material to guard against acidic corrosion. At present this technology is untried, however a rapid payback (1 year) is anticipated.

It should be noted that if low temperature convection sections are employed, it is more difficult to effectively use solar energy to preheat water to 250°F. In these circumstances heating to higher temperatures would be more appropriate; the solar preheated water would be injected directly into the radiant section of the boiler. The pace of these improvements to oil fired steam generator performance will depend upon particular applications.

8.2.6 SYSTEMS INTEGRATION

At the overall systems level, there are several opportunities for cost reduction. For example, the repeated use of a standardized modular design (e.g a 4600 to 9300 square meter (50,000 to 100,000 square foot) system module) would permit the amortization of the bulk of engineering design costs over many installations. Sandia Laboratories has already been active in this area and is planning designs and field testing (8-57). If one assumes that current design engineering costs represent an amount on the order of 1/5 to 1/10 of the total price of the application (including all costs from initial conceptualization to turnover to the operator), and if the construction phase costs $500-$750 per square meter ($46 to $70 per square foot), then engineering design charges can be expected to add $50-$150 per square meter ($4.6 to $13.9 per square foot) to the turn key price. If, however, one modular design were used for say 10 installations, then the per project design engineering charge could be reduced to $11 to $16 per square meter ($1 to $1.50 per square foot).

A second systems level opportunity can be found in the exploitation of large, (and also geographically concentrated) markets. Large (93,000 square meter (1,000,000 square foot)) installations can offer several benefits relative to today's systems. The first is the availability of raw materials in bulk quantities. The second is the opportunity to piggyback jobs in the same area and to obtain some "learning benefit" with subcontractor crews. The third is the opportunity to do local or on site collector fabrication. The objective would be to tradeoff increased manufacturing costs to save on transportation charges. For small order quantities, the penalty of using shipping rates based upon physical volume limitations versus gross weight limitations is small. At the 93,000 square meter (1,000,000 square foot) order level, the level of shipping costs may suggest on site assembly and fabrication.

The final topic at the systems level is the fossil-boiler interface. If one assumes that the field operators will desire to have an independent fossil steam source regardless of solar size, then the solar portion can interface in three ways:

1. Series (a preheat-only alternative)
2. Parallel (a self contained system)
3. Series-Parallel (our baseline system)

On thermodynamic grounds, the series approach (preheat only) will provide the most energy per unit area of collector. The series hybrid system with feedwater storage will be more efficient than the parallel based hybrid options, as long as boiler firing efficiency stays relatively constant at various firing rates. This type of system with storage should eliminate diurnal steam flow variations (due to varying the fossil backup) and would avoid the possibility of incurring any associated costs for downhole equipment repairs should they occur due to periodic variations in steam flow. On an overall cost per unit aperture area basis the series approach will show a higher percentage for storage costs when compared to our baseline series--parallel system. This is because the 121°C (250°F) limit on boiler feedwater will limit the solar input to about 18 to 20% and will thus limit aperture area. For series--parallel, the same tankage costs will be spread over a larger aperture keeping per unit costs lower. A series system will have lower per unit pipe insulation costs than the parallel options reflecting the transport of hot water vs steam. Series systems which use lower temperatures should have lower fluid subsystem maintenance costs. The choice between interface (1) series, and (3) series--parallel will depend on the balance of factors including: need for solar steam; land available; cost of solar equipment; temperature of reused produced water; etc.

Section 8.2.5 briefly outlined the options for improvements for the oil fired fossil boiler. The presence of a viable, low cost, low temperature convection section will tend to reduce the role for solar preheat-only systems. The impact upon solar would be a requirement to increase preheat temperatures to retain the same solar fraction. This option will reduce relative cost effectiveness when compared to a case without the low temperature convection section. Other oil fired boiler improvements will have little cost impact upon solar, as they are unlikely to change the state points where solar will input to the system. Reductions in capital costs will have marginal impact, since fuel is the predominant cost component in the fossil boiler system.

8.2.7 PERFORMANCE AND COST PROJECTIONS

8.2.7.1 Estimates Of Cost And Performance For 1981

For purposes of this section, we assumed that the baseline flash separator preheat hybrid system (23,234 M^2) (250,000 ft^2) and an alternate preheat-only system of 9,294 M^2 (100,000 ft^2) were representative of the range of costs and performance which would be available to operators in 1981. We have used the Task 1, initial systems analysis and other early tradeoff study estimates as our basis (1979 year end prices) (8-58).

	Cost \$/M^2 (\$/ft^2)		Performance MWH_{TH}/YR (10^9 BTU/YR)	
Baseline Steam	\$552	(\$51)	18,760-19,640	(64 - 67)
Alternate Preheat	\$507	(\$47)	9,670-10,260	(33 - 35)

(Cost Estimates are ± 20%)

These estimates assumed a collector such as the one made by Suntec, but without a glass reflector. Foundations, piping, etc., were assumed consistent with current practices plus estimating conservatism. Collector costs represented about \$215/sq. meter (\$20/sq. foot) (F.O.B.) site in both cases. The subsystems level cost breakout was approximately (before owner's charges or contingency):

Installed Subsystem	23,234M^2 (250,000 ft^2) Flash Separator Preheat Baseline		9,294M^2 (100,000 ft^2) Preheat-Only Alternate	
Collector	\$314/M^2	(\$29.2/ft^2)	\$319/M^2	(\$29.6/ft^2)
Pipe & Insulation	104	(9.7)	43	(4.0)
Elect. & I&C	83	(7.7)	81	(7.5)
Pumps & Tanks	12	(1.1)	18	(1.7)
Misc.	12	(1.1)	18	(1.7)
Home Office	27	(2.5)	28	(2.6)
Total	\$552/M^2	(\$51.3/ft^2)	\$507/M^2	(\$47.1/ft^2)

The two system concepts costs were very closely matched. The steam system's piping and insulation costs were higher due to its increased pressure and temperature requirements demanding thicker pipe walls and insulation. Miscellaneous and pumps and tankage subsystems costs were slightly lower for the steam system, since the same equipment was being ratioed over the larger aperture of the steam system. The other costs showed insignificant estimating differences.

Measured in terms of as energy capacity charges (before taxes or incentives), the preheat system was less expensive:

Alternate Preheat:	$4030-$4270/KW_{th}$	($135 - $143/MBTU-YR)
Baseline Steam:	$5720-$5990/KW_{th}$	($191 - $200/MBTU-YR)

8.2.7.2 Estimates Of Future Costs

Table 8.7.A, summarizes the expected impact of the cost and performance improvements which we have discussed previously. We allocated all of the performance improvements to the collector subsystem. Thus, we assumed that the improvements in piping and controls should be treated as their equivalent cost reductions only. We consider that the table represents a conservative forecast on a technical basis; breakthroughs are not required. The changes depend primarily upon increased sales volumes to justify addition of features and amortization of high development costs.

8.2.7.2.1 1990 Cost Projections

Collector costs follow the learning curve (Figure 8.5) discussed in section 8.2. For 1985, we assumed that the average vendor cost would be based upon cumulative shipments of 37,175 square meters (400,000 sq ft) or $140/M^2$ ($13/ft^2$). By 1990 we projected $108/M^2$ ($10/ft^2$), assuming cumulative volume per vendor would have reached 120,818 square meters (1,300,000 sq ft). Figure 8.6 illustrates the assumed 1980-1982 trend line which was used to estimate these cumulative production volumes. This trend lies below the DOE implied volume goals.

Foundation and installation costs showed reductions from the levels in our "1981 estimates". Foundations costs fall to the level estimated by Foster Wheeler for designs which assume the Uniform Building Code's reduced wind loadings. Installation labor savings reflected estimates for modules other than the Suntec design. The other manufacturers modules are currently shipped in a higher state of assembly; these manufacturers substitute lower factory labor costs for higher field labor charges.

Table 8.7.A

Projected Improvement For Baseline Steam Raising System
(Assuming a January 1980 Foster Wheeler Estimate)

Subsystem	Performance (% of 1980) 1980	1985	1990	Cost-$/SQ M ($1980) 1980	1985	1990	Change In Cost 1980-1990
Collector	100%	150%	150%				
FOB Mfr.				$215.3	$139.9	$107.6	$107.7
Foundation				34.4	26.9	21.5	12.9
Install.				64.6	48.4	32.3	23.7
Site				2.2	10.8	10.8	
Fluids (Pipe)	See Text			104.4	93.6	82.9	21.5
Elect	No Change			31.2	31.2	31.2	-
I&C	See Text			51.7	40.9	25.8	25.9
Pumps/Tanks	No Change			12.9	11.8	11.8	1.1
Misc	No Change			9.7	8.6	8.6	1.1
Design Costs	No Change			26.9	20.5	17.2	9.7
Total	100%	150%	150%	$553.3	$432.7	$349.8	$203.5
		($/sq ft)		($51.4)	($40.2)	($32.5)	($18.9)

Notes: Assumes good site with utilities available and no contingency or owners engineering charges. Installation cost savings due to increased sizes and better designs. I&C represents 50% savings from maturity. Design costs are 5% of other costs. For preheat only systems at Edison, see Table 1.7 (which uses an Exxon Engineering estimate basis. See Table 6.6 for a sample reconciliation of Exxon and Foster Wheeler estimates).

Piping and insulation costs are projected to fall by about 20 percent. For ease of computation, we have treated the 20% cost effectiveness improvement (discussed in section 8.2.2) as a pure cost saving. This was reasonable because any efficiency gain we assumed would have been reflected in a reduced area of collectors per unit energy output. For simplicity, we credited this marginal collector cost savings to the fluid system and showed our results per unit area.

The control subsystem price is projected to drop by up to 50%. The most important reduction should come from lowered requirements for special instrumentation, data acquisition and data processing capacity found in the current generation of pilot systems. Secondary reduction components should include savings due to amortization of control system design costs and hardware cost reductions resulting from increased cumulative production and larger system sizes. Some minor cost savings may also be expected from performance improvements in control subsystem tracking accuracy.

We assumed that design costs should be about 5% of total non-design charges. The absolute engineering dollar cost per unit area should be reduced by about 36% as other costs decrease. New modular designs should not substantially change this projection because of their assumed multiple applications. Costs of standard process equipment such as tanks, pumps, electrical and miscellaneous will not change. This finding assumes that only standard fluids (water) would be used and that exotic storage techniques would be unavailable.

8.2.7.2.2 1985 Cost Projections

The collector F.O.B. cost was estimated from our learning curve (Figure 8.5). All other costs (except design engineering at 5% of total other costs) were linearly interpolated between the 1980 and 1990 values. Site costs for 1985 were increased to be more representative of general site utilities needs.

8.2.7.2.3 1985 And 1990 Performance Projections

1985 collector performance is presumed to be increased by the full 50% as suggested by Section 8.2. This assumption was based on discussions with vendors regarding their development plans and the timetable for engineering development of line focus collectors by Sandia. As in collector price reductions, the major driving forces are current sales volume and projected sales growth sufficient to justify tooling costs and to attract subtier suppliers. Since preheat-only systems are already more efficient, (due to lower temperatures), the effect of our forecast improvements is to raise their relative performance by about 35% (section 8.2.1.3.2.7).

1990 collector performance is projected to be the same as that in 1985, assuming the full Section 8.2 improvements are fully realized by 1985.

8.2.7.3 Energy Capacity Charges

On a cost of energy capacity basis (assuming $1980), our cost/performance improvements projections are significant: (These costs exclude contingency and owners engineering charges).

	1980	1990
Steam	$5860/$KW_{th}$ ($196/MBTU-YR)	$2490/$KW_{th}$ ($83/MBTU-YR)
Preheat-Only	$4150/$KW_{th}$ ($139/MBTU-YR)	$1910/$KW_{th}$ ($64/MBTU-YR)

To a first order these costs will yield levelized energy costs on the order of $5.6/$10^9$J to $7.8/$10^9$J ($5.9 to $8.2/MBTU) after tax assuming 28% tax credits (before passage of the WPT) and 2.9% annual operations and maintenance. A comparable fossil fired boiler energy cost is on the order of $8.3/$10^9$ J ($8.8/MBTU) assuming lease crude oil fuel, today's efficiencies, and prices per Section 8.1.

8.2.8 DISCUSSION AND SUMMARY

This task has analyzed the potential for cost and performance improvements in line focus collector systems. Our review has included the major subsystems and their components and has focused upon both the technical and economic improvements.

One area of concern is the collector module itself. There appear to be no significant technical barriers to increasing annual performance by up to 50% and decreasing F.O.B. factory costs by 50%. A market barrier, however, does exist. A certain level of predictable and profitable sales volume for collector manufacturers is a necessary condition for the prudent investments in plant and process which are implied by an 85% learning rate and the assumed introduction of improved performance features. However, collector costs today are not economically attractive and the market requires external support as explained in the next section, if improvements are to occur. Beyond the collector, the other subsystem costs must also be reduced. This will require further innovation by designers and contractors. A strong market outlook can stimulate this response, however, its occurrence is uncertain.

8.2.8.1 DOE Support To Facilitate Learning

From our learning curve analysis and current costs, solar is clearly uneconomic today without grants or special incentives such as Tertiary Front End Revenue (see section 8.5). Absolute minimum industry production volumes on the order of 27,000 M^2/year (291,000 ft^2/year) are required if the learning (in Figures 8.5 and 8.6) is to occur. To a first order, 40 to 60 percent of this cost would need to be supplied by DOE to make up for Tertiary Incentives which expire in 1981. At current prices, incentive would amount to $3 million in 1982. (The cumulative 1982-1985 incentive would be about $11 million). To meet DOE goals (see Figure 8.6), this would need to be nearly tripled (i.e. to $30 million). A more precise figure would require a detailed breakeven analysis. Absent such support, it is unclear if costs would ever come down, since suppliers could not justify adding new plant and equipment. Also, improved performance features might be delayed.

8.2.8.2 <u>Mass Production Comparison</u>

A second test of the reasonableness of these assumptions is how well the implied annual production levels compare to "mass production". Our 1980-1982 trend's expected production volumes of about 740 units (9,300 M^2) (100,000 ft^2) per vendor per year are very low compared with "mass production" volumes such as the 25,000 unit (1,225,000 M^2) (13,200,000 ft^2) per year minimum mass production plant size suggested by a SERI study for heliostat mirrors (8-59). Even the "DOE goals" trend is only 2900 units (36,000 M^2) (390,000 ft^2) per year. As a result, learning rates of 85% may not be achieved as we have projected. Lower learning rates will imply larger commercialization incentives over longer periods.

Beyond the collector subsystem, other cost savings will also depend in part upon the sales volume of collectors. In the controls area, mature designs will be available only when collector unit volumes increase. Changes to pipe and insulation practices may be forthcoming without an increased demand, but increased installations will accelerate the process. Design costs will follow the total of other costs, and hence collector volume.

8.2.8.3 <u>Investment By Manufacturers</u>

One approach to corporate financial planning is to employ financial ratios to estimate needs for capital and working capital. As sales and production increase, the capital base needs to expand (8-60). On an average basis:

$$\frac{\text{Profit}}{\text{Investment}} = \frac{\text{Sales}}{\text{Investment}} \times \frac{\text{Profit}}{\text{Sales}}$$

If a weighted average return of 20% is desired and if one assumes a 5% to 10% after-tax profit on hardware sales, then sales to investment must be:

$$\frac{\text{Profit}}{\text{Sales}} = 0.05 \text{ to } 0.10 \qquad \frac{\text{Profit}}{\text{Investment}} = 0.20$$

$$\frac{\text{Sales}}{\text{Investment}} = \frac{0.2}{0.05 \text{ to } 0.10} = 4 \text{ to } 2$$

or added investment=1/2 to 1/4 of added sales.

If one applies such a ratio test to new investments to meet DOE goals for sales then, each manufacturer would need to add about 2 to 4 times current sales (4 X to get on the DOE Trend) or up to 4 (growth in sales) x 1/2 (investment/sales) x 9,300 M^2 (100,000 ft^2) base sales level) x \$215/M^2 (\$20/ft^2) 1980 sales price) = \$3.9 million to his investment base.

Such an addition would only be made, if corresponding sales were likely. The \$3.9 million is probably affordable by today's manufacturers. However, if "mass production" volumes are required, then an investment on the order of \$80 million as suggested by the SERI report would be necessary to build and equip a 25,000 unit per year equivalent manufacturing plant in the southwest. (See reference 8-59 for a detailed explanation of the basis of the SERI reported estimate). It seems unlikely that current volumes (740 units per year per the 1980-1982 trend) would justify adoption of the cost saving mass production techniques implicit in the \$80 million dollar (SERI report) plant. This leaves open the question of the degree of unit cost improvement that would really be accomplished, if actual average producer new plant and process investments were between the \$3.9 million of this section and the \$80 million for a 25,000 unit plant.

8.3 Applicability of Parabolic Trough Solar Collectors in Thermal Enhanced Oil Recovery

8.3.1 Introduction

The objective of this study was to make preliminary investigations of the effects of certain basic process variables on the U.S. applicability of parabolic trough solar collectors to enhanced oil recovery. Such screens made at appropriate stages during the development and application of a new technology aid in evaluation of achievable targets and in prevention of expensive excursions into unprofitable areas. Items of particular interest for this study were: (1) existence near heavy oil fields of land technically suitable for installation of parabolic trough solar collectors and (2) the effects of enhanced oil recovery steam requirements on solar energy utilization. The first plays a key role in the availability of solar energy, and the second provides a measure of the outer boundaries of the target for STEOR applications. Each represents a limitation on the applicability of parabolic trough solar collectors. However, it should be noted that neither defines the probability of such usage occurring.

8.3.2 Factors Affecting the STEOR Applicability of Parabolic Trough Solar Collectors

A general discussion of factors Table 8.8 affecting the STEOR applicability of parabolic trough solar collectors will be given to provide a background for the studies undertaken and to indicate more precisely the meaning of the results of these studies with regard to potential for solar energy use in this field. Factors of major importance are: (1) solar energy availability, (2) limiting values for solar energy utilization, (3) solar energy economics, and (4) timing of development and application of solar energy technology.

8.3.2.1 Solar Energy Availability

Solar energy availability is determined by the average intensity of solar radiation falling on the location of interest (solar insolation), total available area suitable for installation of solar collectors, and the status of solar collector technology.

TABLE 8.8

FACTORS AFFECTING THE STEOR APPLICABILITY OF PARABOLIC TROUGH SOLAR COLLECTORS

- Solar Energy Availability
    - Solar Insolation
    - Area for Solar Energy Collection
        - Surface Suitability *
            - Topography
            - Surface Use
            - Surface Location (Steam Transmission Limits)
        - Surface Availability
            - Total Surface Leasing or Purchase
            - Government Regulations Concerning Land Surface Use
    - Status of Solar Energy Technology
        - Collector Efficiency
        - Steam Pressure Limitations **
- EOR Limitations on Solar Energy Utilization
    - Projections of EOR Steam Requirements *
    - Solar Fraction of Total Energy **
- Solar Energy Economics
- Timing of Development and Application of Solar Energy Technology

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* Factors receiving major attention in the present study.
** Factors receiving secondary attention in the present study.

Solar Insolation

Values of solar insolation are not presently available for the locations of all heavy oil fields included in this study. Accordingly, a constant value of 947 kWh/M^2 ($0.3\ MBTU/ft^2$) solar collector)(year) was used to represent delivered energy (including the efficiency of the solar collector system) for all locations. This is a value generally representative of the Bakersfield, California, area.

Surface Suitability

Surface suitability is determined by topography, surface use, and location with respect to steam injection needs.

Topography. A relatively flat land surface is desirable for distribution of an array of parabolic trough solar collectors. A slope downward to the south can give increased efficiencies, but a slope downward to the north is undesirable. Slopes to the east or west will give undesirable shading for a part of each day.

It is technically feasible to utilize scattered arrays of solar collectors on selected portions of an undulating or rough land surface. The net effect is to reduce their concentration, thus requiring greater total land surface for a given steam generation capacity. This accentuates one of the disadvantages of the solar systems, that of requirement for very large surface areas. In addition, unit costs for steam generated are increased.

Land Surface Use. Land surface use also has a pronounced effect upon the applicability of parabolic trough solar collectors. Within the field, room must be reserved for normal oil field operations. Both inside and outside the field, the solar collectors must compete with other land uses such as industry, housing, and farming.

Surface Location. The location of land surface considered for solar collectors is important due to its effect on length of steam transmission lines. The maximum distance between fossil fuel generators and injection wells is about 1.6 Km. (1 mi.) for present steam operations, However, some operators recommend considerably shorter lines. The solar systems are subject to the disadvantage that steam lines cool overnight. Each day is started with a cold line containing condensed steam.

The primary use of steam transmission limitations in this study lay in the consideration of only those land surfaces within 1.6 Km. (1 mi.) of a field under consideration. Some attention was also given to the fact that certain field areas might not be accessible by 1.6 Km. (1 mi.) steam lines.

Surface Availability

Land surface technically suitable for installation of solar panels may not necessarily be available for that purpose. Conventional oil and gas leases do not convey the right to utilize 100 percent of the land surface.

Consequently, for land either inside or outside the field, some kind of total surface leasing or land purchase will be required. Strong resistance to extensive land saturation by solar collectors is to be expected from other land use groups such as ranchers and farmers. A rapid climb of lease and purchase costs can also be expected.

State or federal regulations on land use may also affect extensive use of solar collectors. Although solar energy is considered to be pollution-free with regard to air and water, the question of "land pollution" has not been addressed. The distribution of solar collectors very severely restricts other uses of the land.

Status of Solar Energy Technology

The efficiency of collection or conversion of incident solar energy is a third major element in the availability of solar energy. As an emerging and rapidly growing technology, the testing of parabolic trough solar collectors has not been extensive. Although considered potentially to be very reliable equipment involving little down time, this has not been proved by long-term experience.

Since it is anticipated that considerable improvements will be made in solar hardware, equipment efficiency was not made a variable in the present study. As indicated previously, a constant value of 947 kWh/M^2(0.3MBTU/ft^2)/year was used as the delivered energy for all locations considered. No allowance was made for equipment down time.

Another equipment-centered factor in solar energy availability is the ability of the equipment to deliver steam at needed temperatures and pressures. Present parabolic trough collectors encounter increasing difficulties with rising steam pressure. As a guide for future equipment design, this study included a survey of wellhead pressures for present steam injection projects.

8.3.2.2 EOR Limitations on Solar Energy Utilization

Regardless of solar energy availability, its STEOR utilization is limited at any location by levels of steam injection and by the duration of steam injection activities. The duration of steam injection is of importance because of its effects on the overall economics of a solar thermal enhanced recovery project. Accordingly, key parts of the present investigation were dedicated to determining for each field best possible values for present steam injection capacity, anticipated maximum steam injection capacity, and duration of steam injection activities.

Although total EOR steam injection capacity might be taken as the maximum for solar steam utilization, lower values are probably more realistic. A 100 percent invasion of the thermal enhanced recovery steam market by solar energy would imply the following: (1) replacement of all presently installed fossil fuel steam generators and (2) development of stand-alone solar systems involving solutions to problems associated with diurnal energy production. With regard to steam utilization, increases in steam generation capacity provide a much more likely target for solar steam than does replacement of present fossil fuel units. A 100 percent solar system requires either diurnal steam injection at very high rates or the development of an efficient and cost-effective high-temperature storage system. In either case, land requirements for solar collectors are quite high. Accordingly, effects of limitations on solar fraction of EOR steam requirements were included in the present study.

8.3.2.3 Solar Energy Economics

Comparative economics for use of solar-generated steam and for that from competing energy sources will play a major role in future choices of energy systems for thermal enhanced oil recovery. Although not included in the present investigation, economic screens will be an important factor in future decisions (see 8.5).

8.3.2.4 Timing of Development of Solar Energy Technology

ıne timing of development and application of solar technology is also an important factor in controlling solar entry into enhanced oil recovery. With the passage of time, the number of fossil fuel generators, with associated pollution control equipment, increases. It will be considerably more difficult for solar generation facilities to displace installed fossil fuel steam generators than to compete successfully with them as original equipment in new applications.

8.3.3 Methods Used in Screening Study

The approach used in this screening study was to make detailed investigations for each of the heavy oil reservoirs used in the 1976 projections of enhanced oil recovery in the United States by the National Petroleum Council. A description of this data base and of the collection and analyses of data is given in the following paragraphs (8-61).

8.3.3.1 Data Base of California Heavy Oil Fields

A listing of the heavy oil reservoirs used in the 1976 study of enhanced oil recovery by the National Petroleum Council was obtained from individuals who had participated in that project. In addition, copies of the data sheets for each of the fields were also provided. These reservoirs are listed in table 8.9 along with the NPC values for oil originally in place and for projections of net enhanced oil recovery after fuel deduction (NPC base case estimate). A third set of figures represents the values for total steam

TABLE 8.9

CALIFORNIA HEAVY OIL RESERVOIRS USED IN SCREENING STUDY

Field - Reservoir	OOIP[1] (10^6 bbls)	Est. Net[1] EOR (10^6 bbls)	Steam Inj.[2] 1979 (bbls)[3]
Brea Olinda - Olinda Area	272	49	738,849
Buena Vista - Upper Hills	1,747	121	56,408
Cat Canyon - Sisquoc Area	284	38	4,134,029
Coalinga - Temblor	2,762	293	5,674,569
Edison - Upper Main	217	15	443,296
Fruitvale - Chanac Kernco Main	439	65	58,409
Huntington Beach - North Area Tar Bolsa	1,646	300	211,797
Inglewood - Vickers	919	69	0
Kern Front - Main	652	82	3,995,613
Kern River - Kern River	4,000	585	144,459,271
Lost Hills - Main	428	41	2,925,869
McKittrick - Upper Main	710	79	4,017,470
Midway Sunset - Potter	5,499	780	50,601,405
Mount Poso - Vedder	747	52	25,284,857
Orcutt - Monterey Point Sal	716	84	0
Richfield - East and West Area	746	83	0
San Ardo - Lombardi	975	94	40,401,638
South Belridge - Tulare	1,078	137	43,003,157
Torrance - Puente	699	73	0
Wilmington - Ranger	1,316	64	193,542
Wilmington - Upper Terminal	2,397	170	
Totals	28,249	3,274	326,200,179
Total California			355,997,924

NOTES: (1) Reference (8-61)
(2) Reference (8-62)
(3) 1 barrel = 0.1590 M^3.

injected in each of these fields for the year 1979. These are preliminary figures made available by the California Division of Oil and Gas. (8-62) The data base reservoirs accounted for 91.6 percent of all steam injected into California heavy oil reservoirs during 1979. Locations of the fields are shown in Figure 8.7.

8.3.3.2 Data Acquisition

Data acquisition activities were directed primarily toward developing information necessary to determine the existence of land in and near each field suitable for solar collector installation and to project future heavy oil operations. Although reservoir information was developed beyond that used in the NPC study, no attempt was made to include within the present project a reservoir study of each field under consideration. Rather, the reservoir information was used to provide a better understanding of projections made by the individual companies. Sources of information included detailed field and topographic maps, interviews with major thermal operators in each field, interviews with other experts, and on-site field inspections.

Maps

Topographic maps prepared by the United States Geological Survey were obtained for the areas in and around the heavy oil fields of interest. These were of the 7.5-minute series, with a scale of 2-2/3 inch = 1 mile. A listing is given in Table 8.14.

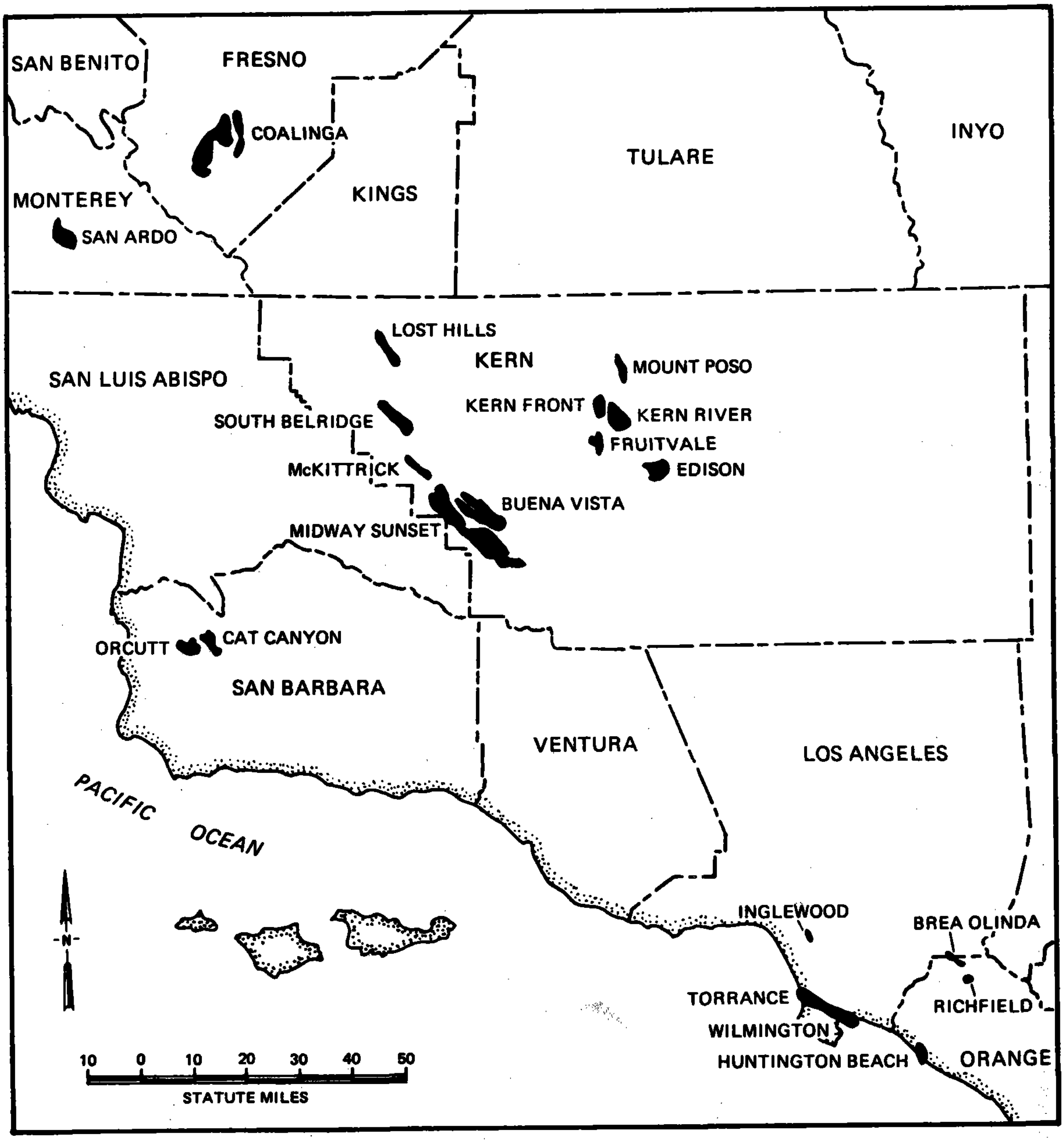
Detailed field maps and regional wildcat maps (listed in Table 8.14) were obtained from the Division of Oil and Gas of the State of California. The field maps show all wells by type and all leaseholders. However, they show legal field limits rather than the needed proved limits. The regional wildcat maps provided the latter. In only one case was a deviation made from the field limits given by the regional wildcat maps. A small extension was made at the northern end of the Kern Front field.

Interviews with Major Thermal Recovery Operators in Each Field

To obtain latest information on present and projected future steam operations, experts were consulted from the major steam operators in each of the fields under consideration. It should be emphasized that the screening factor for selection of these companies was whether or not their operations comprised a significant fraction of the operations in any one field, not their ranking in the overall picture. Cooperation was excellent. All companies approached, with one exception, provided input information. Companies providing information on their operations are listed in Table 8.10.

Information sought for each field included the following:

(1) Present and projected well spacing.
(2) Present and projected steam injection capacity. (An "in service" factor of 75 percent of the actual installed capacity was used.)



LOCATION OF CALIFORNIA HEAVY OIL FIELDS USED IN STEOR SCREENING STUDY.

FIGURE 8.7

TABLE 8.10

COMPANIES PROVIDING INPUT INFORMATION TO STEOR SCREENING STUDY

ARCO Oil and Gas Company

Chevron U.S.A., Inc.

Conoco Inc.

Exxon Company, U.S.A.

Getty Oil Company

Gulf Oil Exploration and Production

Mobil Oil Corporation

Shell Oil Co.

Texaco Inc.

Union Oil of California

(3) Steam surface pressure.
(4) Fuel used.
(5) Desired "protected" space requirements around each well for normal oil field operations.
(6) Anticipated life of steam injection operations.

Interviews with Other Experts

Experts outside the major operating companies also provided useful information for this study. Engineers and officers of the California Division of Oil and Gas gave freely of their time. County agriculture commissioners from each of the counties of interest provided information on agricultural land use and land values. Other experts included a real estate agent (projected industrial and residential land use) and a geological consultant (consultant to city of Bakersfield on "protected" land needs around each well for normal oil field operations).

On-Site Field Inspections

Inspection trips were made to those fields which were expected to provide the major potential for application of parabolic trough solar collectors. The inspection team consisted of one individual with experience in thermal recovery operations (C. W. Arnold of EPR*)and one with solar collector experience (Don Duffy of Acurex). Inspections were made by driving on lease and public roads through the fields. Fields visited included: South Belridge, Buena Vista, Cat Canyon, Coalinga, Edison, Fruitvale, Kern Front, Kern River, Lost Hills, Midway-Sunset, Mount Poso, Orcutt, and San Ardo. The visits to Kern River and Cat Canyon were limited to driving along one edge of each field.

The solar expert made judgments on the effects of topography on the fraction of specific areas, F_t, that might be amenable to distribution of solar collectors. Minor levels of grading and earth moving were assumed, but massive surface restructure was not considered. Close study of these areas with U.S.G.S. topographic maps aided in the making of judgments from topographic maps alone for areas not visited. Discussions with individuals well acquainted with the latter areas provided additional information.

8.3.3.3 Data Analysis

Certain fields were eliminated from consideration at a relatively early stage in the study, and detailed analyses were made for only those fields remaining. Orcutt and Buena Vista were eliminated because of lack of indicated interest in steam injection operations. Fields in the Los Angeles area were eliminated because of intense industrial and residential land use or because of ocean coverage. Fruitvale was eliminated because it is expected to be covered by the City of Bakersfield within five years.

* Exxon Production Research Company

Fraction of Land Surface Reserved for Oil Production Operations

For estimation of the fraction of land available for solar panels within an oil field, F_w, a five-spot well pattern was assumed (see Appendix I-1). From discussions with companies involved in steam injection operations and from special consideration of a recent ordinance passed by the City of Bakersfield, California, a square 45.7m (150 ft.) on each side was reserved around each well for normal oil production operations. The wells were connected in rows by 9.1m (30 ft.) service roads.

Decreasing well spacing (acres/well) obviously reduces the fraction of land surface available for solar collectors. Values range from 0.8264 for a spacing of $20 \times 10^3 M^2$ (5 ac.) per well to 0.4876 for a spacing of $5.2 \times 10^3 M^2$ (1.28 ac.) per well. As the decreasing spacing approaches $4 \times 10^3 M^2$ (1 ac.) per well, steam costs rise precipitously. Consequently, no allowance was made for solar collector distribution within areas drilled to less than $4 \times 10^3 M^2$ (1 ac.) per well. It should be noted also that surface roughness and close well spacings have similar effects, in each case lowering the concentration of solar collectors. Consequently, surface roughness will increase the minimum well spacing for which solar collectors are considered feasible.

Estimation of Areas Suitable for Installation of Parabolic Trough Solar Collectors

Estimations of areas suitable for installation of parabolic trough solar collectors were made from sketches on topographic maps of field limits and of areas judged to be suitable for the collectors. As mentioned previously, no land was considered at a distance of greater than 0.62 Km. (1 mi.) from a field under consideration. Each area considered for solar collectors was assigned two usage factors, F_t for effects of topography, and F_w for effects of well spacing. The net land available for solar collectors is then equal to the product, $A_{gross}F_tF_w$. A_{gross} was determined by planimetering the indicated areas.

A word is in order with regard to defining those areas outside a field suitable for solar collectors. Land inside a nearby major field was not considered to be available. If the nearby field was a steam injection candidate or was undergoing steam injection, the line defining the solar collector area was drawn halfway between the two fields. If the nearby field was not a steam injection candidate, land surface up to its proven boundaries was considered available. Very small fields were included within boundaries considered for collectors, but allowance was made for them in the factor, F_t.

The upper bound for solar collector aperture area as provided by this surface suitability screen was given by the following equation:

$$\text{Solar Collector Aperture Area} = (0.35)\ A_{gross}F_tF_w\ M^2 \quad (1)$$

$$=(15{,}246\ A_{gross}F_tF_w\ ft^2)$$

where

0.35 = fraction of net land surface represented by solar panel aperture

A_{gross} = gross land area assumed suitable for solar panels, M^2 (ac.).

The upper bound for solar-generated steam as given by this surface suitability screen was given by the equation:

$$\text{Solar steam cap., bbl/day} = (947)(1/365)(1/102.6)(M^2 \text{ of aperture}) \tag{2}$$

$$= 2.5274 \times 10^{-2} \quad (M^2 \text{ of aperture})$$

$$= 2.348 \times 10^{-3} \ (ft^2 \text{ of aperture})$$

where

947 kWh/(M^2) year (0.3 x MBTU/ft^2 year) = net rate of heat generation from parabolic trough solar collectors

102.6 kWh (350,000 Btu) = approximate energy required to generate one barrel of 80 percent quality steam

EOR Limitations on Solar Energy Utilization

Since maximum future steam generation capacities and the incremental capacities needed to reach these levels play an extremely important role in estimating limiting values for applications of parabolic trough solar collectors, considerable attention was given to developing such estimates. Insofar as possible, these estimates were made from projections of major thermal operators in each field. For very active fields in an advanced stage of development, such as Kern River, South Belridge, San Ardo, and Mount Poso, predictions can be made with considerable confidence from information supplied by the operators. In others, such as Kern Front, Cat Canyon, and Lost Hills, development is at a much earlier stage, and operators are often unwilling to make projections. In such cases, resort was made to other available resources for supporting evidence on future steam generation capacities. For example, comparisons were made of values developed in this study with projections of total steam generation capacity for Kern County made by the California Division of Oil and Gas. Checks were also made against projections by the National Petroleum Council and others. Various attempts were made to use steam injection densities, both within fields and between fields. However, differences in field properties make this approach rather doubtful.

Solar collector aperture areas associated with the steam generation capacities estimated above are calculated by the following equation:

Solar collector aperture area = 39.56 (bbl steam gen. per day) M^2

$$= (425.83)(\text{bbl steam gen. per day})\ ft^2 \quad (3)$$

In all uses of steam generation capacities, the assumption of even injection density throughout a field was used.

Solar Fraction of Total Steam Generation Capacity

As indicated in a previous section, a practical upper limit to solar steam utilization is probably less than the total maximum EOR steam generation capacity. To provide an insight into additional limitations that might occur for a likely field situation, estimates of maximum steam utilization were made for the following assumptions:

(1) Use of hybrid solar-fossil fuel systems with little or no high temperature storage and with the solar and fossil components controlled to avoid peaking above the average steam demand. For this situation, the solar fraction of total steam requirements averages approximately one-third as noted by SERI's STEOR study (8-63). (See 8.4.2 for a discussion on setting an actual upper limit.)

(2) Displacement of active fossil fuel generators by solar generators is precluded.

Maximum solar steam utilization for each field was thus taken to be the smaller of two values: (1) one-third of the total maximum EOR steam generation capacity and (2) the increment needed to expand from today's generating capacity to the anticipated maximum value.

Effects of One-Mile Steam Transmission Limits

In addition to restrictions on land surface considered for solar collectors outside a field, steam transmission limits can also affect capabilities for reaching all areas within a field. To evaluate such effects, the above study utilizing limits on solar steam utilization was adjusted to include one-mile steam transmission limits. Techniques for accomplishing this objective are outlined in Appendix I-1. Each field was divided into three areas: (1) that with no solar steam utilization, (2) that with less than maximum solar steam utilization, and (3) that with maximum solar steam utilization. Limiting values of solar steam utilization capacity were evaluated by summing values for areas of partial and full solar steam utilization for each field. Corresponding values for solar collector aperture area were then calculated using Equation (3).

8.3.4 Discussion of Results of Screening Studies

Results of the preliminary screening studies for STEOR applicability of parabolic trough solar collectors are summarized in Tables 8.11-13. Reservoir names have been dropped from the field/reservoir list. However, where applicable, field areas have been retained.

The upper limits on solar collector applicability as determined by land suitability are shown in Table 8.11. Maps showing areas considered for solar collectors are given, Fig's. 8.8-28, along with photographs of some of the field locations. It should be remembered that only those areas within one mile of the field boundaries were considered. Also, the collector aperture area was assumed to be 0.35 times the net area available for collector installation. The upper limit to steam generation capacity as permitted under this screen is over 2.6 million barrels per day. This capacity is associated with 33.2 x $10^6 M^2$ (357 x $10^6 ft.^2$) of collectors within the field and 71.3 x $10^6 M^2$ (767 x $10^6 ft.^2$) of collectors outside the field. Midway-Sunset, South Belridge, Lost Hills, Coalinga-West, and Edison-Main account for a large fraction of the total.

A word is in order with regard to potential effects of surface use on the suitability of land for installation of solar collectors. As mentioned previously, certain fields were omitted from consideration because of industrial and housing use. No such allowance was made for farm land. However, rough estimates of the division of land surface between farm land and range land were made. These values are also shown in Table 8.11. Approximately 40 percent of the limiting value of 104.4 x $10^6 M^2$ (1,124 x $10^6 ft^2$) of solar collector area represents installations on good farm land. Most of this is outside the fields.

The upper limits to solar collector applicability as determined by EOR steam requirements are shown in Table 8.12. The first data column lists typical wellhead steam pressures for the various fields. These should be used with some caution since the values come from different operators, different parts of fields, and different stages of operations.

Values for present and estimated maximum steam generation capacities are shown in the next two columns. As indicated previously, projected values for maximum steam generation capacities are subject to considerable uncertainty, particularly for those fields in early stages of development. However, there is little question that the total maximum value and the increment needed to reach that value will both be quite large. The estimated total for maximum steam generation capacities for the fields under consideration was over 3.5 million barrels per day. If this were all solar steam, it would represent over 139.4 x $10^6 M^2$ (1,500 x $10^6 ft^2$) of solar collectors. If, on the other hand, the limiting value for solar steam is taken as the smaller of one-third of the maximum steam generating capacity and the increment needed to reach that capacity, a value of 40.6 x $10^6 M^2$ (437 x $10^6 ft^2$) results.

Finally, Table 8.13 presents a more realistic set of limiting values for solar steam that result when a combination of limiting factors are considered. Namely, this set results when surface suitability, EOR steam requirements (solar limited to the smaller of one-third the maximum steam generation capacity and the increment needed to reach that capacity), and a one-mile steam transmission limit are all considered. The limiting totals for these fields under the combination screen are 759,000 barrels per day of steam and 30.2 x $10^6 M^2$ (325 x $10^6 ft^2$) of solar collectors.

TABLE 8.11

APPLICABILITY OF PARABOLIC TROUGH SOLAR COLLECTORS TO CALIFORNIA HEAVY OIL FIELDS

UPPER LIMITS BASED ON LAND SUITABILITY
(within one mile of field boundaries)

	Inside the Field				Outside the Field				Total		
	Farm Land*		Other**		Farm Land*		Other**		Collector Aperture Area		Steam Cap.
Field	A_{gross} (acres)	Coll. Area (10^6 ft^2)	A_{gross} (acres)	Coll. Area (10^6 ft^2)	A_{gross} (acres)	Coll. Area (10^6 ft^2)	A_{gross} (acres)	Coll. Area (10^6 ft^2)	Inside Field (10^6 ft^2)	Outside Field (10^6 ft^2)	(bbl/day)
Midway-Sunset			17,330	151	6,620	91	9,300	119	151	210	848,000
South Belridge			2,900	28	6,620	91	7,080	97	28	188	507,000
Coalinga-West			9,710	84	2,690	37	1,050	12	84	49	312,000
Kern River			2,580	14			1,000	13	14	13	63,000
Lost Hills			3,830	33	6,420	88	5,890	73	33	161	456,000
Kern Front	120	1.1	1,320	10	1,630	23	490	5.2	11	28	92,000
San Ardo	810	7.8	140	1.1	860	12	440	5.0	9.0	17	61,000
Cat Canyon-Sisquoc			750	6.1	2,020	28			6.1	28	80,000
McKittrick-Main			170	1.0			1,480	18	1.0	18	45,000
Edison-Main	2,680	18			3,490	48			18	48	155,000
Mount Poso			170	1.6			600	6.9	1.6	6.9	20,000
	3,610	27	38,900	330	30,350	418	27,330	349	357	767	2,639,000

* Primarily irrigated farm land, value ranging from $1,500 to $7,000 per acre.
** Predominantly range or grazing land.

Note: 1 barrel/day = 0.1590 m^3/day; 10.764 ft^2 = 1M^2; & 4,047 M^2 = 1 acre.

TABLE 8.12

APPLICABILITY OF PARABOLIC TROUGH SOLAR COLLECTORS TO CALIFORNIA HEAVY OIL FIELDS

UPPER LIMITS BASED ON EOR STEAM REQUIREMENTS

	EOR Steam Requirements			Collector Area	
Field	Typ. Well-head Steam Pressure (psi)	Present Steam Gen. Capacity (bbl/day)	Estimated Max. Steam Gen. Cap. (bbl/day)	Assoc. with Max. Steam Gen. Cap. (10^6 ft^2)	Assoc. with Smaller of • 1/3 Max. Steam Gen. Cap. • Future Steam Increment (10^6 ft^2)
Midway-Sunset	400-550	186,000	800,000	341	114
South Belridge	900	169,000	500,000	213	71
Coalinga-West	500-900	64,700	250,000	106	35
Kern River	100-350	856,000	1,070,000	456	91
Lost Hills	600	33,000	160,000	68	23
Kern Front	600	24,000	210,000	89	30
San Ardo	425-600	130,000	230,000	98	33
Cat Canyon-Sisquoc	1200-2000	38,400	160,000	68	23
McKittrick-Main	630	24,500	100,000	43	14
Edison-Main	400-900	2,600	19,000	8	2.6
Mount Poso	600	84,000	84,000	36	0.0
		1,612,200	3,583,000	1,526	437

Notes: 100 psi equals 689 kPa.; 1 barrel/day = 0.1590 M^3/day; 9.29 x $10^5 M^2$ = 10^6 ft^2.

TABLE 8.13

APPLICABILITY OF PARABOLIC TROUGH SOLAR COLLECTORS TO CALIFORNIA HEAVY OIL FIELDS

UPPER LIMITS BASED ON A COMBINATION OF FACTORS*

Field	Coll. Area (10^6 ft^2)	Steam Cap. (bbl/day)
Midway-Sunset	94	221,000
South Belridge	71	167,000
Coalinga-West	31	73,000
Kern River	27	63,000
Lost Hills	23	53,000
Kern Front	23	53,000
San Ardo	22	51,000
Cat Canyon-Sisquoc	18	42,000
McKittrick-Main	13	30,000
Edison-Main	2.6	6,000
Mount Poso	0.0	0
	325	759,000

* Surface Suitability
EOR Steam Requirements
1/3 of Max. Steam or
Future Steam Increment
One-Mile Steam Transmission Limit

Notes: $9.29 \times 10^5 M^2 = 10^6\ ft^2$.

$$0.1590\ \frac{M^3}{day} = \frac{1\ \text{barrel (bbl)}}{day}.$$

8.3.5 Conclusions

The primary concern of this investigation was to determine if the two major screening factors considered, land suitability for collector installation and EOR limitations on solar energy utilization, would limit the applicability of parabolic trough solar collectors to levels insufficient to warrant further development. Although either may have significant effects on specific fields, the totals of the limiting values for the California fields considered are very large. The totals are still large when additional screening factors, such as a lower solar fraction of total EOR energy and a limit on steam transmission distances, are introduced. Thus, these screening factors provide no serious limitations to further development of STEOR applications of parabolic trough solar collectors.

The actual potential for STEOR applications of parabolic trough solar collectors will depend, in addition to the above, upon such critical parameters as land availability for solar collectors and the economics of the solar system.

TABLE 8.14

OFFICIAL MAPS USED IN STEOR SCREENING STUDY

Field	Topographic Maps*	Oil and Gas Field Maps**
Brea Olinda	La Habra, Cal. Yorba Linda, Cal.	106 Brea Olinda
Buena Vista	Fellows, Cal. Taft, Cal. Mouth of Kern, Cal.	402 Buena Vista 403 Buena Vista
Cat Canyon	Sisquoc, Cal. Twitchell Dam, Cal.	310 Cat Canyon, Four Deer
Coalinga	Domengine Ranch, Cal. Curry Mountain, Cal. Joaquin Rocks, Cal. Coalinga, Cal. Alcalde Hills, Cal.	504 Coalinga (South) 505 Coalinga (North)
Edison	Edison, Cal. Lamont, Cal.	434 Mt. View, Edison
Fruitvale	Gosford, Cal. Oildale, Cal.	435 Fruitvale 436 Fruitvale 438 Fruitvale
Huntington Beach	Seal Beach, Cal. Newport Beach, Cal.	133 Huntington Beach 134 Huntington Beach 135 Huntington Beach
Inglewood	Beverly Hills, Cal. Hollywood, Cal. Venice, Cal. Inglewood, Cal.	122 Inglewood
Kern Front	Oildale, Cal. North of Oildale, Cal.	438 Poso Creek, Kern Front
Kern River	Oil Center, Cal. Oildale, Cal. North of Oildale, Cal.	457 Kern River (South) 458 Kern River (North)
Lost Hills	Blackwell's Corner, Cal. Lost Hills, Cal. Lost Hills, NW, Cal. Antelope Plane, Cal.	407 Lost Hills
McKittrick	Reward, Cal. West Elk Hills, Cal.	419 McKittrick

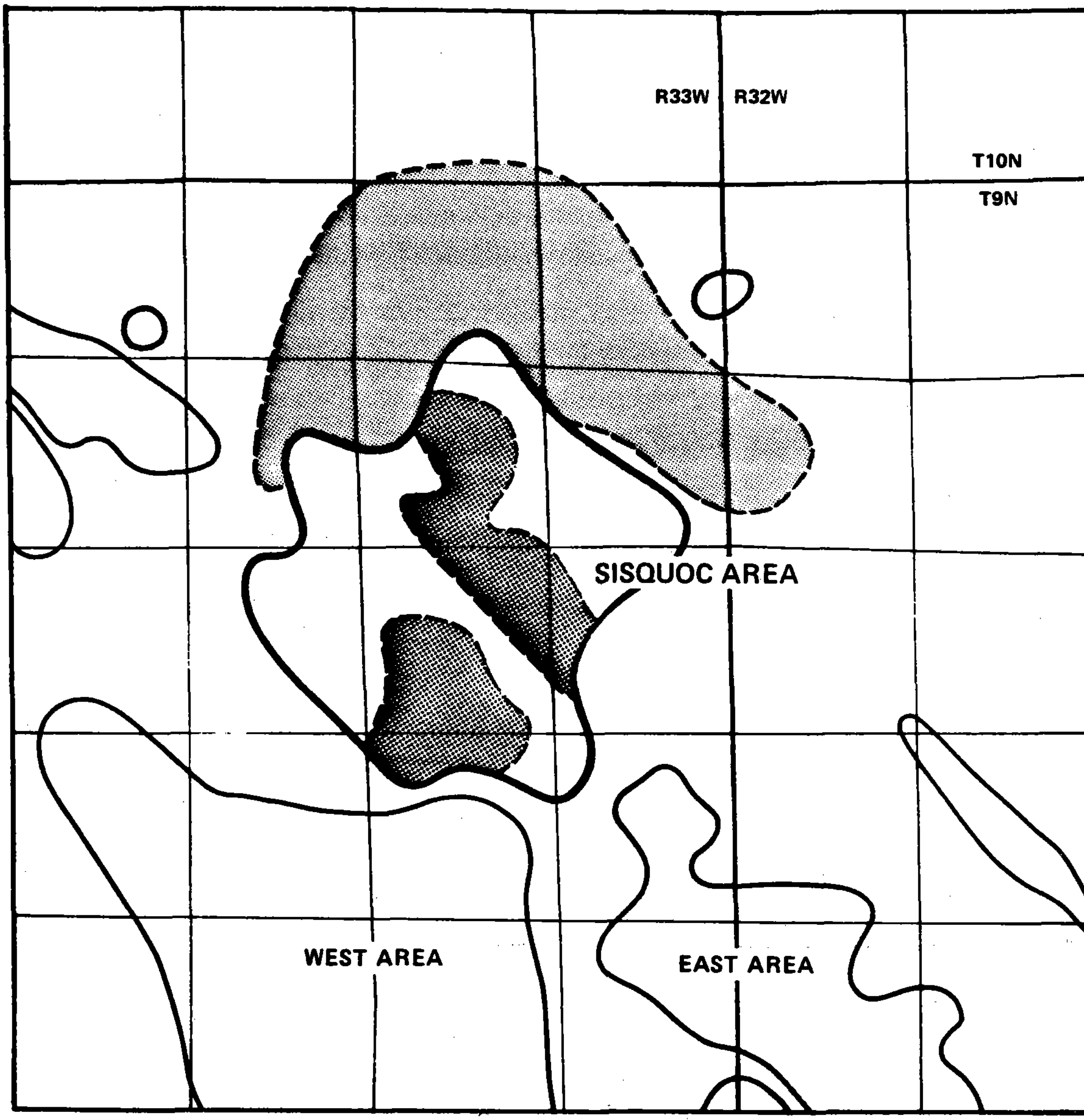
Field	Topographic Maps*	Oil and Gas Field Maps**
Midway-Sunset	West Elk Hills, Cal. Fellows, Cal. Elkhorn Hills, Cal. Taft, Cal. Maricopa, Cal. Pentland, Cal.	401 Midway-Sunset, Southeast 402 Midway-Sunset, East Central 403 Midway-Sunset, North Central 404 Midway-Sunset, North 459 Midway-Sunset, South Central 460 Midway-Sunset, Northeast
Mount Poso	Knob Hill, Cal. Sand Canyon, Cal.	440 Mount Poso 441 Mount Poso
Orcutt	Orcutt, Cal. Sisquoc, Cal.	311 Casmalia, Orcutt, Lompoc
Richfield	Yorba Linda, Cal. Orange, Cal.	108 Richfield
San Ardo	Wunpost, Cal. Hames Valley, Cal.	340 San Ardo
South Belridge	Blackwell's Corner, Cal. Carneros Rocks, Cal. Belridge, Cal. Lost Hills, Cal.	405 South Belridge
Torrance	Redondo Beach, Cal. Torrance, Cal.	126 Torrance
Wilmington	Long Beach, Cal. Torrance, Cal.	128 Wilmington 129 Wilmington 131 Wilmington 132 Wilmington

* U.S. Geological Survey, 7.5-minute series

** California Division of Oil and Gas

The following Regional Wildcat Maps published by the California Division of Oil and Gas were used to aid in establishing field boundaries.

W4-1	Kern (West Side Fields), Santa Barbara, San Luis Obispo Counties
W4-2	Kern County East Side Fields
W3-2	Santa Barbara County
W1-5	Los Angeles and Orange Counties, Northern Los Angeles Basin
W5-1	Portion of Kings, Fresno, Monterey Counties
W3-6	Monterey County



CAT CANYON, SISQUOC AREA – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

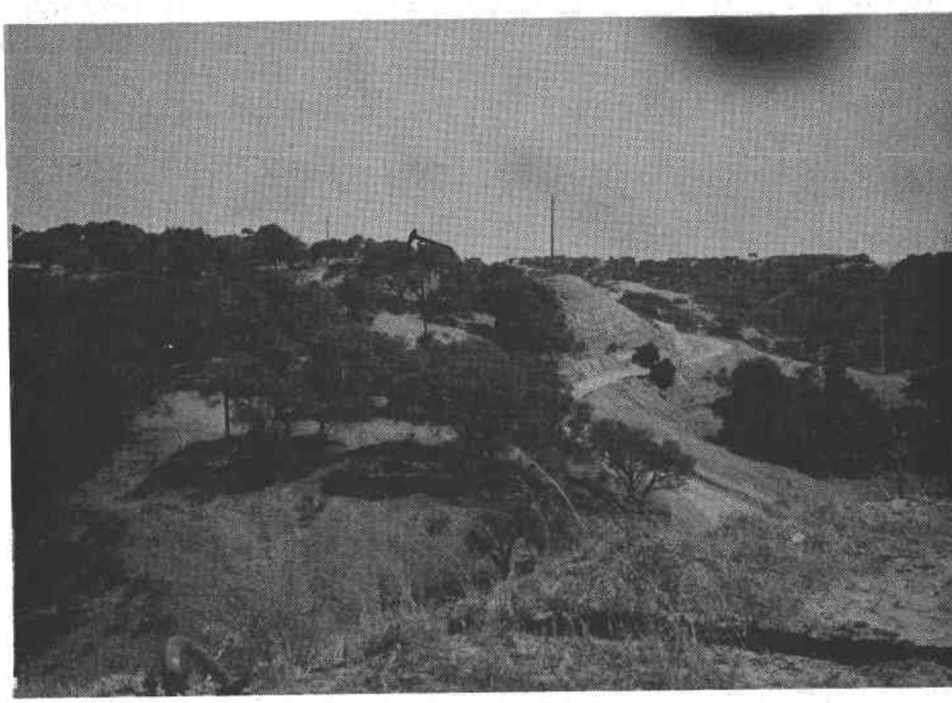
WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 MILES

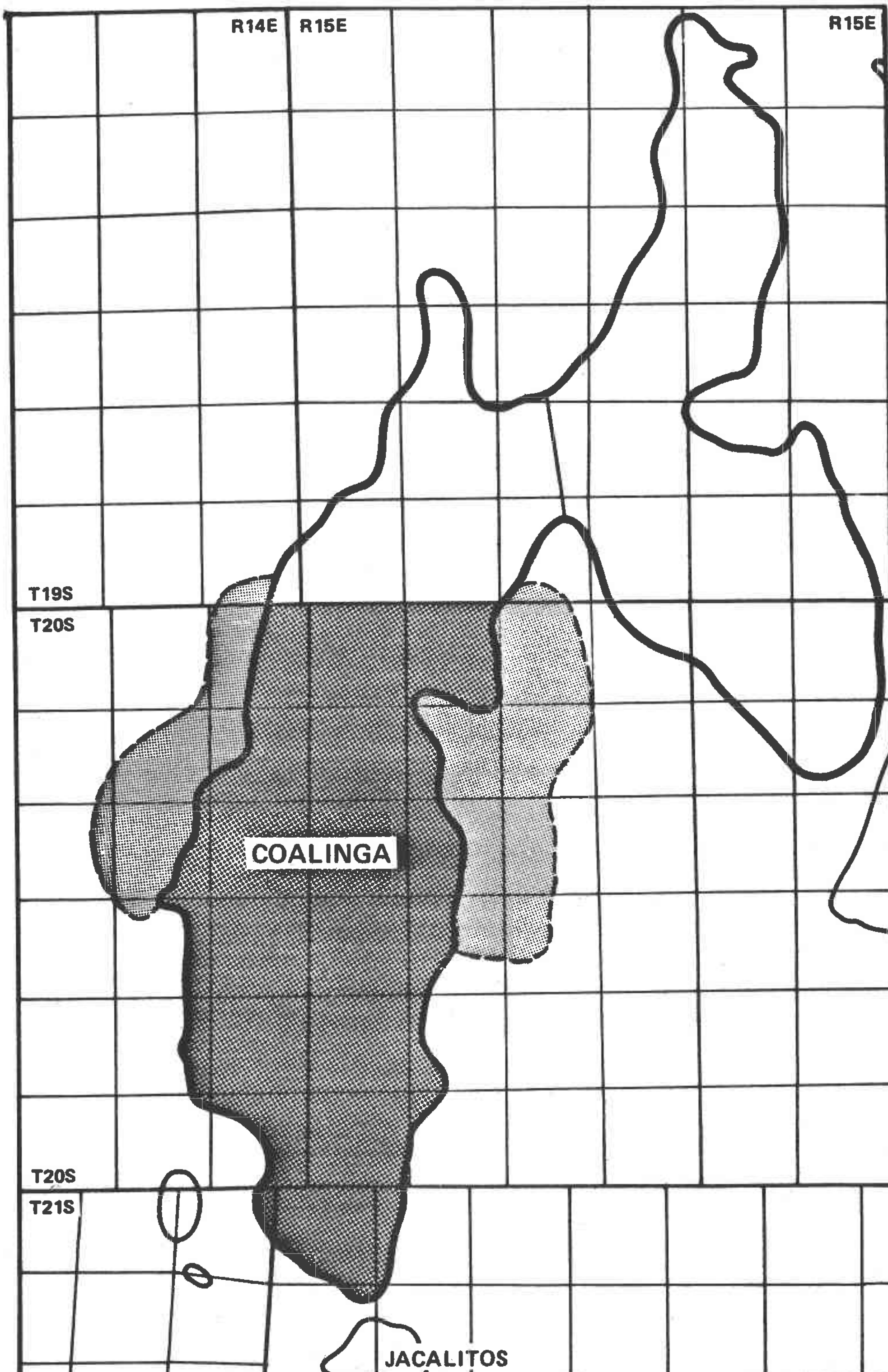
SCALE

FIGURE 8.8



Cat Canyon. Two views south of the Sisquoc Area (Photographs courtesy of the Getty Oil Company).

Figure 8.9



COALINGA – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

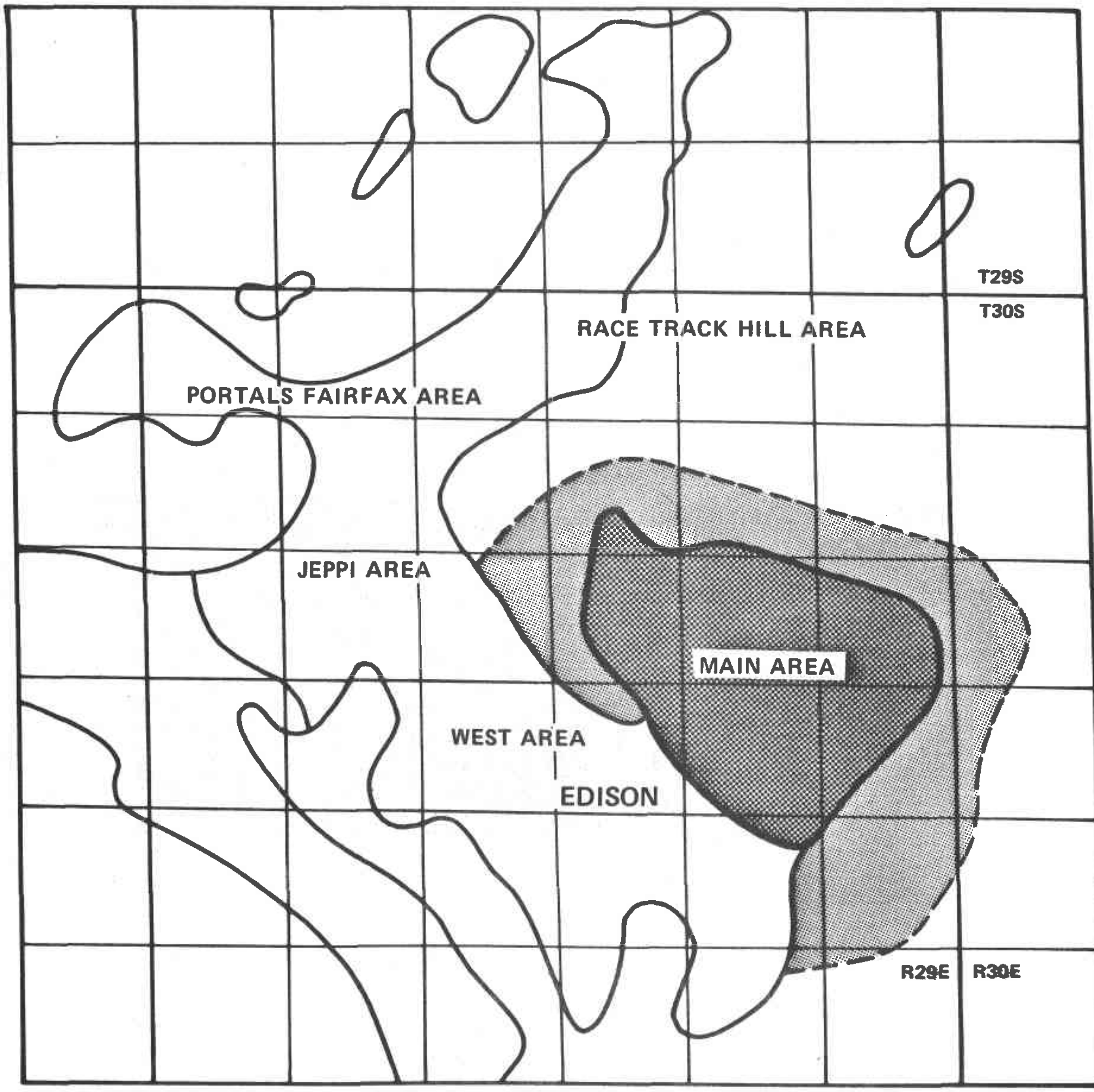
0 1 2 3 MILES

SCALE

FIGURE 8.10

Coalinga. Flat area on the west side of the field.

FIGURE 8.11



EDISON, MAIN AREA – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

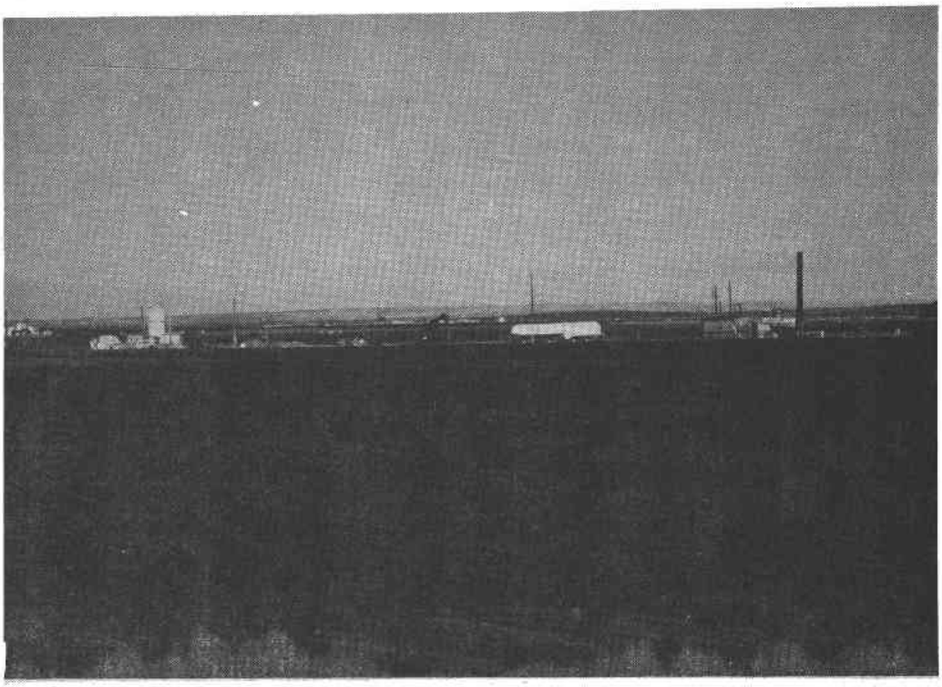
INSIDE THE FIELD

WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 3 MILES
SCALE

FIGURE 8.12

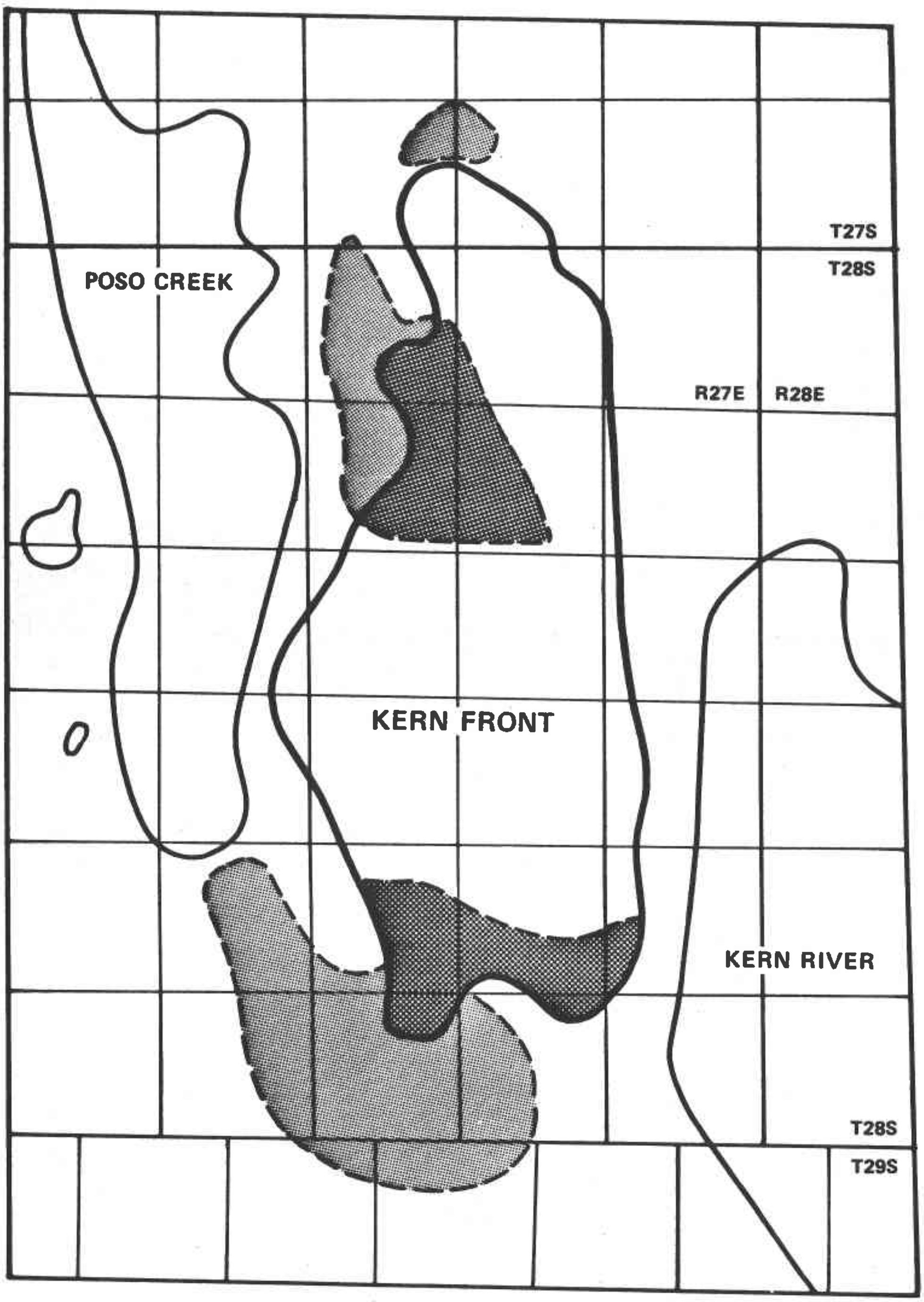


Edison. Typical view.

FIGURE 8.13

Fruitvale. An area covered by business establishments.

FIGURE 8.14



KERN FRONT – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 3 MILES

SCALE

FIGURE 8.15

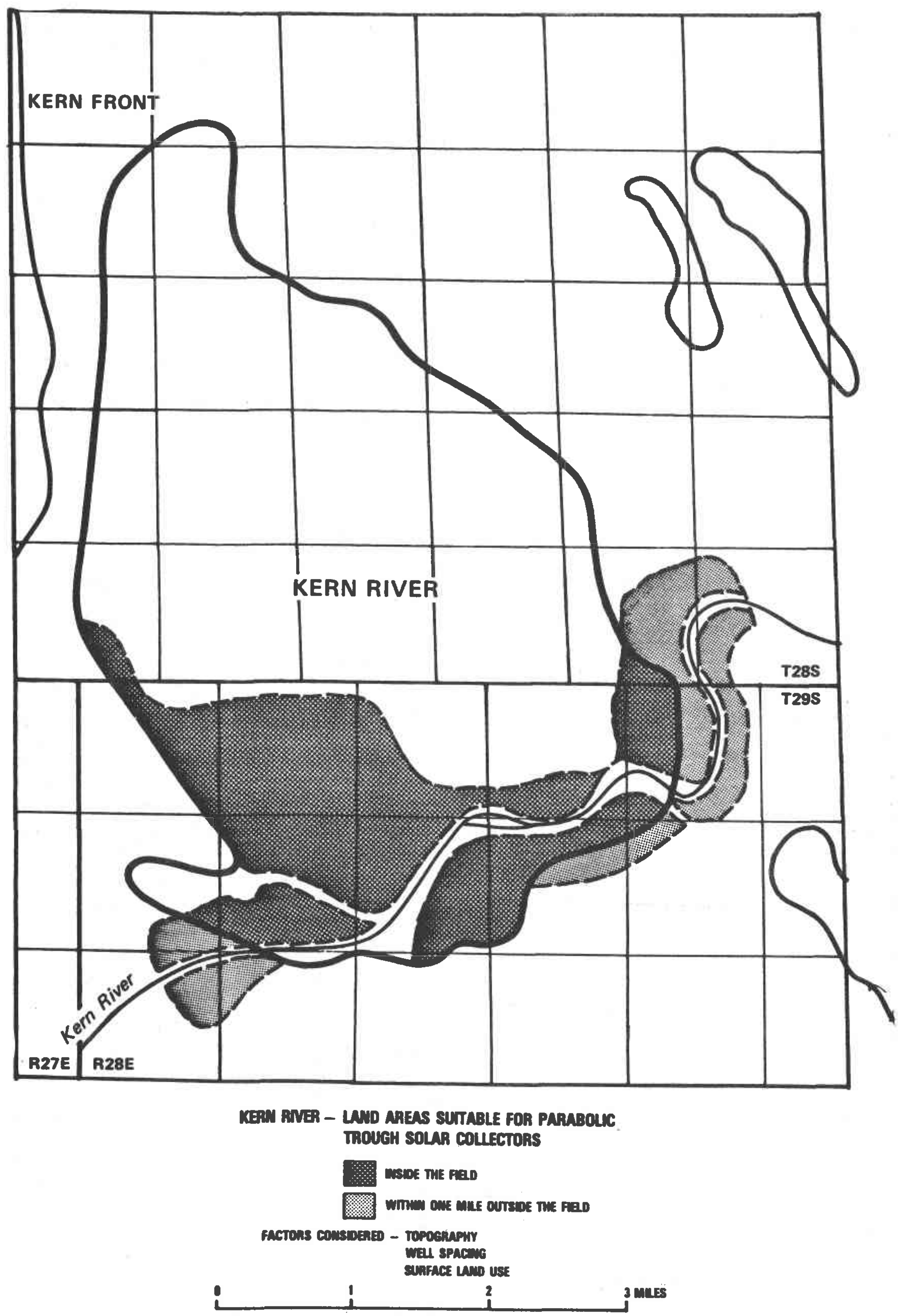
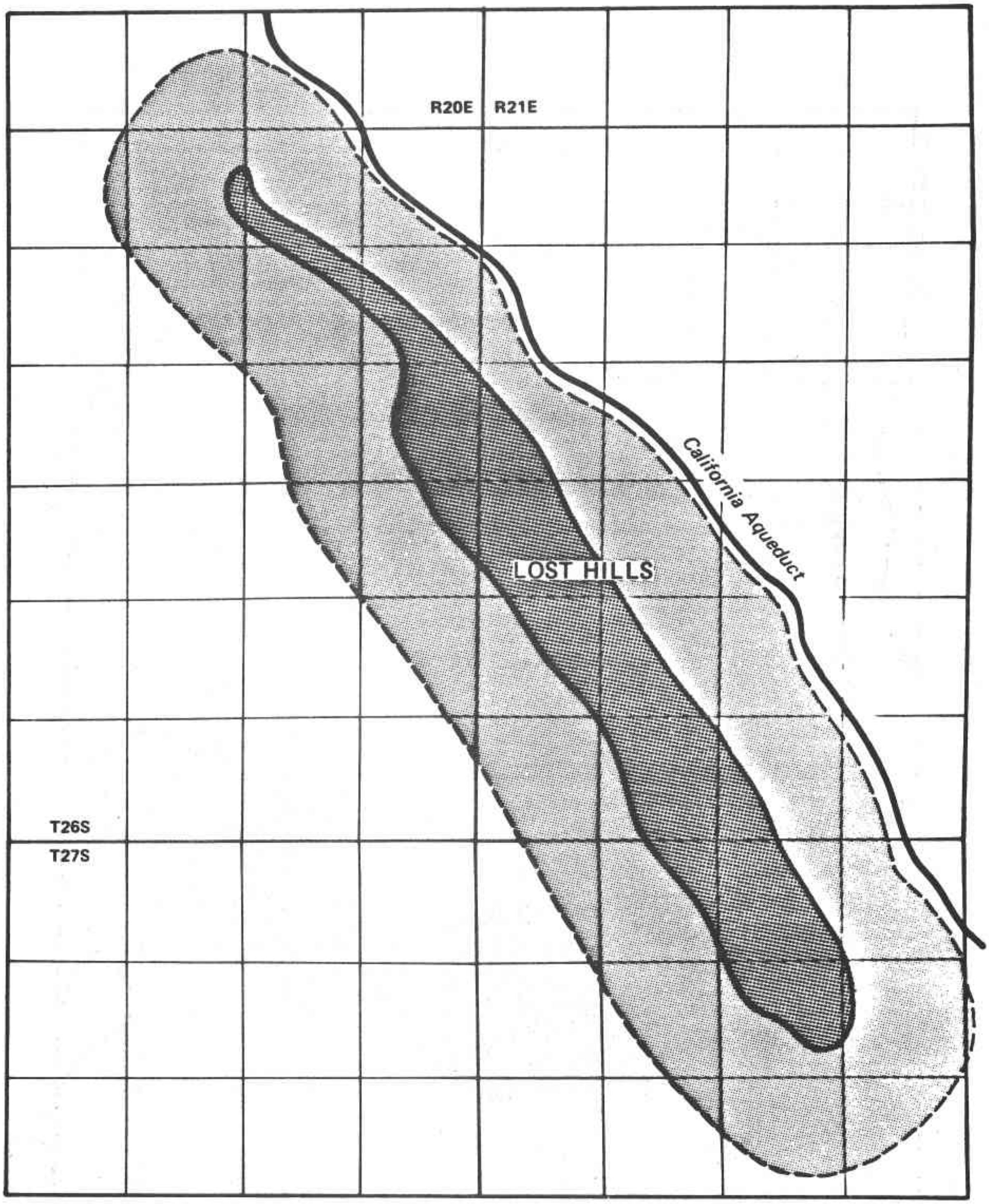

KERN FRONT
KERN RIVER
Kern River
T28S
T29S
R27E
R28E
KERN RIVER – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS
INSIDE THE FIELD
WITHIN ONE MILE OUTSIDE THE FIELD
FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE
0
1
2
3 MILES
SCALE

FIGURE 8.16



LOST HILLS – LAND AREAS SUITABLE FOR PARABOLIC
TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

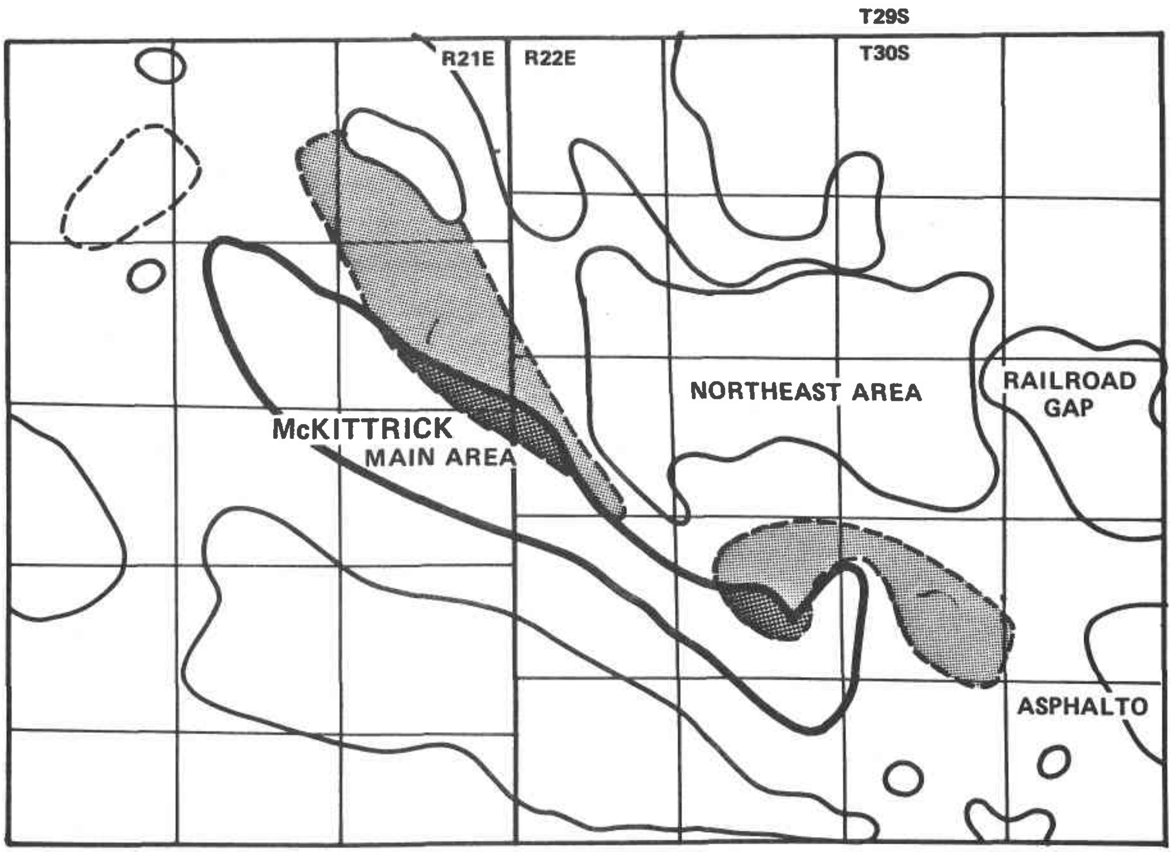
WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 3 MILES

SCALE

FIGURE 8.17



McKITTRICK, MAIN AREA – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

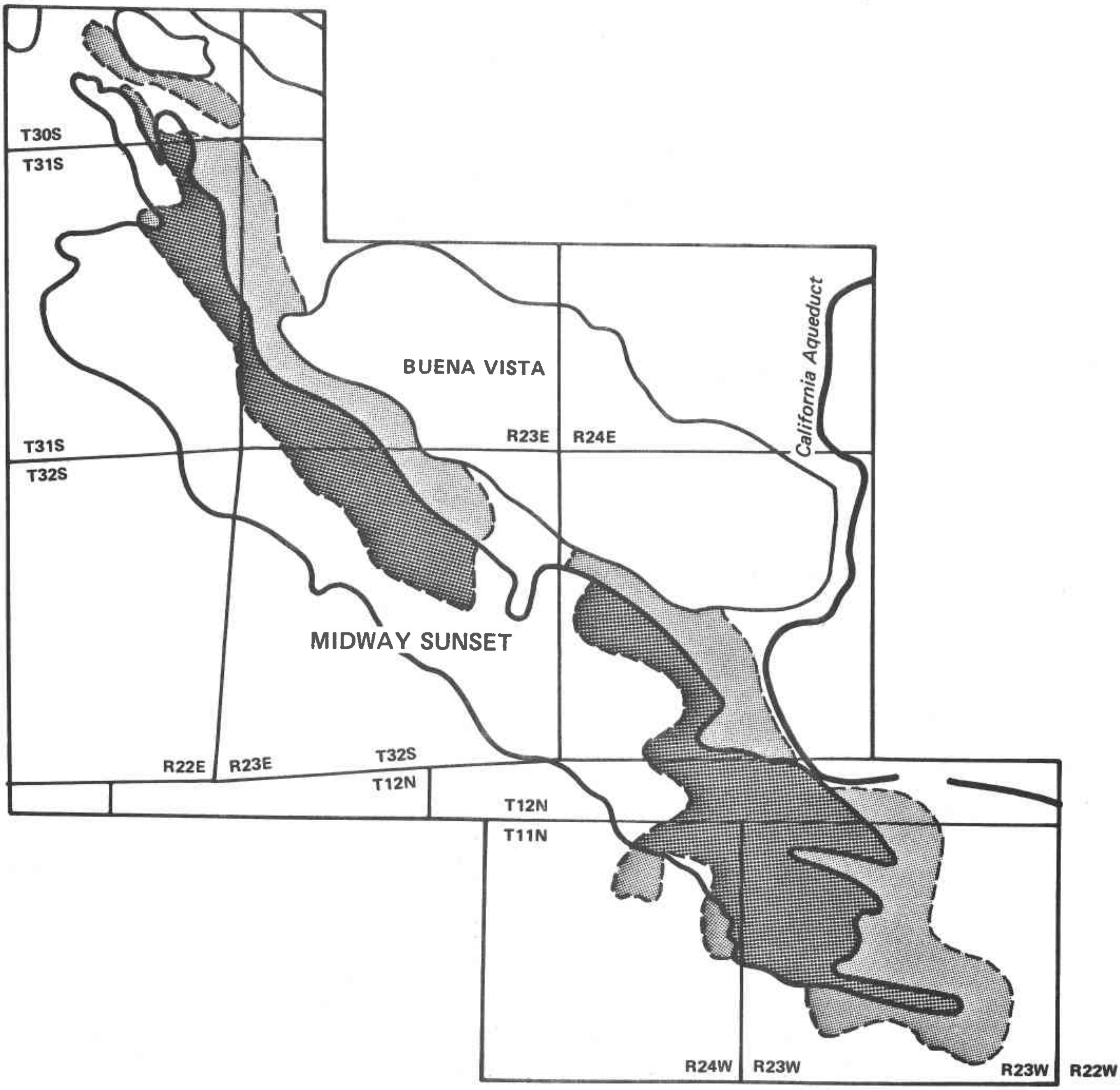
WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 3 MILES

SCALE

FIGURE 8.18



MIDWAY SUNSET – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

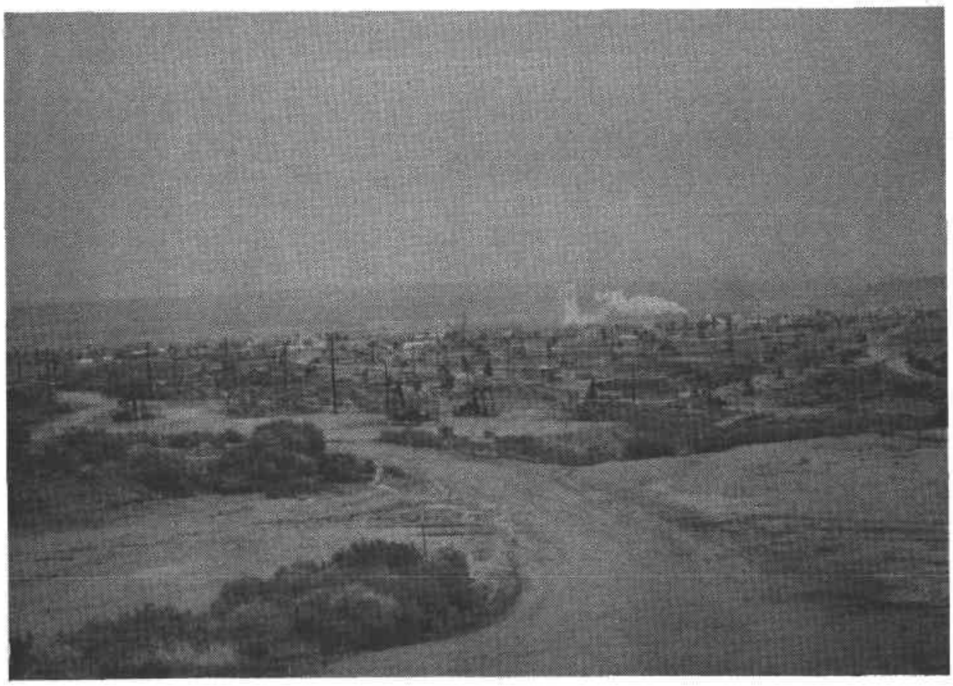
INSIDE THE FIELD

WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

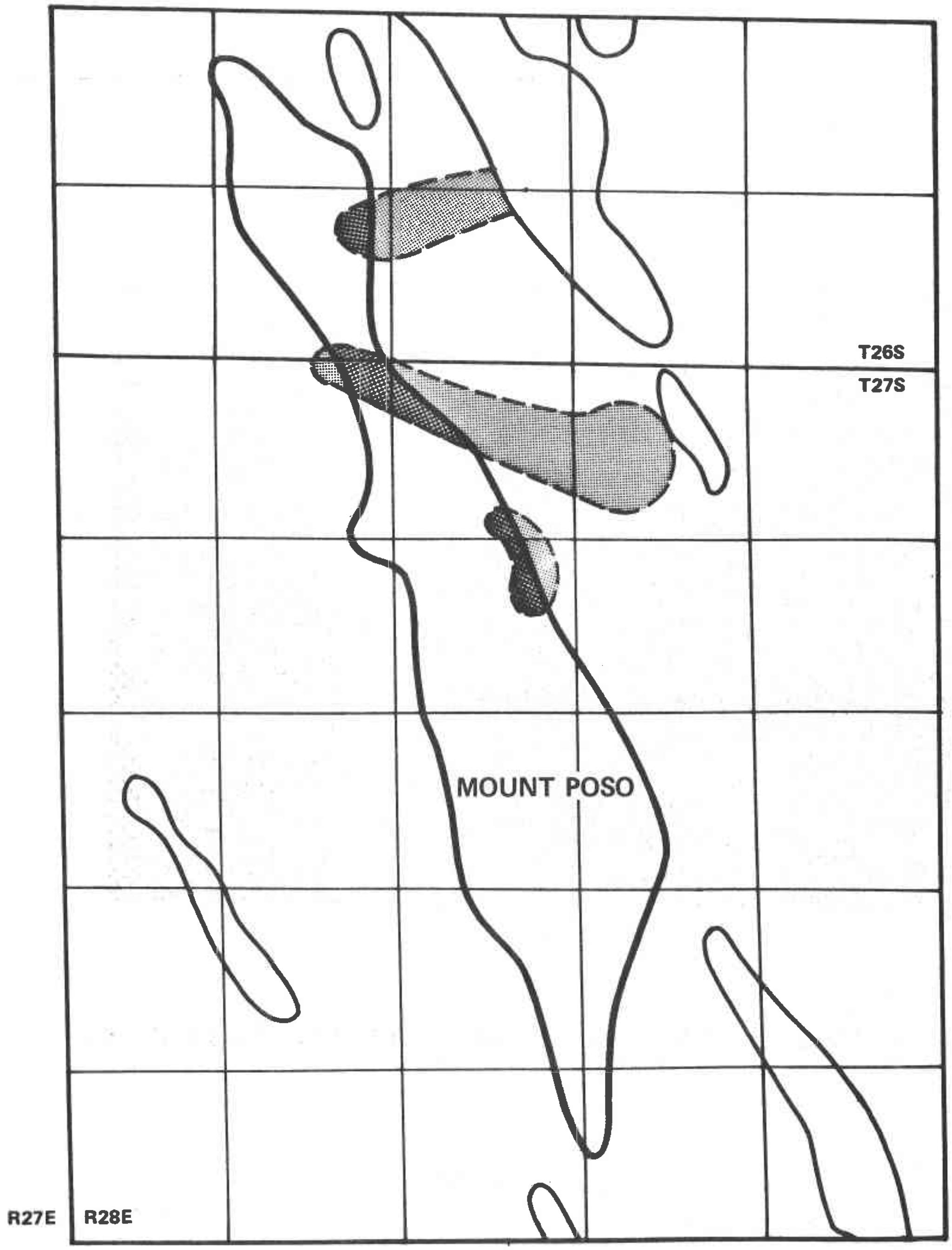
0 1 2 3 MILES
SCALE

FIGURE 8.19



Midway-Sunset. Looking to the east in the heavily developed north central section.

FIGURE 8.20



MOUNT POSO – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

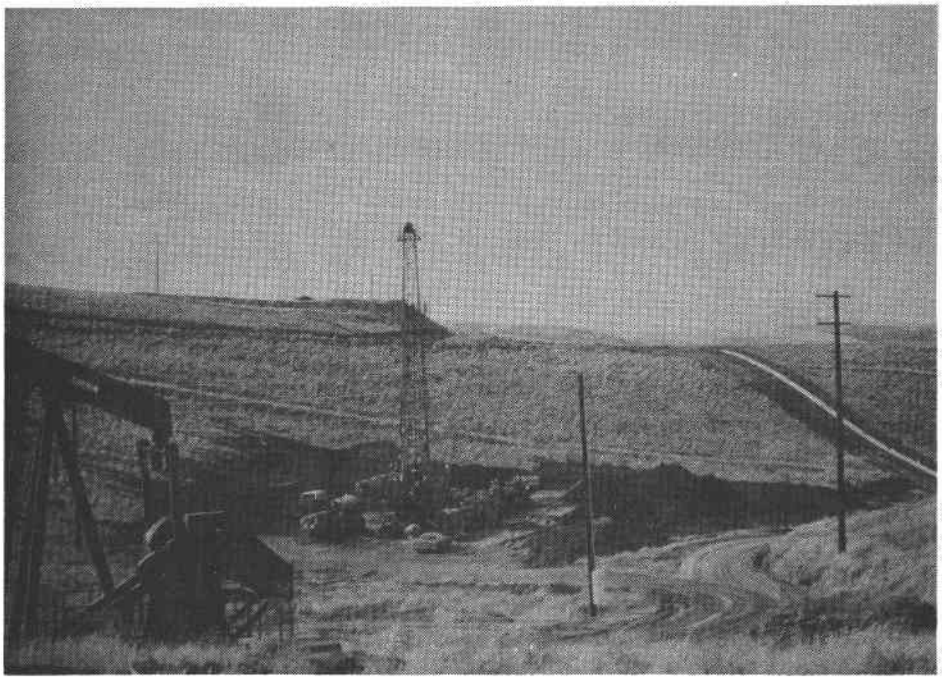
WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 3 MILES

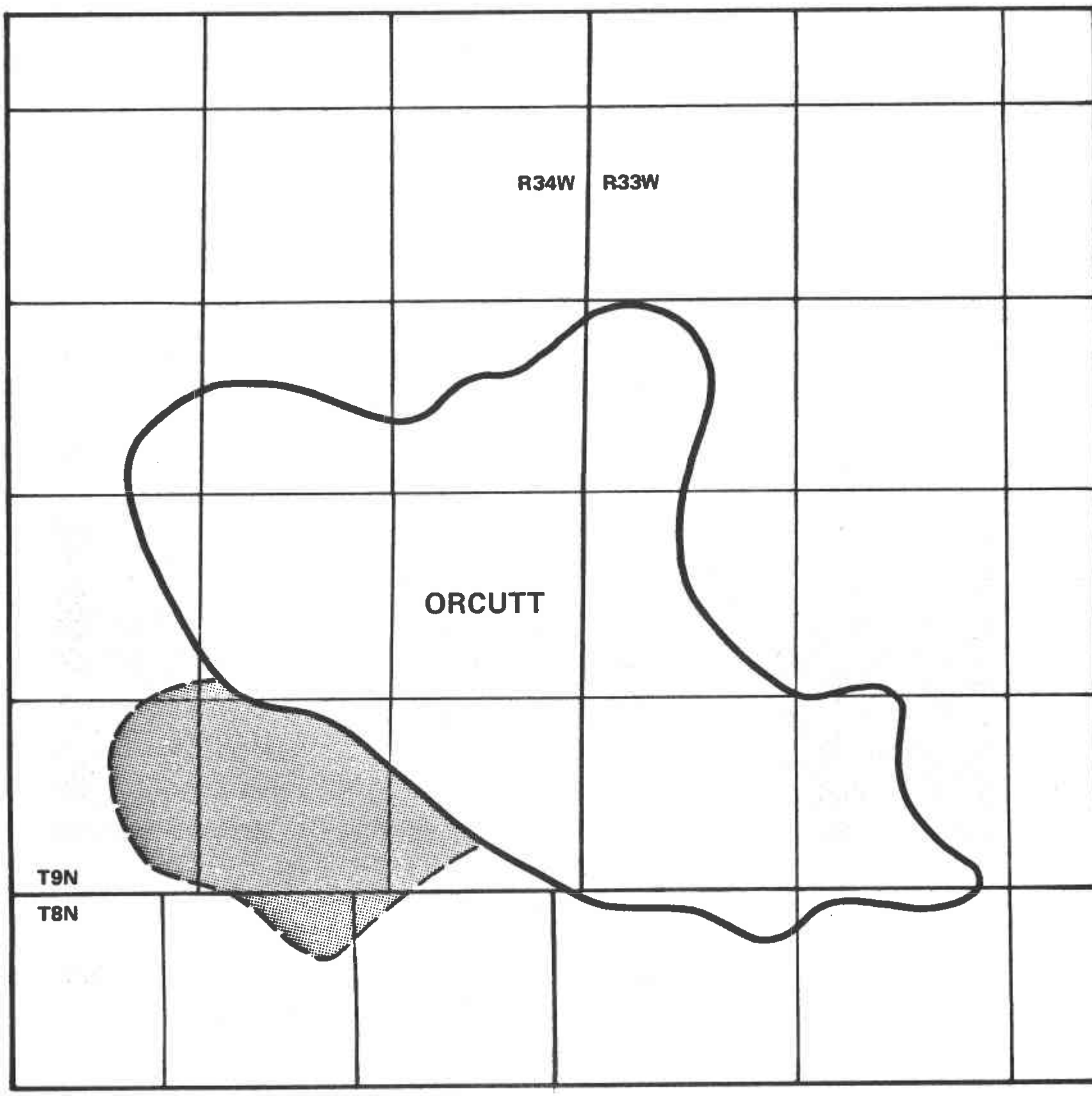
SCALE

FIGURE 8.21



Mount Poso. Workover rig and associated equipment near picture center. Steam lines to right.

FIGURE 8.22



ORCUTT – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

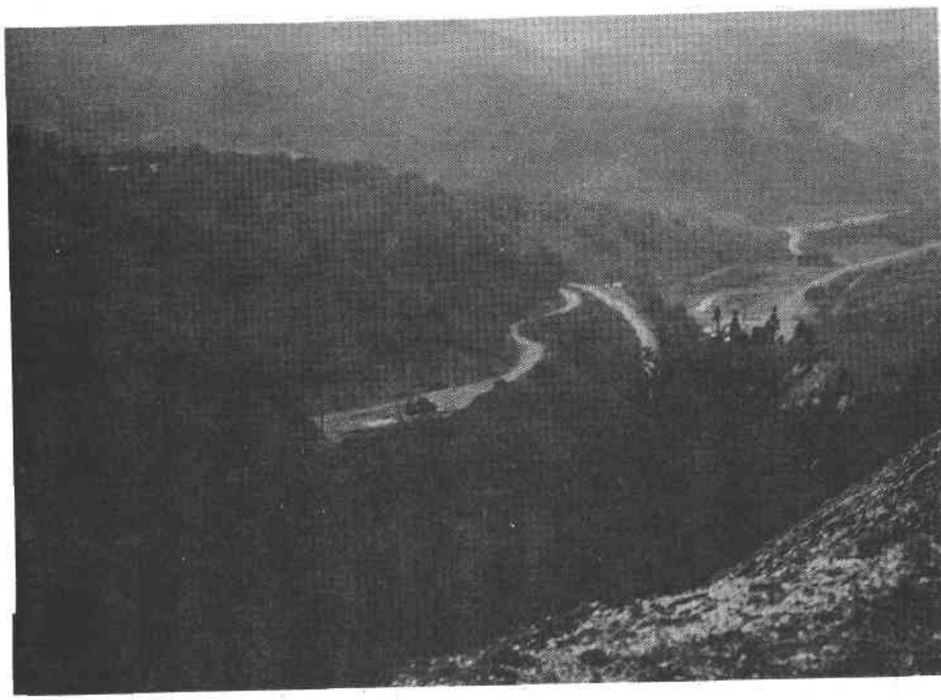
WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 3 MILES

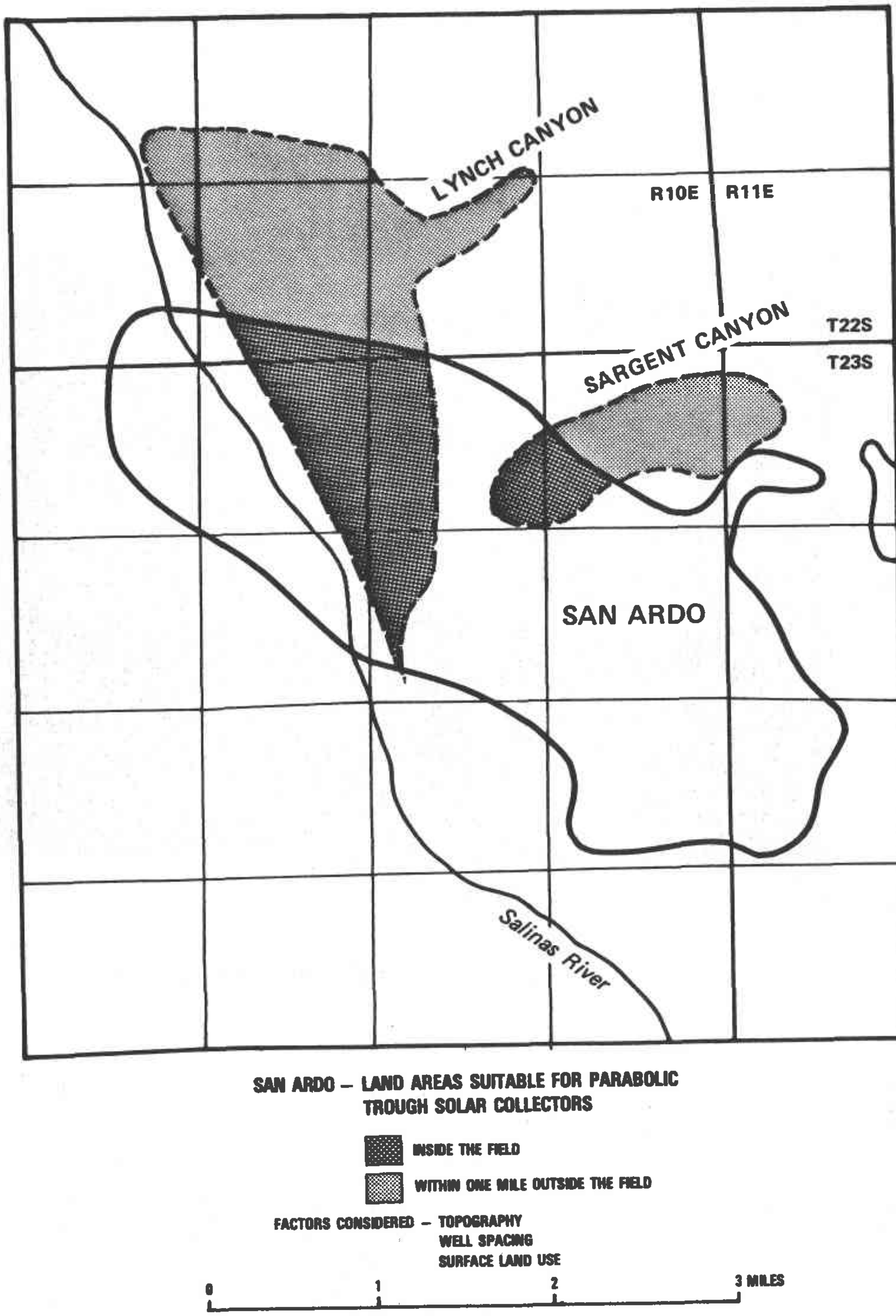
SCALE

FIGURE 8.23



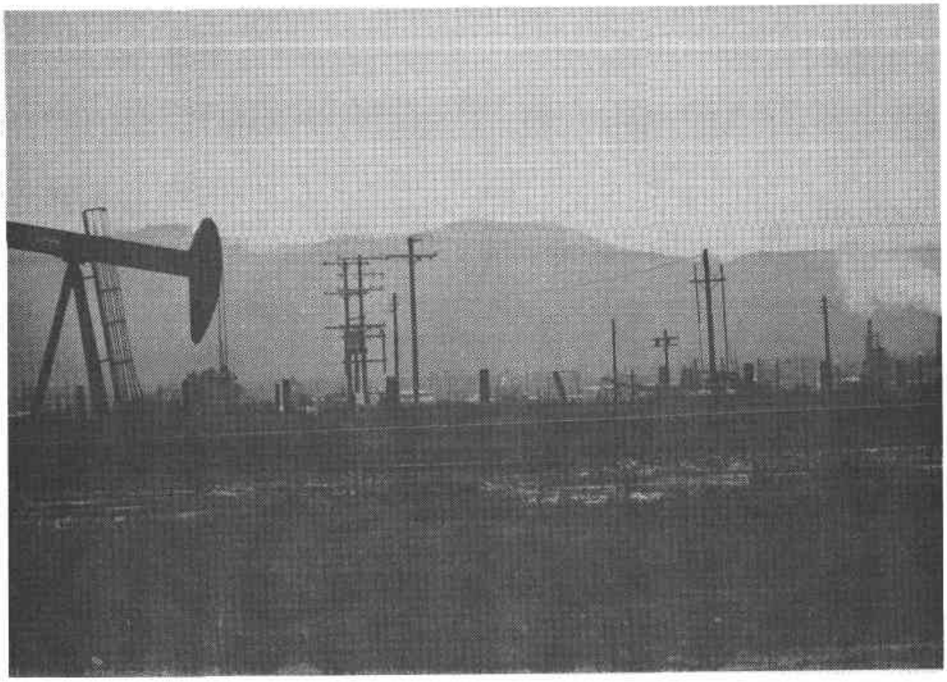
Orcutt. Mountainous area on a rainy day.

FIGURE 8.24



SAN ARDO – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

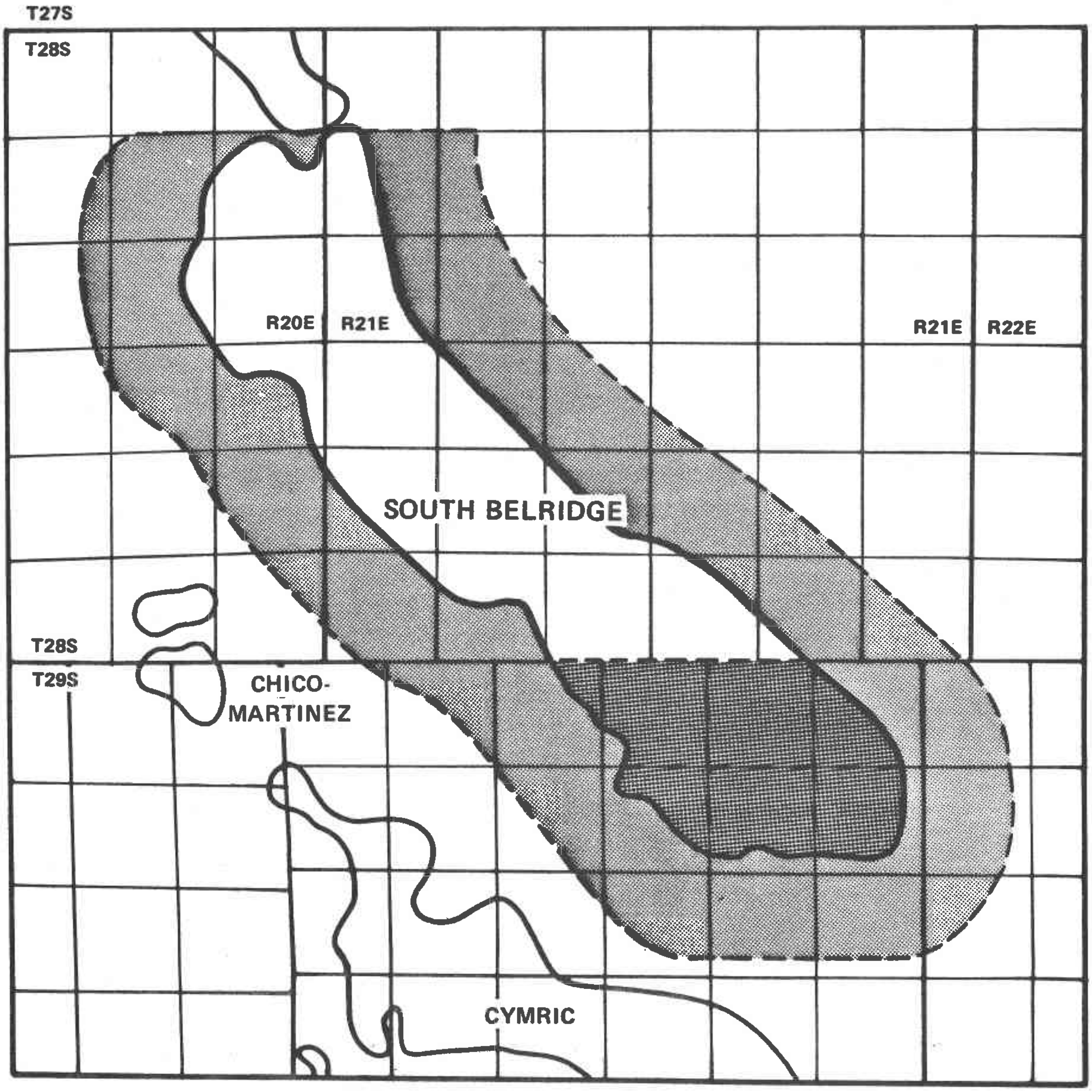
FIGURE 8.25



San Ardo. Flat portion of the field near the Salinas River.

San Ardo. Sargent Canyon during a rainstorm.

FIGURE 8.26



SOUTH BELRIDGE – LAND AREAS SUITABLE FOR PARABOLIC TROUGH SOLAR COLLECTORS

INSIDE THE FIELD

WITHIN ONE MILE OUTSIDE THE FIELD

FACTORS CONSIDERED – TOPOGRAPHY
WELL SPACING
SURFACE LAND USE

0 1 2 3 MILES

SCALE

FIGURE 8.27

South Belridge. Area of 2,529 M^2 (0.625 ac.) well spacing.

FIGURE 8.28

8.4 Screening of Fossil Alternatives and Feasibility of Diurnal Steaming

Under Task 1.1, a comparison was performed among the fuel and technology options available for conventional steam generation (oil, natural gas, coal and downhole boiler). Section 8.4.1 briefly discusses the results of a preliminary screening analysis on these options. For Task 4.4, the details of a program to understand the feasibility of diurnal (solar only) steaming are outlined. Section 8.4.2 describes an approach which would utilize both analysis (principally computer simulations) and field testing to ascertain the impacts of time varying solar phenomena.

The desire to perform a full test program per Section 8.4.2 may, however, be premature. If one assumes that any prudent operator would intially put a solar plant's output into an existing steam supply system (i.e., in parallel), then assuming the fossil system is large (several 14.7 MW (50 MBTU/Hr) units), one would have a solar-fossil hybrid system with a small, but measurable diurnal variation in energy flow. If solar meets the operator's criteria for economic and operational acceptance, then additional solar capacity would be added. In this gradual addition scenario, actual field experience (combined with appropriate laborabory simulations) would empirically determine the realistic limits on solar fraction. If an early, 100% solar grass roots installation were desirable, then the Section 8.4.2 program would be a necessity.

8.4.1 Screening-Type Comparison of Fossil Fuel Alternatives for Edison STEOR Pilot

8.4.1. Introduction

The purpose of this investigation was a preliminary screening of fossil fuel alternatives for an Edison STEOR pilot. This pilot would involve a hybrid system, utilizing both solar and fossil fuel energy. The screening consisted of comparing various fuel-generator systems to the present lease crude-fired generators used by Exxon Company, U. S. A. at Edison.

Factors taken into consideration in evaluation of the alternate systems included: (1) fuel availability, (2) fuel cost, (3) pollution control problems, (4) state of development of the system (would use in the pilot involve elements of further research and development?), (5) capital costs, and (6) probabilities for future use of the system in similar operations. Systems evaluated were coal- and gas-fired generators and downhole steam generators.

8.4.1.2 Lease Crude-Fired Generators

Exxon's first generator at Edison could burn oil containing a maximum of 1.1 percent sulfur by weight. Accordingly, Castaic Junction crude containing 1.8 percent sulfur is mixed with Edison lease crude containing 0.7 percent sulfur to stay within the limits required to limit pollutants emitted. The second generator has a scrubber designed for flue gas desulfurization and can burn crude containing as much as 1.7 percent sulfur. Present plans call for it and future generators to burn Edison lease crude.

Edison crude ranges from 16 to 19 °API (sp. gr. 0.9593 to 0.9402 at $16^{o}C$ 60°F) and has a heating value of 45.0 x 10^6 J/Kg (6.4-6.5 million Btu/bbl). Sulfur and nitrogen contents are each 0.71 weight percent. Mid-1980 selling price was \$25.07/bbl, or about \$3.69/10^9 J (\$3.89/MBtu).

Technology for oil field steam generators burning either natural gas or lease crude is well established. The major difference in units for the two fuels is in the burner. It should be noted that these units were originally designed for natural gas and some problems arise with the burning of lease crude. In particular, the higher temperatures experienced with the latter tend to cause failure of tubes, hangers, and refractory. Also, the sulfur content of the crude requires the use of a flue gas desulfurization unit. The present cost for a 7.3 MW (25 MBTU/hr) generator and associated flue gas desulfurization equipment is about \$460,000. Fuel burned in the generator typically is on the order of one-third of that produced.

8.4.1.3 Gas-Fired Generators

Natural gas has been a preferred fuel in the past because of its availability, low cost, and low pollution characteristics. Other advantages of the gas-fired unit over those using other fuels are low maintenance and zero fuel tankage requirements. However, decreasing natural gas availability has caused a shift to the use of lease crude. In a recent survey of Kern County, California, by the California Division of Oil and Gas, less than 13 percent of the generators were found to be gas fired. In many cases, this use of gas is tied to its availability from the same or a nearby lease.

Although produced gas from Exxon's Edison leases is insufficient to supply a 7.3 MW (25 MBTU/hr) generator, a gas-fired unit is still an option for the STEOR pilot. The feasibility of using lease gas to assist in firing a steam generator is being investigated. This gas can either be used in the form of a gas-oil fuel mixture or can be supplemented with purchased gas for a 100 percent gas-fired generator. A Pacific Lighting Service Company gas line runs within a few miles of Edison. Gas purchase prices run from \$3.32-55/10^9J to \$3.50-75/MBTU. Any gas purchase over $14.2x10^3M^3$ ($5x10^5ft^3$)/day must be approved by the California Public Utilities Commission. The full gas supply for a 7.3 MW (25 MBTU/hr) generator is over $19.8x10^3M^3$ ($7x10^5ft^3$)/day. A representative of Pacific Lighting Service Company expressed the opinion that no trouble should be encountered in receiving the necessary approval for the STEOR pilot. However, if one-third of the gas for the generator is supplied from the lease, purchase needs fall below the level requiring approval. Solar energy supply will reduce the purchase needs still further.

8.4.1.4 Coal-Fired Generators

Because of the large quantities of coal found in the United States, considerable interest has been expressed in using that material as fuel in steam generation for heavy oil recovery. In addition to concerns with deliverability and cost, a new type of steam generator is necessary.

Large coal reserves exist in Colorado, Wyoming, Utah, and New Mexico, and rail facilities are available for transport of the coal to Kern County. The Southern Pacific and Atchison, Topeka, and Santa Fe railways pass by the main area of the Edison field. The cost of coal at the field site is a strong function of the transportation costs. If sufficient quantities are used to justify a unit train (100 cars containing $9.1x10^4$Tonnes (10^5tons) of coal), then unit costs are relatively low. For smaller quantities, the price rises sharply. Examples of price per weight and energy are given as a function of type of transportation below for a $19.1x10^6$J/kg (8,227 BTU/lb) heating value Utah coal.

Delivery Method	Coal Price \$/Tonne	(\$/Ton)	Coal Price \$/10^9J	(\$/10^6BTU)
Unit train (regular)	\$27.83	(\$25.25)	\$1.45	(\$1.53)
Unit train (irregular)	\$38.01	(\$34.38)	\$1.98	(\$2.09)
Single or multiple cars	\$46.30-51.81	(\$42.00-47.00)	\$2.70-3.02	(\$2.85-3.19)

Coal for a 7.33MW $25x10^6$BTU/hr generator at Edison would not fit the unit train category, and would, therefore, cost \$2.70-3.02/10^9J (\$2.85-3.19 10^6BTU).

A strong emphasis is now being placed on use of fluidized beds of coal-limestone mixtures in coal-fired steam generators. Sulfur in the coal is efficiently removed by the limestone. In addition, the lower combustion temperature, about 871°C (1,600°F) as opposed to the 1,649°C (3,000°F) for conventional boilers, tends to reduce the formation of nitrogen oxides. These units can burn low-quality coal or other generally inferior fuels.

Tending to counteract the advantages mentioned above for coal-fired systems are several disadvantages, particularly for a small unit such as that at Edison. The complexity of the steam generator as compared to the usual gas- or oil-fired generator and the higher capital costs and materials handling problems emphasize the need for larger units, 14.7 to 29.4 MW (50-100 MBTU/Hr). The cost of a coal-fired generator and associated equipment is about seven to eight times that for an oil-fired generator plus associated fluid gas desulfurization equipment. Again, because of the more complex system, labor costs will probably run as much as 50 percent higher. In addition to the cost of coal, costs of limestone feed must be considered and disposal methods for the spent limestone developed. Finally, the effectiveness of the coal-fired units remains to be proved in the field.

8.4.1.5 Downhole Steam Generation

The primary incentive for development of a downhole steam generator has been the need for extending the effectiveness of steam injection processes to greater reservoir depths. Placing the generator down hole would avoid the problem of heat losses from a long wellbore. The basic challenge encountered is that of development of an effective steam generator for operation in the restricted confines of a wellbore. The device must be cost-effective and should not produce effluent that will plug the reservoir sands.

The Deep Steam Project, operated by Sandia Laboratories under a contract from the United States Department of Energy, has as its goal the production of 20,000 barrels per day of heavy oil by 1985. Initial field tests are set for 1980 in a Chevron well in the Kern River field.

M.C.R. Oil Recovery International Inc. has announced their development of a downhole steam generator. Earlier this year, they were finishing final fabrication of their second and largest prototype of 4.4 MW (15 MBTU/hr. capacity. Fuel for the unit is diesel oil. They are now seeking industry partners for field testing.

The downhole steam generator possesses several disadvantages with regard to its use as an alternative system for non-solar steam generation for the Edison STEOR pilot. First, it is still in the testing and development stage. As such, it will bring additional complications to the pilot. Secondly, one of the primary advantages for which it is designed, that of elimination of wellbore heat loss, will be at least restricted. The device is being developed for deeper wells than those in the Edison field. Also, there is a considerable question as to how surface injection (solar) and downhole injection (fossil fuel) might be accomplished in the same well. Finally, the presently-used fuel, diesel oil, will be relatively expensive.

8.4.1.6 Conclusions

A gas-fired steam generator is the optimum choice for the Edison STEOR pilot. Its relatively trouble-free operation will permit a greater concentration of effort on the newer solar technology. With no flue gas cleanup required and no premium on fuel price, it is preferred over the oil-fired generator.

An oil-fired generator is the second choice for the pilot. For the desired rate of steam generation, both it and the gas-fired unit are more cost effective than a coal-fired generator. The oil-fired generator has another possible advantage in that in the near-term future, it will probably be used more than the other systems.

The coal-fired generator and the downhole generator are still in testing-development stages, and therefore, should not be considered for the pilot. At the present time, coal units are not being planned in the 7.3 MW (25 MBTU/hr.) size.

8.4.2 Develop Program for Determining Feasibility of 100 Percent Solar at Edison

8.4.2.1 Introduction

One of the principal questions arising in consideration of use of solar energy in thermal enhanced oil recovery (STEOR) is whether a 100 percent solar system or a hybrid system is to be preferred. If feasible, the 100 percent solar system would obviously provide more of the advantages associated with solar energy. However, serious questions arise with regard to the effects of the diurnal nature of solar energy. Potential problems are:

(1) Effects of repeated temperature cycling on production equipment.

(2) Effects of diurnal steam injection on sand accumulation in the injection well.

(3) Effects of diurnal steam injection on recovery level, rate, and economics.

A desirable program for determining the feasibility of 100 percent solar systems will involve elements of method testing as well as of problem solving. Because of the varied nature of the expected problems, an optimum program may involve more than one study method. For the present considerations, emphasis was placed on mathematical simulations and field testing.

8.4.2.2 Effects of Repeated Temperature Cycling on Production Equipment

Surface equipment for a 100 percent STEOR operation will be subjected each day to temperature changes spanning the complete range from steam temperature to ambient temperature. Design for the uniquely solar parts of the system has taken such temperature cycling into account, but improvement and testing continue. With regard to wellheads and connections, some experience with temperature cycling has been gained during steam stimulation operations but not of the severity expected in a solar operation. The principal problem encountered, that of leaks through seals, has been handled by tightening of bolts or by replacement of the seals. The accessibility of the surface equipment facilitates such corrective measures and the testing of improved hardware.

The magnitude of the daily temperature cycles for the downhole equipment will decrease with time as the temperature of the region around the wellbore increases. Experience has been gained during steam stimulation operations concerning problems associated with such equipment as casing, packers, and expansion joints. Much is now known about methods of design to reduce the effects of such problems. However, the number of thermal strains during a 100 percent solar operation would be orders of magnitude greater than that for conventional steam injection operations. A numerical simulator has been used to predict casing stress history during a 100 percent solar operation. As expected, the stress oscillations decrease with time. Their magnitude, which is dependent upon the temperature changes, can be decreased markedly by use of insulation. The unanswered question is the long-term effect of thousands of temperature cycles, however small. The ultimate answer to this question would be reached through field testing. Comments on field test alternatives will be made later.

8.4.2.3 Effects of Diurnal Steam Injection on Sand Accumulation in the Injection Well

Past experience has shown that interruptions of steam injection can lead to accumulations of sand in the injection well. Exxon has handled this problem for producing intervals up to 15 M. (50 ft.) in steam simulation operations through use of careful gravel-packing techniques. These techniques involve an outside gravel pack accomplished by the sand oil squeeze (SOS) technique and an inside gravel pack. The question still remains, however, as to the long-term effects of multiple solar cycles. This problem is complicated by the tendency of steam to dissolve or reduce the size of the packing gravel. The answer to the question as to the severity of this problem and any needed solutions will be found only through extensive field experience.

8.4.2.4 Effects of Diurnal Steam Injection on Recovery Level, Rate, and Economics

Reservoir questions regarding diurnal steam injection involve the overall average steam injection rate achievable, the effects of the overnight interruptions of steam injection, and production characteristics. Apart from field experience, a numerical reservoir simulator is best suited to study such effects. It should be emphasized that an effective reservoir simulator, such as Exxon's GPTHERM, should be backed up by engineers experienced both in mathematical simulation and in applications of steam injection for enhanced oil recovery.

Maintenance of an average solar steam injection rate equal to an optimum value for continuous injection is dependent upon two principal factors. First, there is the question as to whether ample solar steam generation capacity exists to supply steam at a rate two to three times the desired average rate. This is a function of land availability and of capital costs for the necessary collector system. If this hurdle is passed, then a more difficult question must be faced, namely, whether parabolic trough solar collectors can supply steam at the pressure needed for the higher injection rates. Since two factors are acting overnight to lower the reservoir pressure, needed steam injection pressure is not necessarily that predicted from simple ratios of reservoir pressure drops and injection rates. First, production continues overnight with no steam injection; and second, heat dispersion and resulting steam condensation can also reduce pressure. As indicated below, pressure needed to supply desired day injection rates can be estimated by numerical reservoir simulation. If parabolic trough solar collectors cannot supply steam at the required pressures, then lower average rates must be accepted.

Numerical reservoir simulations can be used to show whether or not intermittent steam injection gives different reservoir behavior than does continuous steam injection at the same average rate. There has been some speculation that the intermittent injection would lead to more rapid and excessive fingering and to an earlier steam breakthrough. Since there is equal time in the two cases for the lateral heat transmission that inhibits finger growth, it is doubtful that significant differences would be observed. Nevertheless, the principle can be tested by comparison of results from two-dimensional cross-section calculations.

The cross-section calculations mentioned above will also give an idea of injection pressure requirements for the diurnal injection. More precise estimations of these pressure requirements can be made, however, by use of a three-dimensional simulation. If the desired pressure is not achievable with parabolic trough solar collectors, then lower average rates must be used in the field. At least one other three-dimensional simulation must be made to verify this pressure behavior.

Finally, if a lower average rate is required, a third cross-section calculation must be made at this lower rate so that results can be compared with those from the first two cross-section calculations.

Simulations required can then be summarized as follows: (1) Two cross-section calculations to determine reservoir effects of intermittent injection. (2) Two three-dimensional calculations to determine injection pressure effects for the intermittent case. (3) One additional cross-section calculation, if lower than desired rates are required, to estimate the effects of these lower rates. This program would involve costs of \$10,000 for computer time and \$15,000 for manpower.

8.4.2.5 Field Pilot Testing of 100 Percent Solar Thermal Enhanced Oil Recovery

The principal items for which field testing of 100 percent solar enhanced oil recovery might be desirable are the effects of long-term temperature cycling on production equipment and on sand accumulation in the injection well. To a high degree, these field projects would consist of continuing efforts to devise solutions to operating problems and to gain experience in dealing with such problems. Multiple injection wells should be used to provide some measure of statistical validity to the results.

The minimum pilot recommended for testing the above factors in 100 percent STEOR would contain three injectors. Since injection would continue for approximately one year, these might be a part of a larger array of five spots in which steam floods were being conducted. Regardless, one 7.3MW (25 MBtu/hr steam generator would be dedicated to the three test wells. Steam would be provided sequentially to the wells on a time schedule approximating changes in solar rates observed during the day. A testing time of one year is suggested to provide ample opportunity for long-term effects of the temperature cycling to be observed.

Cost of purchase and installation of the steam generator is presently about $900,000. Operation of the pilot will bring the total cost to about $3,000,000.

8.4.2.6 Conclusions

In determining the feasibility of 100 percent solar thermal enhanced oil recovery, some of the major tests can be accomplished by theoretical methods. First, the availability of sufficient solar capacity at acceptable costs must be determined. Next, it must be determined whether or not the steam pressure generated by parabolic trough solar collectors will be sufficient to provide the high daytime injection rates necessary to give the desired average injection rate. Mathematical simulations with a numerical reservoir simulator should help to determine oil recovery problems, if any, due to intermittent steam injection. If the average solar injection rate is lower than the desired value, numerical reservoir simulation can quantify the penalties that this entails. If the project passes these hurdles, the questions remaining have to do with equipment and sanding problems due to temperature cycling. The cost of a test to quantify these factors appears to be quite high. As a result, one may choose to adopt the best preventive measures known at the present and learn from experience as applications of solar technology to steam injection processes increase.

8.4.3 Air Quality Improvement

The reduction in emissions attributed to a solar hybird system is in direct proportion to the fraction of heat supplied by solar. Resulting air quality improvements depend on the relative contribution of TEOR to all other emissions sources. Currently, this factor is estimated to be in the range of 0.2 to 0.5. Thus, if the solar fraction in TEOR is 0.3, the resulting improvement in air quality would be expected to be between 6% and 15%. See Appendix J for further discussion of air quality at Edison.

8.5. Analyze Financing and Incentives

8.5.0 INTRODUCTION

This activity examined the impact of various financing and incentive measures on the economic attractiveness of STEOR applications. The incentives considered included: solar tax credits, accelerated depreciation and the Economic Regulatory Administration EOR front-end pricing program, Tertiary Incentive Revenue (10 CFR 212-78) (8-65). Two financing options were reviewed for their feasibility and desirability: leveraged leasing and tax-free pollution control revenue bonds.

All of these measures have the theoretical potential of reducing the capital cost component in solar energy lifetime costs. They differ in the level of benefits they provide, the timing of their impacts, the degree of the administrative burdens placed upon the users and the amount of financial control they give the users over their systems.

8.5.1 FINDINGS

Our quantitative analysis developed a basis for ranking the economic effectiveness of the various incentives. It indicates that the most effective incentive is the Economic Regulatory Administration's Tertiary Incentive Revenue (T.I.R.). This benefit can be used during construction to provide "front end financing". Second in relative effectiveness are the various US and California tax credits for investments in solar equipment. These can be claimed in the year of initial operation. On an absolute basis, the magnitude of T.I.R. exceeds the credits. More liberal (shorter tax life) depreciation approaches , if legislated, would have a lower impact than either credits or T.I.R. For example, the benefit of first year expensing, if added to the tax credits, is less than the benefit of T.I.R. if added to the same credits.

Although the government incentives are available and apparently additive, some uncertainties do exist. The present California solar tax credit expires at year end (8-66). Several bills have been introduced to extend these credits, and passage of one or more is expected (8-67). However, unexpected legislative problems could still occur which would delay enactment. The existing oil price control statutes give the President the power to authorize immediate price decontrol at any time (8-68). The T.I.R. program expires whenever final decontrol occurs.

Our review of financing options indicated a low level of current feasibility. Assuming a California location, the only pollution control bonding authority available to STEOR today appears to be the limited amount of funds set aside under a small business provision. It also appears that Solar TEOR equipment would fail to meet the strict Internal Revenue Code qualifications for pollution control hardware. The major issue in evaluating leveraged leasing (project financing) is the question of the potential credit worthiness of any near term STEOR project. Assuming that iron clad guarantees of principal (which if required would defeat the purpose of "off balance sheet financing") are unavailable, a significant number of extraordinary risk factors are present today in STEOR which would severely penalize any loan evaluation.

This risk problem is not unique to STEOR, most new technologies are usually considered to be beyond the realm of a credit risk and are properly classified as equity risks. While a 100% equity backed (unleveraged) lease is a possibility, it is likely to offer little economic advantage to the potential EOR solar user--oil field operator. Even if the solar technology were to become highly developed, the use of a leveraged lease in combination with an uncertain economic life extractive resource project (TEOR) could still be a difficult financial proposition for a prudent lender to support.

If, however, these financing problems could be solved, there would remain the question of what would be the measure of benefit to the sponsoring firm. A highly leveraged position (large loan fraction) in the opinion of some financial authorities, may offer only limited or no economic advantages. The impact depends on whether or not the financial markets downgrade the ratings and increase the returns demanded on the firm's other financial instruments. Thus, high loan fractions may not necessarily lower the weighted average cost of capital (8-69). These findings suggest that leveraging, in general, does not appear to be a panacea for solar's relative financial unattractiveness.

8.5.2 ECONOMIC ANALYSIS

A discounted cash flow model and calculational algorithm were developed for STEOR projects. Using a baseline assumption set, the relative sensitivity of the project's economics was examined given the project's input parameters. If one assumes high government incentives, then solar operating costs and the rate of oil price growth appear as highly sensitive inputs to the determination of breakeven equipment cost. In low incentive situations, allowable solar costs depend principally upon solar capital costs and discount rates.

8.5.2.1 Framework

An updated version of the model and algorithm presented in Volume IV of our Business and Technical proposal were utilized in this study. (See Appendix I.2).

The model was designed to carry out a side-by-side comparison of a 100% fossil-fired base case (fossil) and a solar-fossil hybrid case (hybrid). Both systems were constrained to deliver identical net steam outputs (after flue gas desulphurization) to a common steam header. While the oil field was assumed to use the steam for steam drive operations, no credit (debit) was taken for the value of any added (or reduced) production. This framework tacitly assumed that any time varying effects in steaming rate would not materially affect downstream production. It also assumed that a fossil boiler was continuously scalable for purposes of comparison. Our scaling was as follows:

If system (2) is larger than system (1) then:

$$\text{Capital (2)} = \left(\frac{\text{Steam (2)}}{\text{Steam (1)}}\right)^{0.6} * \text{Capital (1)}$$

$$\text{Operating (2)} = \left(\frac{\text{Steam (2)}}{\text{Steam (1)}}\right)^{1.0} * \text{Operating (1)}$$

(The 0.6 capital scaling factor represented an emprical observation of typical cost scaleups exhibited in equipment used by process industries) (8-70).

The economic algorithm generated several forms of output:

1. Annual after tax cash flows
2. Net Present Values (NPV)
3. Internal Rate of Return on Incremental Solar Capital Investments (IRR)
4. Government grants to provide a specified rate of return
5. Design to cost ($\$/M^2$) ($\$/ft^2$) numbers for combinations of input parameters
6. Annualized (or levelized) energy costs) given an economic life and discount rate.

8.5.2.2 Assumptions

The analysis and algorithm rely on a number of assumptions. For those assumptions which were based upon uncertain information, a parametric analysis was suggested. Other assumptions reflected the state-of-the-art, published data, etc. We have separated our assumptions into 5 groups:

1. Process & Environmental Data
2. Economic Data
3. Tax and Accounting Treatment
4. Fossil-Fired Case Data
5. Solar-Fossil Hybrid Case Data

8.5.2.2.1 Process and Environmental Data

We assumed that it was possible to exclude considerations of ambient air quality (AAQ) limits (excepting fluegas SO_X scrubbers) and downstream process effects from our model. Specifically, we assumed:

- An economically attractive return is available, if Edison field steaming capacity is expanded by up to 14.7 MW (50 MBTU/hr).

- There will not be any problems with this additional fossil capacity's ability to meet AAQ Standards over a 20 year period using current flue gas desulphurization technology.

- Any hybrid case diurnal steam flow variations experienced will have no measureable impact on yearly reservoir enhanced production, or on non-boiler operating costs.

- As a consequence of the above, there will be no need to examine any downstream revenues or fluid gathering and processing equipment costs.

- Since the two cases are defined to have equal production rates, we assumed that no differential Ad Valorem or property tax impacts would occur (except that fuel must be costed net of Ad Valorem Tax (Section 8.1)).

8.5.2.2.2 Economic Data

Price levels and rates of change were assumed as follows:

o <u>GNP Implicit Price Deflator</u> - Used for capital and nonfuel operating costs:

Year	Total Annual Rate	Estimate Basis
1979	8.9%	Conference Board Statistical Bulletin (4/80)
1980	10 %	Conference Board Estimates (4/80)
1981	10 %	plus upward adjustments
1982 to End of Life	7 %	Proposed Baseline, original Administration Guidelines

In our original proposal we used a 7% rate for both near term and long term inflation. Its value was implicit in the selection of a 15% discount rate. Here we assume that the current inflationary period will impact the bulk our capital costs, but a more acceptable 7% baseline will be achieved by 1982, and will be representative of the long range expectations which existed before the current jump.

o <u>World Oil Prices</u> - used to estimate Crude Oil-fired boiler fuel costs

We have continued to assume a constant 3% real price growth for oil over the life of the project. <u>This assumption is neither an Exxon forecast nor an Exxon endorsed forecast.</u> It is based, however, upon the nearest integer average value of DOE real price growth projections as discussed in Section 8.1.

For reference purposes, our projected constant and current dollar world oil prices per barrel from section 8.1 were:

DOE Projection Based

<u>World Oil Prices</u>

Year	Constant $1980	Current Year Dollars
1980	$30.00	$ 30.00
1985	$34.15	$ 48.32
1990	$40.78	$ 77.81
1995	$46.22	$125.32
2000	$52.39	$201.82

The world oil price presumed a 10% annual inflation (3% real growth) above the 1980 level. We used a 7% GNP deflator throughout. This deflator smooths out the effects of near term 10% rates and the lower 6.5% rates which occur after 1985 (8-71).

o Fuel Costs

The table which follows was copied from Section 8.1 and shows the current dollar per barrel fuel costs for heavy crude at various Windfall Profits Tax (WPT) Levels. Our algorithm included the WPT tax explicity. Our calculations have looked at both Tier Two or Tier Three which set the lower and upper limits on Edison fuel costs respectively:

Prices Net of Ad Valorem and Royalty Interest

			Fuel Costs		
Year	World Price	Quality Debit	No W.P. Tax	Tier 2	Tier 3
1980	$ 30.00	$ 27.00	$ 23.60	$ 17.92	$ 21.14
1985	$ 48.32	$ 43.48	$ 38.02	$ 27.10	$ 33.44
1990	$ 77.81	$ 70.03	$ 61.22	$ 41.17	$ 53.79
1995	$125.32	$112.79	$ 98.60	$ 98.60	$ 98.60
2000	$201.82	$181.64	$158.79	$158.79	$158.79

o Electricity Prices

We assumed 4¢/Kwh as a 1980 rate and total inflation continuing at 2% (real) above the 7% base price deflator growth. This was unchanged from our proposal (8-72).

8.5.2.2.3 Tax and Accounting Treatment

o Tax Rates

+ Federal Income	46%
+ California State Income	9%
+ Combined Rate	50.86% (State is deductible from federal)
+ Property Tax	In Ad Valorem Tax
+ Ad Valorem	6% is a representative number for Edison. The value is the quotient of expected tax divided by expected revenue. It is not the tax rate per se.

o Depreciation

Section 167 of the Internal Revenue Code permits the use of Asset Depreciation Range (ADR) techniques for equipment employed in the exploration and production of oil and natural gas. Exxon uses the following accelerated depreciation treatment:

o Mimimum Lifetime	11 years
o Averaging Convention:	
+ Six months for first calendar year	Double Declining Balance
+ Twelve months for second calendar year	Double Declining Balance
+ To end of life	Sum-of-Years Digits

We assumed zero salvage values for all equipment. Although current California statutes do not permit simultaneous claiming of depreciation and the California Energy Solar Tax Credit, we have assumed that any tax credit reenactment will remove this obstacle (8-73).

o <u>Tax Credits</u>

+ U.S. Investment Tax Credit (both fossil and solar systems)	10%
+ U.S. Energy Tax Credit (solar system only, reenacted and increased by the WPT legislation)	15%
+ Effective California Solar Energy Tax Credit (AB 2100)	5.4%
+ Combined Credits	30.4%

Our reviews indicated that the U.S. and California credits are generally deemed to be additive. The present rules for the 25% gross California Solar Energy Tax Credit have required the deduction of any U.S. Energy Credit (i.e., 25%-15% = 10%). The after tax benefit of this 10% must be further reduced to account for the fact that a smaller state tax deduction was allowable on the federal return. Subtracting the increased federal tax (at 46%) leaves 54% of 10% or 5.4% as shown.

o <u>E.R.A. Tertiary Incentive Revenue</u>

The ERA rules for crude oil price allocation in 10CFR212 part 78, provide a front-end incentive called "Tertiary Incentive Revenue". This is incremental ordinary income (IRS Code Sections 61 and 263) to a producer which comes from the first sales of otherwise controlled price oil (lower or upper tier) which is sold at market clearing prices. The oil need not come from the field where the qualifying tertiary project is located. Eligibility for the program is based on the project's reservoir properties and on the EOR techniques proposed. The effect of the E.R.A. rules as recently amended to take account of the Windfall Profits Tax passed this year, is summarized below: (See Reference 8-65).

Category	% of "Solar Boiler" Cost	
"Qualifying Expense"	100%	
"Allowable Expense"	75%	
"T.I.R." (<u>net</u> of WPT and local production taxes)	75%	(Equals Allowable Expense)
Income Taxes (to US at 46% plus 2% to States)	(36%)	
Net T.I.R.	39%	

Full capture of this T.I.R. benefit will require completion of front-end expenditures prior to Sept. 30, 1981, the last day of price controls. (The preamble to the latest ERA technical amendment, however, indicates that prepayment may occur in some cases) (8-74). Another concern is the amount of oil which would need to be decontrolled to recoup the TIR. For an example solar project with: a $10 million capital cost, a 15 month construction period beginning in June 1980, an "S" curve expenditure profile, and world oil prices following the projections of section 8.1; the volumes of oil are as follows:

Controlled Price	Total BBLS	Peak Month In BBLS	Average TIR Per BBL
Lower Tier	680,000	60,300	$11.03
Upper Tier	2,746,000	270,300	$ 3.64

In each case a series of calculations was made using the TIR rule, the WPT, an average local production or severance tax per Lewin Associates (8-75) and published DOE upper/lower tier ceiling prices (8-76). A sample calculation follows:

Month = June 80 Investment = 2% (or $200,000)

Category	Amount Per Barrel
"World Price"	$31.22
11% Local Tax	($ 3.43)
70% WPT (from $13.39 base)	($10.08)
Lower Tier Price	($ 7.11)
"EFFECTIVE TIR"	$10.60

$$\text{Barrels} = \frac{\$200{,}000 \times 0.75}{\$10.60/\text{BBL}} = 14{,}151 \text{ BBL}$$

To meet this monthly figure, a field production of 472 BBL/Day would be required. For the peak expenditure months, the daily field production levels would have to be between about 2,100 and 9,000 BBL/Day for lower and upper tier oil respectively.

o <u>Startup and End-Of-Life Conventions</u>

We simplified our analysis by assuming that all investments, tax credits and TIR occur in year zero. All subsequent years (1982-2001) are treated as operating years. We assumed a twenty year calculation period. This represents a conservative estimate of both the reservoir life (assuming tests of steam drive are favorable) and the likely economically useful life of solar equipment.

8.5.2.2.4 <u>Fossil Case Data</u>

o Struthers OH-25 Steamer & Auxilliaries

+ Rated Output	7.33MW (25 MBTU/hr)
+ Service Factor	95% (Fixed Location)
+ Annual Output	$61 \times 10^3 \frac{MWH}{Yr}$ ($208{,}050 \frac{MBTU}{Yr}$)
+ Oil Net Heating Value	$10.93 \frac{MWH}{M^3}$ ($5.93 \frac{MBTU}{BBL}$)
+ Efficiency	82% (Average)
+ Output Steam Quality	80%
+ Crude Oil Input/Steam Output (BBL/BBL)	0.0729
+ Scrubber Useage	8.7% of gross steam
+ Electric Auxiliaries	$1.46 \times 10^3 \frac{(MWH)}{Yr}$ ($4{,}100 \frac{MBTU}{Yr}$)
+ Fuel Usage	$6{,}802 \frac{M^3}{Yr}$ ($42{,}786 \frac{BBL}{Yr}$)

These data are based on information supplied by Struthers Wells to ER&E and EUSA (8-77, 78).

o Capital Costs

The basic OH-25 unit plus scrubber and accessories costs are:

+ Boiler	\$240,000
+ Water Treatment	\$260,000
+ FGD Scrubber	\$220,000
+ Misc. Support	\$165,000
Total	\$885,000

(Costs to nearest thousand \$1980)
(A 1% overhead charge is applied in year 1 (1982)

o Variable Operating Costs (8-80)

The following consumables are used to produce 1590.0 M^3 (10,000 BBL (feedwater equivalent)) of steam which goes to the field and scrubber (8.7% of total). In \$1980 the values are:

+ Water	\$ 163	
+ Chemicals	\$ 392	
+ Scrubber Chemicals	\$ 207	
+ Caustic	\$ 436	
+ Scrubber Waste Disposal	\$ 545	
	\$1,743	(\$1,188 for scrubber)

If one assumes the fossil boiler adds about 2.410^6J/kg (1012 BTU/lb) to the feedwater, then, each 1.1 x 10^9J (million BTU's) makes 0.45 M^3 at 998.4 kg/M^3 (2.82 BBL at 350 lb/BBL) of steam. The energy produced before scrubbing corresponds to 93,400 M^3/YR (587,400 BBLS/YR). The resulting annual costs are:

Total System	\$102,380. (includes Scrubber)
Scrubber Only:	\$ 69,780.

o Other Costs (8-81)

There are certain other costs which are associated with the boiler operations. In \$1980, these are:

+ Operator - 1/2 man, 7 days/week \$25,047
+ Maintenance - \$21,780
+ Overhead - 7% on all variable and fixed operating costs

8.5.2.2.5 Solar Hybrid Case Data

o The baseline solar fossil hybrid system uses a flash-separator/ preheat with storage concept. The design is described in Section 5. The solar system's performance is:

Characteristics are:

+ Rated Output	$19.22 \times 10^3 \frac{MWH}{YR}$ (65.6×10^9 BTU/YR)
+ Service Factor	95%
+ Effective Annual Output	$18.26 \times 10^3 \frac{MWH}{YR}$ (62.32×10^9 BTU/YR)
+ Efficiency	37.1%
+ Maximum Heat Rate	11.92 MW (40.7 x MBTU/HR)
+ Output Steam Quality	80%
+ Collector Area	22,830 M^2 (245,655 ft^2)
+ Land Displaced	97×10^3 M^2 (24 acres)
+ Annual Parisitic Power for pumps and drives	$1.2 \times 10^3 \frac{MWH}{YR}$ (4.1×10^9 BTU/YR)

The fossil backup system is assumed to be identical to the base case system. It's output is constrained to give the same net total energy per year:

+ Backup System Annual Output including steam to scrubber	$40.9 \times 10^3 \frac{MWH}{YR}$ (139,790 $\frac{MBTU}{YR}$)
+ Backup System Auxiliaries	$1.46 \times 10^3 \frac{MWH}{YR}$ (4,100 $\frac{MBTU}{YR}$)
+ Consumables and Scrubber Usage	Proportional on net annual output of fossil section
+ Backup fuel usage	4,570 $\frac{M^3}{YR}$ (28,748 $\frac{BBL}{YR}$) (same efficiency and heat rate as fossil system)

- o <u>Capital Costs</u>

These costs were developed by Foster Wheeler from the Preliminary Design in Section 6:

		$\$/M^2$	$(\$/Ft^2)$
+ Collectors	\$ 5,056,100	\$221	(\$20.5)
+ Collector Installation	\$ 2,325,918	\$102	(\$ 9.5)
+ Site Preparation, Foundations	\$ 835,600	\$ 37	(\$ 3.4)
+ Controls & Electrical	\$ 3,150,831	\$138	(\$12.8)
+ Pumps and Tanks	\$ 219,517	\$ 10	(\$ 0.9)
+ Piping & Insulation (includes steam mains)	\$ 1,958,453	\$ 86	(\$ 8.0)
+ Other Home Office & Etc.	1,850,071	\$ 81	(\$ 7.5)
+ Total	\$15,396,490	\$674 (2)	(\$62.68)
+ Capital Overhead	1% in 1982		

Notes: 1. Indirects are allocated to direct labor charges.

2. Per M^2 does not add due to rounding.

- o <u>Solar-Hybrid Operating Costs</u>

The solar-hybrid system operating costs were estimated by Foster Wheeler in Section 6 to be the following (\$1980):

+ Maintenance Manpower and Materials (3% of collector materials and 1% of balance)	$264,000	(Manpower for maintenance is 7325 man hours per year).
+ Solar Electricity (4¢/Kwh)	$ 48,052	
+ Operating Manpower for boiler	$ 25,047	(Same as Base Case)
+ Boiler Electricity (linear reduction for reduced firing)	$ 39,135	
+ Boiler Maintenance	$ 21,780	(Same as Base Case)
+ Boiler Consumables (linear reduction in scrubber consumables)	$ 55,434	
Sub Total	$453,448	
+ Overhead	7% of direct expenses was added to the above estimates before finding cash flows in Table 8.15.	

8.5.2.3 Baseline Economics and Sensitivities

The STEOR economics algorithm was used to calculate the net present value and effective levelized cost of energy for the flash separator/preheat storage design. Assuming a Tier Two (stripper field, 60% Windfall Profits Tax), the results were:

System	NPV ($1000's)	IRR (%)	Levelized Cost $/$10^9$J	($/MBTU)	
Fossil	($7,872)	-	$6.27	($6.62)	
Solar-Hybrid	($7,702)	-	$6.14	($6.48)	
Differential	$ 170	15.85%	$5.74	($6.06)	(Solar Increment)

Table 8.15 shows the annual cash flows for the two systems, fossil and solar fossil hybrid. (System capital costs are in escalated $1981, and first year operating costs include 7% overhead and escalation to $1982). The 1981 to 2001 values are net cash after-tax expenses. As can be seen, the

TABLE 8.15

ECONOMIC COMPARISON OF FOSSIL AND SOLAR HYBRID SYSTEMS

```
*************************************************************
STEORE CASE # 1                                RESERVOIR MODE =NREV

                    VARIABLE PARAMETER SUMMARY

 OIL PRICE /BBL=$            32.67   OIL INFLATOR=                1.100
 CAPITAL COST %=             15.00   ASSET TAX LIFE=             11.000
 HYBRID EFFICIENCY           82.00   MBTU /BBL =                  5.930
 ASSET REAL LIFE=            20.00   BACKUP MBTU/YR=        139,790.000
 SOLAR MBTU/YR=          62,320.00   BASE SRVC FCTR %=           95.000
***
 SOLAR O&M % OF INV           1.89   ELECT PWR SOLAR =$      64,270.000
 FOSSIL SYS COST=$      973,500.00   START YEAR:1982+=            0.000
 BACKUP SYS COST=$      973,500.00   SOLAR ARRAY SQ FT      245,655.000
 SOLAR COST/SQ FT =          68.94   FRACTION ITC + TIR           0.694
 SYSTEM PRICE=       +$17,908,956.

    ANNUAL CASH FLOWS OVER THE ASSET LIFE

    YEAR    BASE CASE      HYBRID CASE
    1981    -  $876,150.   - $6,058,399.
    1982    -  $460,946.   +    $993,470.
    1983    -  $519,241.   +    $733,816.
    1984    -  $577,428.   +    $547,886.
    1985    -  $640,096.   +    $357,743.
    1986    -  $707,650.   +    $163,026.
    1987    -  $780,533.   -     $36,659.
    1988    -  $859,229.   -    $241,743.
    1989    -  $944,266.   -    $452,690.
    1990    -$1,036,222.   -    $670,010.
    1991    -$1,758,237.   - $1,312,523.
    1992    -$1,936,829.   - $1,591,899.
    1993    -$2,132,102.   - $1,884,624.
***
    1994    -$2,338,327.   - $2,056,462.
    1995    -$2,564,665.   - $2,244,289.
    1996    -$2,813,091.   - $2,449,619.
    1997    -$3,085,772.   - $2,674,111.
    1998    -$3,385,093.   - $2,919,580.
    1999    -$3,713,669.   - $3,188,019.
    2000    -$4,074,378.   - $3,481,609.
    2001    -$4,470,378.   - $3,802,744.

    NPV(BASE)          NPV(HYBRID)
    - $7,872,245.      - $7,701,957.
    NPV (NET) =        +    $170,288.

  BASE CASE ANNUALIZED COST    = $    6.62 / MBTU
  HYBRID CASE ANNUALIZED COST  = $    6.48 / MBTU
```

$6.27/10^9J

$6.14/10^9J

hybrid system actually generates positive cash flows through 1986 from the excess depreciation deductions which are assumed to be applied to reduce taxes owed upon other revenues.

The baseline scenario assumes many parameters which are subject to greater or lesser variability. Table 8.16, summarizes the economic performance of the preliminary design in terms of the NPV, and levelized energy cost if the project. The sensitivity effects listed look at credits, tax lives, oil price effects, investment amount and lifetime, operating costs and performance, and the discount rate. From an overall standpoint, the NPV can vary from a negative $7.3 million if only the US credits are available, to a high of $2.6 million if a one year tax writeoff were permitted under new legislation. Hybrid system (Solar plus fossil) levelized energy costs range from $4 to $12/10^{9}J ($6 to $13/MBTU). Oil costs range from $6 to $8/10^{9}J (or/MBTU) depending on inflation and Windfall Profits Tax Treatment.

Another way to view the major economic and engineering variables is to rate them according to their degree of variability (i.e. similar to a statistical distribution's standard deviation) and according to their impact upon NPV (i.e. their differential impact). We rated variability as very high "VH" (greater than 100% change above the nominal value possible), high "H" (greater than 50% change), medium "M" (greater than 25% change) and low "L" (greater than 10% change). We rated their differential impact by using an approximation to the absolute value dimensionless first difference, for example:

$$\text{Differential} = \frac{\dfrac{\Delta\ \text{NPV}}{\text{NPV Baseline}}}{\dfrac{\Delta\ \text{Variable}}{\text{Variable Baseline}}}$$

Table 8.17 shows the ranking of variables in terms of a "probable impact index". These indices are the products of the first differences, and range of variability limits. For example, for tax life the first difference value is 7 to 9 and the range of variability fraction is 0.25, so the impact index product is 1.8 to 2.3. The top ranking "probable impact index" variables are credits and TIR, oil price escalation (really a second difference on oil price), discount rate and tax life. If only first differences were considered, solar output would replace discount rate. The effect of the high credits is to reduce the sensitivity to investment and solar output. In a low credit case, it seems likely that these effects would also be highly significant, especially solar investment.

Table 8.16

Economic Performance Of The Preliminary Design System
(Fossil Levelized Energy Cost = $6.62 MBTU Unless Noted Otherwise)

#	Case Title	NPV ($1000)	20 Yr Hybrid System Levelized Energy Cost At 15% Discount $/10^{9}J	($/MBTU)
1.	Baseline	$170	$ 6.14	($ 6.48)
2.	No Cal. Credit	($744)	$ 6.87	($ 7.25)
3.	No T.I.R.	($6,435)	$11.40	($12.03)
4.	Only US Credits	($7,349)	$12.13	($12.80)
5.	11 Yr SOYD Depreciation	$125	$ 6.18	($ 6.52)
6.	7 Yr SOYD Depreciation	$932	$ 5.50 (Fossil=$6.24	($5.80) ($6.58))
7.	1 Yr SOYD Depreciation	$2,598	$ 4.09 (Fossil=$6.16	($4.32) ($6.50))
8.	$40/BBL in 1982	$540	$ 6.75 (Fossil=$7.17	($7.12) ($7.57))
9.	Oil Inflation at 6% above GNP	$717	$ 7.03 (Fossil=$7.60	($7.42) ($8.02))
10.	Oil Inflation at GNP	($221)	$ 5.50 (Fossil=$5.33	($5.80) ($5.62))
11.	Lower WPT (Tier 3)	$531	$ 6.73 (Fossil=$7.16	($7.10) ($7.55))
12.	Investment=+20%	($169)	$ 6.41	($6.76)
13.	Investment=-20%	$633	$ 5.77	($6.09)
14.	Lifetime=25 yrs	$361	$ 6.72 (Fossil=$6.99	($7.09) ($7.38))
15.	Lifetime=15 yrs	($42)	$ 5.47 (Fossil=$5.43	($5.77) ($5.73))
16.	O&M = 2 x Baseline	($1,337)	$ 7.35	($7.75)
17.	O&M = 1/2 x Baseline	$919	$ 5.54	($5.85)
18.	Solar Output =+20%	$615	$ 5.78	($6.10)

#	Case Title	NPV ($1000)	20 Yr Hybrid System Levelized Energy Cost At 15% Discount $/$10^9$J	($/MBTU)
19.	Solar Output = -20%	($270)	$6.49	($6.85)
20.	Discount Rate = 20%	($689)	$6.40 (Fossil=$5.70	($6.75) ($6.01))
21.	Discount Rate = 10%	$1,465	$6.29 (Fossil=$7.15	($6.64) ($7.54))

The Hybrid System Levelized Energy Cost is the equal annualized value of the net present worth (of investments plus annual cash flows) divided by average annual energy delivered. The hybrid investments, cash flows, and energies are for the total system, fossil backup plus solar increment.

Table 8.17 Ranking Of Sensitive Parameters

Parameter	Dimensionless First Difference	X	Likely Range Of Variability: (Value (Code))		=	Probable Impact Index	Relative Rank
1. Credits and TIR	69		> 1.0	(VH)		69	1
2. Tax Life (SOYD) (1)	18		> 0.50	(H)		8.9	4
3. Oil Price (1982)	10		> 0.25	(M)		2.4	8
4. Oil Price Change Rate (vs. 1.10)	118		> 0.10	(L)		11.8	2
5. Investment	10		> 0.25			1.8	6
6. O&M (%) (2)	9		> 1.0	(VH)		8.8	5
7. Economic Life	4		> 0.25	(M)		1.1	9
8. Solar Output	13		> 0.25	(M)		3.3	6
9. Discount Rate (3)	9		> 1.00	(VH)		9.2	3

Notes:

(1) If the proposed "10-5-3" depreciation rules were enacted, the likely range of variability would be 6/11 0.5.

(2) O&M variability is high since little field experience

(3) Investment risk premiums of up to 15% (absolute) above our assumed 15% baseline are possible for new technologies.

8.5.2.4 Preheat Only System Economics and Sensitivities

The use of solar parabolic troughs in a preheat only configuration has also been examined. The results indicate that preheat only systems have a performance advantage over troughs used for making steam and boiler preheat. Excluding escalation, contingency and owners engineering fees; the \$1980 capital cost (based on Exxon Engineering Estimates, Table 6.6) and other data are assumed as follows: (8-82)

- o Area = 9,636 m^2 (103,680 sq. ft.)
- o Capital Cost = \$6,404,000 (\$664.6/m^2 (\$61.77/ft^2) (\$1980))
- o Annual Energy = 10,207 $\frac{MWh}{YR}$ (34.84 x 10^9 BTU/YR)
- o Operating Costs for Solar = \$79,439/Year (\$1980)
- o Solar Electric Costs = \$2,617/Year (\$1980)
- o All other inputs are the same as baseline.

Table 8.18 shows the results of calculation for solar preheat only versus the fossil system. (Its capital costs are in escalated \$1981 and its operating costs include escalation to 1982 and 7% overhead added to the above estimates). Table 8.19 shows the sensitivity of the preheat-only system to changes in O&M, credits, (TIR), and oil inflator. The preheat only system offers a clear cost advantage over the baseline steam system. Its per-unit-area capital costs are 101% of the baseline flash separator/preheat with storage concept, its per-unit-area operating costs are 76% of baseline, and its per-unit-area energy output is 132% of baseline. Its NPV = \$655K versus NPV = \$170K for the baseline.

8.5.3 ANALYZE TAX CREDITS AND ACCELERATED DEPRECIATION

The preceding sections' discussions and calculations have shown the relative effectiveness of both tax credits and accelerated depreciation. This section briefly presents a more detailed look at the sensitivity of energy costs to these factors.

8.5.3.1 Tax Credits and Tertiary Incentive Revenue (TIR)

Figure 8.29 shows the cost per million BTU's of the solar increment of the hybrid system's energy versus a combined level of tax and ERA credits. Through 1985, the WPT legislation keeps a 15% U.S. energy tax credit in place. When added to the already existing investment tax credit of 10%, one sees a tax credit floor at 25%. When the credits plus TIR reach 68%, one breaks even with the cost of fossil energy. Thus, a credit of 43% would be required to be added

TABLE 8.18

ECONOMIC COMPARISON OF FOSSIL AND PREHEAT ONLY SOLAR HYBRID SYSTEMS

****

STEORE CASE # 2 RESERVOIR MODE =NREV

VARIABLE PARAMETER SUMMARY

OIL PRICE /BBL=$	32.67	OIL INFLATOR=	1.100
CAPITAL COST %=	15.00	ASSET TAX LIFE=	11.000
HYBRID EFFICIENCY	82.00	MBTU /BBL =	5.930
ASSET REAL LIFE=	20.00	BACKUP MBTU/YR=	169,984.000
SOLAR MBTU/YR=	34,836.50	BASE SRVC FCTR %=	95.000
SOLAR O&M % OF INV	1.46	ELECT PWR SOLAR =$	3,500.000
FOSSIL SYS COST=$	973,500.00	START YEAR:1982+=	0.000
BACKUP SYS COST=$	973,500.00	SOLAR ARRAY SQ FT	103,680.000
SOLAR COST/SQ FT =	67.94	FRACTION ITC + TIR	0.694

***

SYSTEM PRICE= + $8,017,519.

ANNUAL CASH FLOWS OVER THE ASSET LIFE

YEAR	BASE CASE	HYBRID CASE
1981	- $876,150.	- $3,031,620.
1982	- $460,946.	+ $186,159.
1983	- $519,241.	+ $47,545.
1984	- $577,428.	- $60,053.
1985	- $640,096.	- $171,709.
1986	- $707,650.	- $287,783.
1987	- $780,533.	- $408,667.
1988	- $859,229.	- $534,792.
1989	- $944,266.	- $666,625.
1990	-$1,036,222.	- $804,677.
1991	-$1,758,237.	- $1,458,117.
1992	-$1,936,829.	- $1,668,216.
1993	-$2,132,102.	- $1,892,645.
1994	-$2,338,327.	- $2,072,135.
1995	-$2,564,665.	- $2,268,868.
1996	-$2,813,091.	- $2,484,518.
1997	-$3,085,772.	- $2,720,922.

***

YEAR	BASE CASE	HYBRID CASE
1998	-$3,385,093.	- $2,980,097.
1999	-$3,713,669.	- $3,264,255.
2000	-$4,074,378.	- $3,575,827.
2001	-$4,470,378.	- $3,917,483.

NPV(BASE)	NPV(HYBRID)
- $7,872,245.	- $7,296,515.

NPV (NET) = + $575,730.

BASE CASE ANNUALIZED COST = $ 6.62 / MBTU $6.27/$10^9$J

HYBRID CASE ANNUALIZED COST = $ 6.13 / MBTU $5.81/$10^9$J

Table 8.19 Preheat Only Case Economics

Case	15% Discount NPV ($1000)	20 Year Levelized Costs Fossil $/10^9J	($/MBTU)	Hybrid $/10^9J	($/MBTU)
Baseline Flash Separator/ Preheat Plus Storage Case	$170	$6.27	($6.62)	$6.14	($6.48)
Preheat Only Case	$656	$6.16	($6.50)	$5.81	($6.13)
Preheat Sensitivities:					
Oil Inflator = 1.132	$904	$7.71	($8.13)	$6.99	($7.37)
No TIR	($2,172)	$6.27	($6.62)	$8.00	($8.44)
2 x O&M	$ 93	$6.27	($6.62)	$6.20	($6.54)
20% Discount Rate	$ 62	$5.70	($6.01)	$5.63	($5.94)

to US credits of 25% to give a 15% discounted cash flow breakeven, once the E.R.A. incentive terminates (September 30, 1981).

8.5.3.2 Shortened Depreciation Tax Lives

Figure 8.30, shows the levelized energy cost of the solar energy delivered by the solar increment of the flash boiler/preheat plus storage system versus the tax life. An all sum-of-years-digits (SOYD) method is used to simplify the calculations. In one case, we assume TIR and 30.4% California and U.S. Credits and in the other we do not assume TIR. At 11 years, the usual oil field equipment tax life, we have our solar increment cost of $\$5.75/10^9$J ($6.07/MBTU). If the tax life is 7 years, the solar cost is $\$2.21/10^9$J ($2.33/MBTU).

If we remove the benefits of TIR and keep US and California credits at 30.4%, the tax life effect at 11, 7, 1 years is as follows:

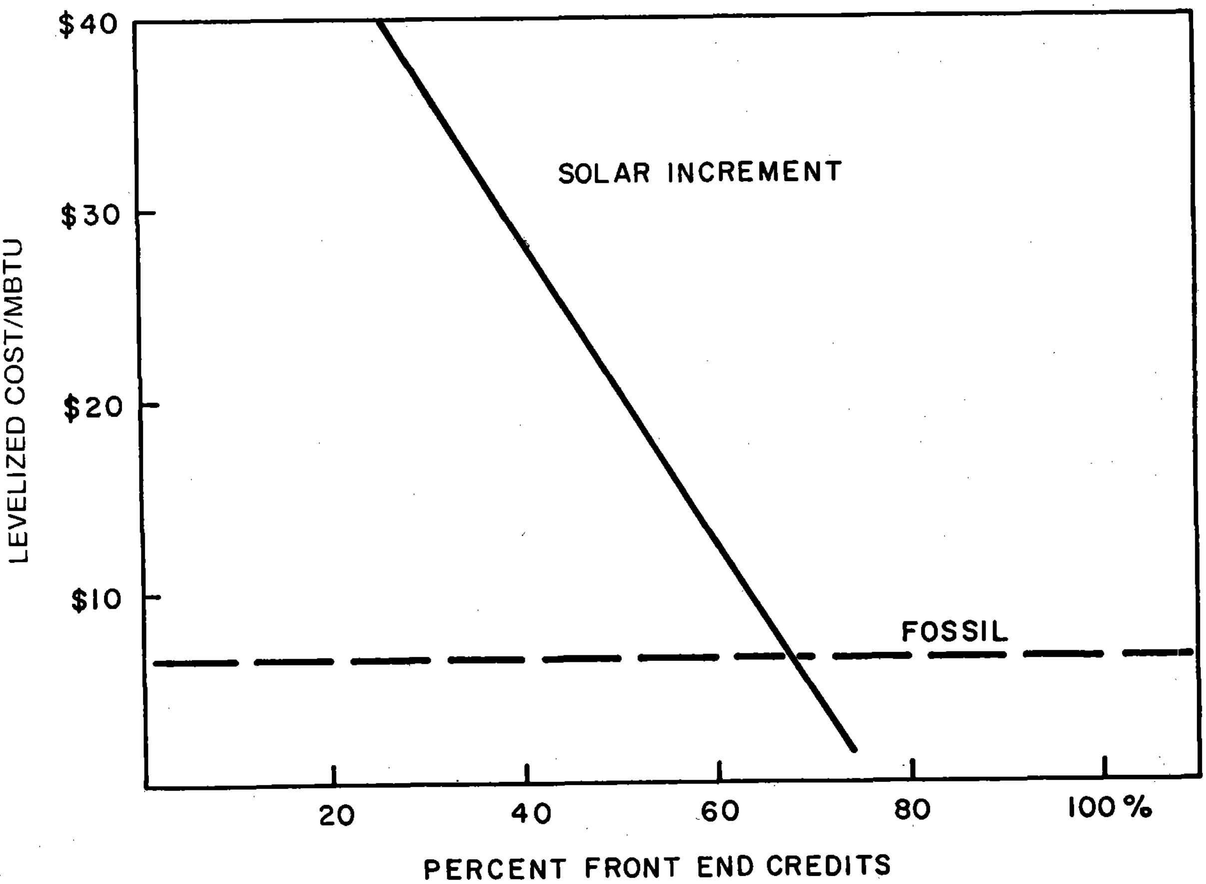
20 Year, 15% Discount Solar Increment's
Levelized Energy Cost $\$/10^9$J ($/MBTU):

Life (years)	(With TIR)		(Without TIR)	
11 (SOYD)	$5.75	($6.07)	$34.44	($36.34)
7 (SOYD)	$2.21	($2.33)	$30.96	($32.67)
1	-$5.68	(-$5.99)	$23.58	($24.88)

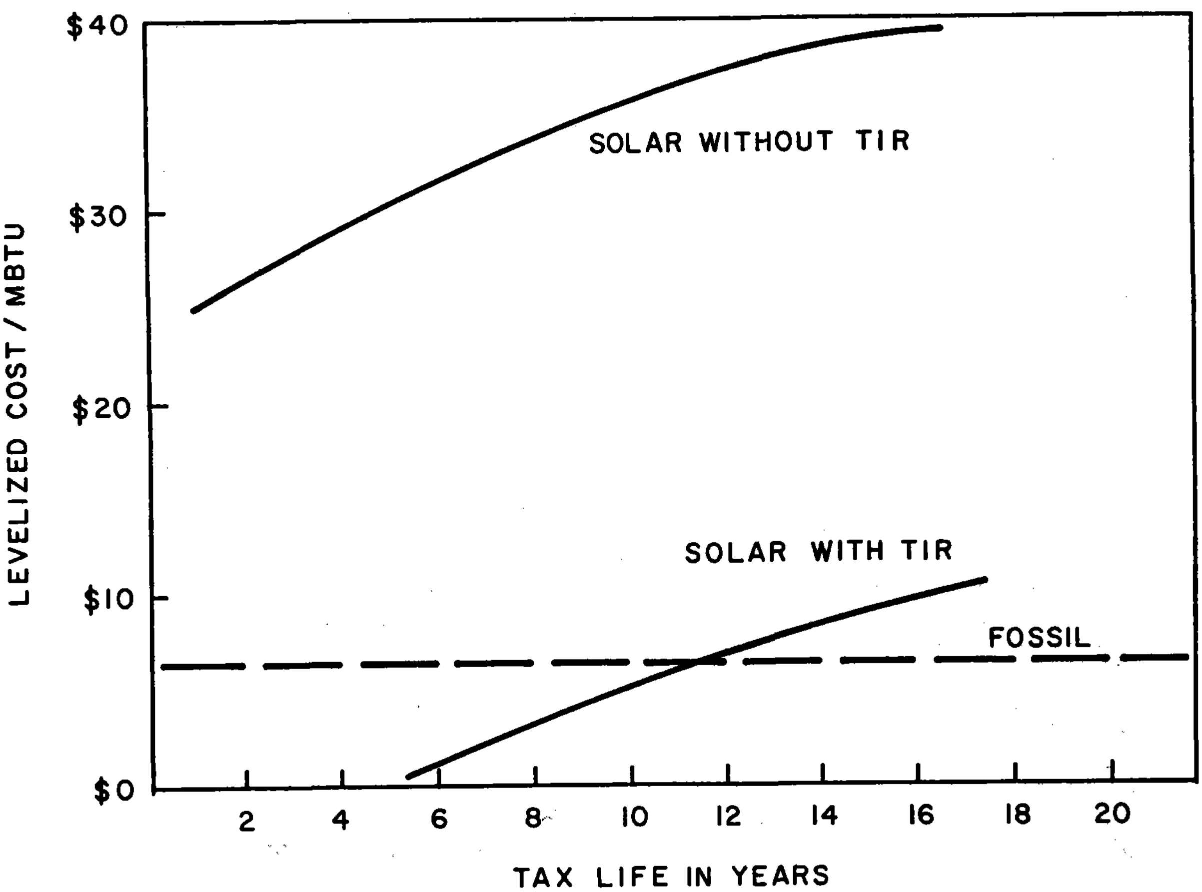
This table clearly shows that accelerated depreciation, even if legislated down to a 1 year tax life, cannot provide a sufficient incentive to make solar competitive with $\$6.27/10^9$J ($6.62/MBTU) fossil generated steam, once the TIR incentive ends.

8.5.3.3 Comparison of DOE Grants vs Tax Credits

Besides depreciation deductions and tax credits, a STEOR project could use a direct DOE grant (line-item budgetary funds) to enhance its attractiveness. These two incentive options (grants and credits) may or may not appear to be equivalent. The comparison depends upon the rules for addivity and accounting treatment. Solar specific tax credits or TIR, are additive to depreciation and base investment tax credits. This is because TIR and solar credits do not change book values used for calculating baseline tax credits and depreciation. If a DOE grant is accepted, however, the project's book value basis is reduced dollar-for-dollar by the grant. The baseline credits and depreciation tax deductions are then calculated on this reduced (net of grant) book value basis.



(Note: $0.95/10^9J = $1/MBTU)
SOLAR INCREMENTAL ENERGY COST VS. CREDITS
FIGURE 8.29



(Note: $0.95/10⁹J = $1/MBTU)

SOLAR INCREMENTAL ENERGY COST VS. TAX LIFE

FIGURE 8.30

An observable consequence of this fact about grants is that given a baseline case where solar is not quite economic (see Table 8.20), a grant several times in excess of the negative net present value on the proposed project is required to close the gap. This difference in increments suggests that "credits are more effective than grants". The actual relationship is situational and depends upon:

1. Grant valuation formulae (discount rate).
2. Perspective: private firm, DOE, U.S. Government, society

Consider the following illustration:

Investment for Solar

$3.489 million

Baseline Tax Credits (Prior to Recent Changes)

Investment	10%	
Energy	10%	
Cal. Solar	8.1%	(after tax effects, before WPT passage)
	28.1%	

Depreciation

11 year term
2 yr. DDB, 9 yr. S.O.Y.D.
51% Tax Rate (See Section 8.5.2.2.3)

Credits and Depreciation

Basis are private firm's investment (i.e., price minus grant), but depreciation is additive to the grants.

Baseline Results

NPV (solar investment at 15% discount)=($0.489) million

CASES

1. Baseline, described above
2. Credit to provide $0 NPV is $\frac{\$0.489}{\$3.489} = 14\%$

3. Grant to provide $0 NPV is $1,128 Million (from STS economics algorithm)

Table 8.20 shows the comparison of the three cases. As can be seen from Cases 2 & 3, the total treasury outlay--either cash paid or taxes foregone--is the same (allowing for rounding errors)for either grant or credits. (The E.R.A. tertiary incentive revenue, 10 CFR 212.78, will result in a lower cost to the treasury than a grant, since the incentive is provided directly by the consumer of oil products).

The equivalence of grants and credits is true, only if all the participants use the same discount rate which is fixed with certainty. If no discounts are applied by the treasury, then the example shows that "Added Credits" are more costly to government (ignoring administrative burdens) due to the reductions in taxes paid because of depreciation as follows:

Combined Governmental Outlay

CASE	INITIAL OUTLAY	DECPRECIATION INDUCED CASH FLOWS		UNDISCOUNTED LIFETIME SUM
YEAR	0	1	2	
Baseline	$0.980	0.324	0.265	$2.759
Added Credits	$1.469	0.234	0.265	$3.248
Grants	$1.792	0.219	0.179	$2.99

If one suspects that the Government uses a lower discount rate than 15% and the firm uses a higher rate, then credits look less attractive than grants. This is because the higher depreciation deduction with credits has a lower perceived value to the firm by virtue of being discounted heavily, and the losses to the treasury (from larger depreciation deductions with the added credit) have a higher perceived value by the government, since they are not discounted heavily. Credits, however, can still be more attractive because of situational factors. They usually have lower relative administrative costs to both government and user since tax system is used, and they can permit more design flexibility.

Table 8.20

MILLIONS OF DOLLARS

	BASELINE 1	ADDED CREDIT 2	DIRECT GRANT 3
Price	\$3.489	\$3.489	\$3.489
Grant	0.000	0.000	1.129
Book Value	3.489	3.489	2.361
28.1% Credit	0.980	0.980	0.663
14% Credit Added	0.000	0.489	0.0
Depreciation After Discount at 15%	1.033	1.033	0.699
Total Governmental Funds (Expenses or lost revenues) (1)	2.013	2.502	2.491
NPV (at 15%)	(0.489)	0	0
Capital to be Recouped from Operations (1),(2)	1.476	0.987	0.998

Note:
1. Difference in column 2 and 3 is due to rounding.
2. Columns do not add due to rounding.
3. Before Windfall Profits Tax Act effects.

8.5.4 FEASIBILITY AND DESIRABILITY OF LEVERAGED LEASING

8.5.4.0 Introduction

Solar energy projects are primarily capital-cost intensive undertakings, while oil-fired energy projects are primarily fuel-cost intensive. To become economically acceptable to follow-on buyers, future STEOR systems will have to meet two criteria:

1. Be affordable in terms of front-end capital requirements.

2. Provide a return-on-capital comparable to other energy projects--or provide purchased energy at prices lower than fossil-fired systems.

The use of a project financing technique, specifically leveraged leasing, has been suggested as a means to meet these criteria. In this section we summarize our review into the desirability and feasibility for leveraged leasing of future STEOR projects.

8.5.4.1 Definition of Terms

Peter Nevitt suggests the following definition of project financing:

> A financing of a particular economic unit in which a lender is satisfied to look initially to the cash flows and earnings of that economic unit as the source of funds from which a loan will be repaid and to the assets of the economic unit as collateral for the loan (8-83).

The concept is that the economic attributes of the project alone (its cash flows and its assets) form the initial basis for the financing arrangement. Considerably less reliance is placed upon the financial attributes of the sponsoring organizations. This represents a departure from conventional financing techniques where the sponsoring firm itself is the major focus of concern. There are many examples of specific projects where project financing has been employed including: coal mines, electrical generating plants, terminal facilities, pipelines, etc.

The term, leveraged leasing, describes a special class of project financing arrangements, in which both loans and leases are used within a multi-party financial structure. The typical leveraged-lease arrangement involves: a user--lessee, an owner--lessor, and a lender who writes a mortgage to the lessor for the project. Specific legal covenants which bind the parties and appropriate trustees to handle the ownership and indenture (loan) relationships complete the structure.

Leveraged leasing methods have been used to increase sales of capital intensive products such as merchant ships, surface transport vehicles and data processing equipment. An industry of general purpose "leasing companies" has emerged to service these markets as lessors. The lessees have benefited from the availability of needed capital equipment without the need for extending their debt structures. In the case of data processing equipment, they have also been attracted by service features and obsolesence guarantees implicit in leasing, but not present in ownership.

Lenders have been found among commercial banks, pension funds, insurance companies and other institutions. These intermediaries typically provide a mortgage to the lessor on the equipment. (See references 8-84 to 8-106 for a more detailed discussion of leveraged leasing).

8.5.4.2 Evaluation Criteria

We selected two criteria to evaluate this financing option; feasibility and desirability. By feasibility, we meant whether a STEOR project (as a leasing opportunity) would have the essential economic characteristics (risks and returns) necessary to satisfy lessors, lessees, and lenders. By desirability, we meant whether a leverage leased STEOR project would effectively overcome the limits on front-end capital formation and the required cost-of-capital hurdle present in either a conventionally mortgaged or 100% equity purchase by a potential STEOR user.

8.5.4.3 Findings

STEOR either as a technology, or as a business opportunity has no past history. Significant uncertainty exists about actual system costs, operating performance and economic lifetimes. STEOR's impact (assuming diurnally steaming systems) upon reservoir performance is unknown. The cost of competitive fossil fuel based alternatives and the ultimate EOR product prices are likewise subject to large variabilities. All these questions become significant concerns in the eyes of any lender. At least one source states flatly that project financing requires that "The project is not a new technology" (8-107). Absent some years of hard, verifiable operating data to allow a systematic risk assessment, an unguaranteed (and non-recourse) loan from a prudent lender is today infeasible. Absent such a lender, leveraged leasing is by definition also infeasible.

We may, however, for the purposes of discussion assume that an allowable level of risk could be established for STEOR at some future point in time. If a leveraged lease were possible and if the benefits of a market rate of debt and a highly leveraged lessor could be provided, would the results significantly improve the attractiveness of STEOR? Our review suggests that the improvement in attractiveness of STEOR will be situational to the user. It will benefit TEOR producers who:

1. Could not use the STEOR tax benefits fully, if they owned the system.
2. Believe there is an advantage in off balance sheet financing.
3. Believe the arrangement will be non-recourse to them.
4. Can obtain a lower cost/unit energy through lease payments.
5. Lack front-end capital, but have a worthwhile project for others to fund.

We can state, however, that first the solar project lease will have to be economically profitable to the lessor as a business venture. Thus, a STEOR project whose after-tax rate of return was below that of lessor's debt would not be attractive at any loan fraction.

We first assumed that the world will return again to pre-1979 economic conditions of 7% inflation, 9% corporate bonds and 15% to 20% equity (See Appendix I for rates). We excluded any user industry behavior which may assign special hurdle rate penalties to energy conserving projects. We found that the maximum benefit in terms of cost of capital reduction would be to increase the allowable after-tax discounted payout (1/capital recovery factor) from 6.3 years (if entirely funded from 15% equity) to 13 years (if entirely funded from 9% debt). Since it is unlikely that low equity returns will be permitted for highly leveraged leasing companies, the real leveraged payout increase would have to be less, for example to 10.1 years, (if the lessor had 80% leverage, 9% debt and 20% equity) (8-108). If the project was especially risky and the debt rate climbed to 14% (Prime Rate + 5%), then the payout would only increase from 6.3 years to 9.1 years. In any case a benefit of up to 4 years extension in allowable payout seems possible.

If our example is restated in terms of return-on-capital, the STEOR project lease would need to provide the lessor with an effective after-tax return of between 7.6% and 9.6%. Absent, today's ERA Teritary Incentive, it appears that current line focus STEOR technology is incapable of meeting this low return target. If solar cost effectiveness increases as suggested by section 8.2's cost/performance projections, Solar EOR could become a viable investment to lessors. Even then, however, it would still need to be compared to other equally risky leasing opportunities before being accepted.

8.5.4.4 Structure

As noted previously there are several participants in a project financed through leveraged leasing: a lessee, a long-term lender, a lessor with an equity participant (sponsor), and trustees.

The obligations of these participants can be structured in a variety of ways to meet the parties' objectives, to fulfil IRS requirements for a true lease and to agree with the Financial Accounting Standards Board Opinion (FASB No. 13) on financial reporting of leasing arrangements. To meet IRS rules, a true lease should have certain necessary characteristics. The lease contract must assure that the lease receipts exceed total loan payments by a reasonable amount, and that the leased asset must have at least 20% of its estimated useful life remaining at the end of the lease term. Moreover, the fair market value of the leased property at the end of the lease has to be 20% of the original cost. The terms may only permit the lessee to purchase the asset at its fair market value at the end of the lease (no discounts) (8-109). (The IRS has established detailed guidelines in this area for the purposes of issuing rulings). Given the organizational, regulatory and legal complexities and costs of leasing, projects involving less than a million dollars are usually not considered for project financing.

The potential lessors, or equity participants, own the project equipment and utilize the tax benefits accruing to such ownership. The ownership can be organized through single or multiple equity participants (joint ventures, partnerships), a captive finance company, or third party leasing companies (banks, leasing companies, equipment manufacturers, and unconsolidated subsidiaries). It would appear to be possible for an oil field owner to participate as the lessor through, for example, an unconsolidated subsidiary and thus enjoy the advantages of a separate business entity. This lessor entity will then lease steam--or the equipment to produce steam--to the lessee. In most cases, an Owner Trust agreement is entered into by the equity participants. This helps ensure that the owners maintain appropriate tax relationships and complies with the wishes of the lender.

The lenders (banks, insurance companies, pension funds, etc.) supply the debt capital to the lessor to purchase the goods and services. The Owner Trustee enters into an agreement with a second, Indenture Trustee, who represents the lenders. The monies for both the initial acquisition and/or construction of the goods to be leased and the resulting rental payments flow through these trustees. The indenture trustee uses the lessee's rental payments to service the debt, deduct fees, and distribute funds to the lessor's equity participants.

The cash flows during purchase/construction of the project to be leased appears in Figure 8.31. The granting of the loan (up to 75% of the cost of the asset) is often made contingent upon the signing of a take-or-pay contract between the lessor and lessee. In the take-or-pay contract the lessee has to pay the amount agreed upon to the indenture trustee regardless of whether or not the good or service is supplied by the lessor. The amount of these lease contracts should be enough to comfortably service debt and to pay all expected operating expenses. If these are properly estimated, the lender is protected. In general the stronger the financial status of the lessee, the stronger the non-recourse status of the loan is to the lessor's equity participants. The timeliness of purchase/ construction is very important to the parties, and agreements are based upon strict adherence to timetables, with strong contingency plans and penalties. Once the project is operational, the money flow is as shown in Figure 8.31, with the lenders serviced first.

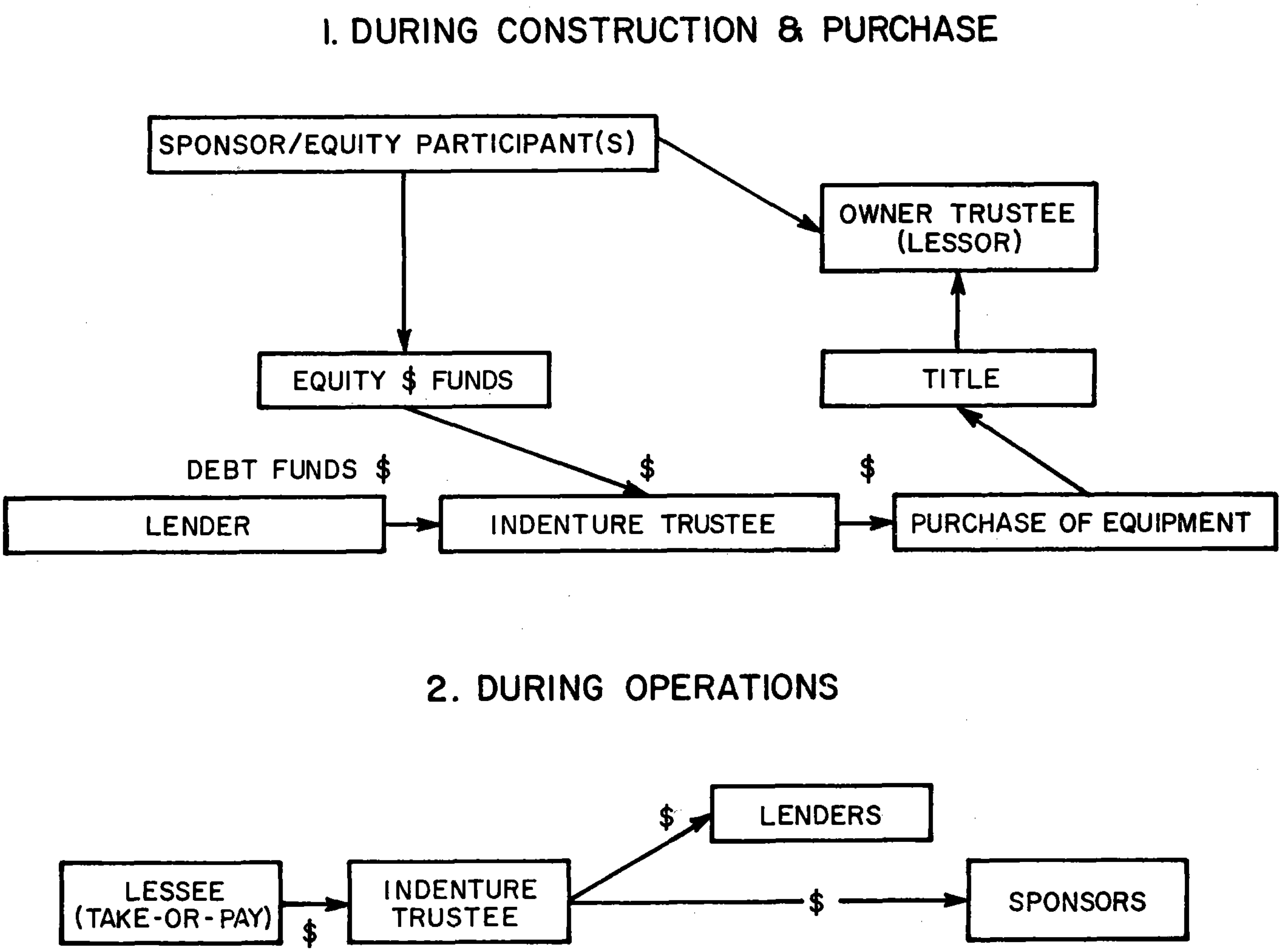
The preceding description is a basic example of one of the many ways to organize a project utilizing leveraged leasing. Another variation is the sale and lease back of the equipment. There, the potential lessee would first buy (construct) the equipment, and then would sell it to the lessor. The lessor would leverage his purchase and lease back services or equipment to the lessee. This approach decreases the advantages of leveraged leasing to the lessee, since his funds have to be committed up front to the project. Under some situations, the lessor's tax incentives could be reduced and so the lessee's rentals would increase. A positive attribute of sale and leaseback is the greater control that the potential lessee has at the outset of the project (i.e. during design and construction).

8.5.4.5 Benefits of Leveraged Leasing

The principal advantage for the project sponsor, who is often an equity participant in the leasing company, is the wide variety of financial structures which may be selected to coincide with both practical and theoretical objectives of the firm.

One objective is "off-balance sheet" financing. This term applies where a capital intensive project can be financed without an increase in the debt account which appears on the sponsor's published balance sheet (and where the asset does not appear either). If not otherwise included in financial ratios, having debts "off-balance sheet" does not hinder the sponsor's ability to raise further capital. The "off-balance sheet" nature of a project (if the sponsor company controls less than 50% of the leasing company) may often be considered an indeterminate plus by financial analysts. However, more sophiscated analysts will take such "off-balance sheet" actions into account when evaluating a firm. This is possible because "off-balance sheet" financings are usually required to be included in notes to a firm's financial statements.

A second objective is optimal use of the tax and other incentives available to capital intensive projects. Such incentives include: various investment and energy tax credits, Tertiary Incentive Revenue, and accelerated depreciation schedules. The incentives have little value to the various parties involved unless they are applied to entities who have enough other income to offset with depreciation deductions (or who have tertiary incentive revenue oil). When applied to lessor firms who can reduce taxes, etc., their



LEVERAGED LEASING STRUCTURES
FIGURE 8.31

benefits can be passed through in lower rental payments for the lessee. If there were no other income to offset, then these major tax incentives would disappear. In any case, good lease agreements are carefully constructed to ensure proper classification by the IRS as concerns tax benefits.

A third objective is to avert risk to the sponsor firm by means of the nonrecourse debt of the lessor. This is a major factor in project financing. In project financing the lender has recourse only to the purchased equipment and not to its owner or user. This level of recourse is sufficient for many projects, especially where the equipment is readily marketable.

The lessee's goal is to minimize the cost of a good and/or service to him through the lessor's utilization of tax incentives (and skill advantages) not available to the lessee. Other lessee advantages from leverage leasing may include: minimized front-end costs; higher book earnings in the first years (when the largest expenses of depreciation and interest are taken by the lessor); fixed rental payments for solar which can be planned for versus uncertain, escalating future fuel prices; preservation of mineral depletion allowances and non-dilution of ownership.

8.5.4.6 Risks of Leveraged Leasing

In selecting a leveraged lease arrangement each party will carefully compare a project's specific risks against those of the aforementioned benefits which may apply. While the lessor and lessee gain significant "upside" benefits for their risks, the lender does not. Hence, the prudent lender is primarily concerned with avoidance of risks which might cause the lessors to default on their loans.

The key for any project to be financed (securing debt) on its own merits is its ability to demonstrate stability. If stability and its accompanying characteristics are not present, the outlook for leveraging a lease, or other project financing is doubtful. The conditions studied by lenders to assure stability are a strong backing evidenced by the financial capability of the sponsor company, expertise of design and construction contractors involved, financial capability of meeting overruns, proven management, sponsor equity investment, sponsor expertise in project, and strong offsite supply and transportation contracts and/or arrangements. These conditions can usually be met when a project/technology is proven. As mentioned previously, unproven technologies with major uncertainties in capital and operating costs, revenues, timing, residual values, technical and organizational management, are unlikely to be viewed favorably by the prospective lender.

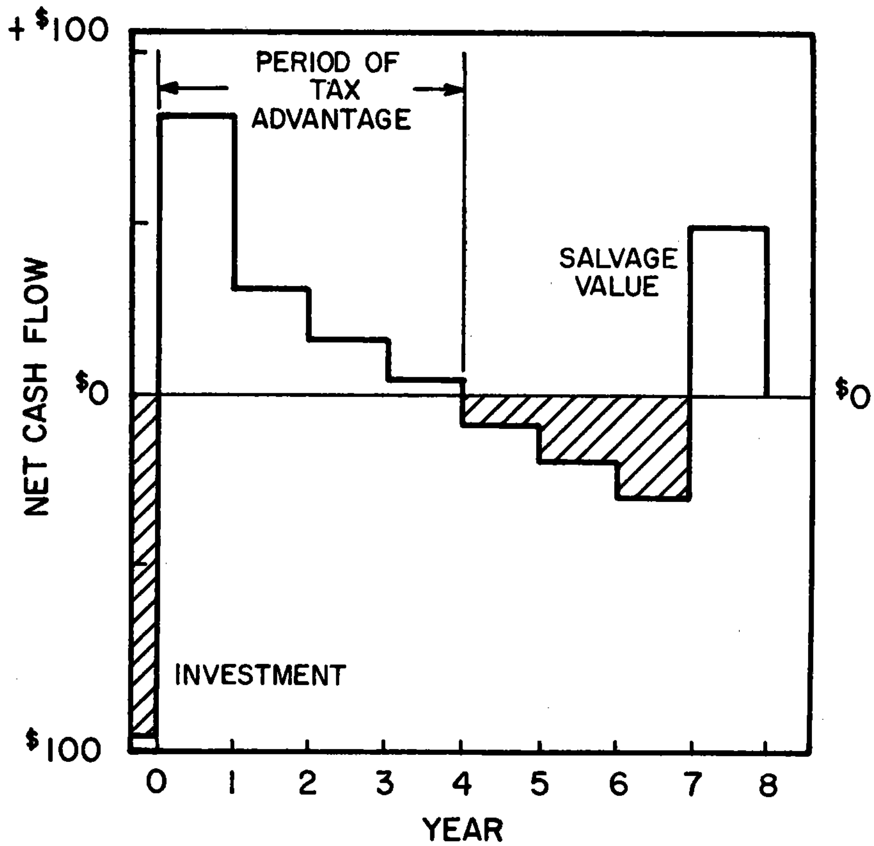
These uncertainties make new technology projects more prone to completion delays, and cost (both capital and operating) overruns or technical failures. These problems are commonly described as completion and operation risks. In STEOR, there are also reservoir risks to consider. For example, the field life could be substantially shorter than expected or new environmental regulations could shut-in boilers thus negating part or all of a STEOR hybrid system's output.

For a successful project, one or more of the parties other than the lender will be expected to cover the completion and operation risks. That party is often assumed to be the lessor. For example, a construction company may guarantee certain operational characteristics which allow the lessor to refuse to accept a project until it works to his specification. This guarantee, however, still does not solve his problems with the lessee and the lender arising from the delay. Once operating, the system performance could degrade on an accelerated basis. If rentals are tied to performance, the lessor will be in cash losing position, tied to a fixed mortgage and with no hope of increased revenue. Other operating concerns would include "Acts of God", etc., such as violent wind storms, coolant losses, earthquakes, plane crashes, fires, flood, civil disturbances, which could harm the STEOR project (but many of these occurrences are equally threatening to any project). The lessor could assume an insurance responsibility to the lender for these catastrophic occurrences, but the insurance will do little to help the lessee, should they occur.

Reservoir risks would be assumed by the lessee. Unfortunately, the assumption of such risk without strong financial resources on the lessee's part does little for the lessor and lender if they are left with ten million dollars of capital equipment physically located at a depleted reservoir. The same potential for reservoior risk occurs with a boiler facility, but the boiler investment is much less than solar and the units would be quasi-portable. Thus, even if solar technology becomes well developed and accepted, leveraged leasing might still be unacceptable to lenders and lessors at particular 'risky' reservoirs.

8.5.4.7 Leasing Cash Flows

The normal behavior of the lessors' cash flows in a leverage lease indicates another problem for STEOR; the negative impact of expected declining future constant dollar costs for solar equipment upon the lessors salvage value cash flow. After the initial outflow of cash for the purchase, the cash flow (with initial tax credits and high depreciation, and interest deductions against other income) is positive as long as there are profits with which these write-offs can be linked. However, in typical leases as



LESSOR CASH FLOWS
OVER THE LIFE OF A
TYPICAL LEASE

FIGURE 8.32

depreciation deductions and interest payments decrease with time, a negative cash flow results for the lessor and continues until the lease expires at which time the residual value of the equipment is received. The estimation of the residual value is important in the proper calculation of rental payments made by the lessee and reported under FAS 13 guidelines in the lessor's annual report (8-110). Depending upon the length of the lease, residual value can substantially affect the return. With high dismantling costs and decreasing real replacement costs expected, the difficulty of estimating the residual value of the STEOR equipment makes any lease analysis less certain. Figure 8.32 illustrates the cash flow of a normal leveraged leasing investment from the lessor's point of view.

In year 0 of this hypothetical 8-year lease, the cash flow is negative because of the initial outlay. Thereafter it is positive for four years. After that time the low depreciation deductions and interest charges and resulting smaller decreases in taxes cannot offset cash outflows. The cash flow again becomes positive upon disposal of the asset at the end of the lease. The return to the lessor is calculated by allocating income to years in which investment is positive using a calculated rate of return (see Reference 8-91).

8.5.5 FEASIBILITY AND DESIRABILITY OF TAX EXEMPT POLLUTION CONTROL BONDS

8.5.5.0 Introduction

As was noted in Section 8.5.4, STEOR projects are highly capital intensive. Thus, their economic attractiveness depends upon a potential owner's ability to overcome hurdles on front-end capital formation and rates-of-return. One option for meeting this requirement is to use debt capital to leverage the project's financing. If the cost of this debt is less than the firm's cost of equity capital, and if the equity cost is unchanged as the proportion of debt in the capital structure increases, then the economic attractiveness of the project will be improved.

Bonds are one type of mid-to-long term debt instrument which has been used to leverage a firm's capital structure. In recent years (up to 1979), bond (8-111) coupon rates were on the order of 8% to 10% for quality industrial issues. Even lower coupon rates were available to firms who could qualify to issue Tax Exempt Bonds. The Internal Revenue Code provided that interest income from certain bonds, whose proceeds were employed to fund "socially worthy" projects (e.g. hospitals, roads, pollution control, etc.), could be excluded from a "person's" U.S. taxable income. The advantage of this tax saving to investors was then passed along by them to the debtor in the form of lower coupon interest rates, often 5 to 7% (up to 1979).

STEOR projects can be expected to reduce the relative amount of oil burned in EOR operations. Section 8.4 states that this reduction in fuel burned would offer a corresponding reduction in the absolute amount of pollutants emitted from the EOR boilers. In this sense, solar might be considered to be a "pollution control" measure. As such a measure, solar could be expected to be eligible for partial or total funding using state government authorized tax exempt pollution control revenue bonds. The remainder of this section examines the hypothesis that STEOR can benefit from financing with pollution control bonds.

8.5.5.1 Definition of Terms

The term "Tax Exempt Bond" is properly defined for a particular situation according to the rules of the Internal Revenue Code and various revenue rulings by the Internal Revenue Service. The Internal Revenue Code of 1954, Section 1.103(c)(4) allows a tax exemption for interest received on, "... any obligation which is issued as part of an issue substantially all of the proceeds of which are to be used to provide... (F) Air or water pollution control facilities". In the Code, Section 1.103-8(g) (2)(ii), the property (equipment) is defined as a pollution control facility if it"... is property to be used, in whole or in part, to abate or control water or atmospheric pollution by removing, altering, disposing, or storing pollutants, contaminants, wastes or heat". Since retrofitted solar equipment is designed to produce steam, besides reducing existing pollution levels, it appears that Section 1.103-8(g)(2)(iv) applies: "In the case of property to be placed in service for the purpose of controlling pollution and for a significant purpose other than controlling pollution, only the incremental cost of such facility satisfies the test of this subdivision. The 'incremental cost' of property is the excess of its total cost over that portion of its cost expended for a purpose other than the control of pollution". Furthermore, Section 1.103-8(g)(2)(v) further states that: "An expenditure has a significant purpose other than the control of pollution if it results in an increase in production or capacity, or in a material extension of the useful life of a manufacturing or production facility or a part thereof". Since, the STEOR project will increase either production or field life or some share of both, it would appear to "have a significant purpose other than the control of pollution..." per section (v).

Finally, these bonds are assumed to be "revenue" bonds, not "general obligation" bonds. We assumed that the proceeds of the debt would be exclusively paid off by the funds generated by the STEOR project (i.e. revenue bonds) and not by funds from state or local tax revenues (i.e. general obligations). We also assumed that no governmental guarantees for principal or interest would be available. This was assumed because the presumed objecive of selecting financing methods such as tax exempt bonds is to reduce or eliminate any requirements for direct government budgetary assistance (grants, loans or guarantees) to STEOR.

8.5.5.2 Evaluation Criteria

As in section 8.5.4 we have applied the criteria of feasibility and desirability to this financing option. In this instance, feasibility is tied to:

(1) Eligibility of the STEOR investment under IRS Rules

(2) Availability of currently uncommitted bonding authority at the state level

(3) Availability of investors for these tax exempt revenue bonds.

Desirability is again measured in terms of:

(1) Reduction in front-end capital requirements

(2) Lowered rate-of-return requirement.

8.5.5.3 Findings

The feasibility of using existing authorized California Air Pollution Control Tax Exempt Bonds to finance STEOR projects is doubtful. A laymen's review of the Internal Revenue Code definitions and several related revenue rulings strongly suggests that little, if any, of the STEOR project costs would qualify.

First, STEOR systems will give the user an increased (non-pollution) benefit in lowering the oil burned, i.e. they will increase his oil field production (all other things being constant).

Second, while one might infer that STEOR projects remove pollutants from the EOR "process stream" in its broadest sense by displacing fuel, convincing the IRS that this "pollution abatement" is another matter. Recent IRS revenue rulings suggest that a very strict line is being taken in defining what is meant by "abatement", for example:

- o Rev. Rul. 75-167, 1975-1 CB 40.

  A smokestack for a steam electric generator of a public utility to be constructed to disperse pollutants at a high altitude, although certified by a state pollution control authority as being in furtherance of the purpose of abating or controlling pollutants, will not qualify as an air pollution control facility.

- o Rev. Rul. 75-404, 1975-2 CB 39.

  A new, advanced design acid plant meeting federal and state ambient air standards, but having no specific equipment to remove, alter, dispose of, or store pollutants, contaminants, wastes, or heat, that is constructed to replace existing air polluting plants will not qualify as an air pollution control facility.

- o Rev. Rul. 75-334, 1975-2 CB 37, revoking Rev. Rul. 73-433, 1973-2 CB 21

  A new recovery boiler that was used to recover valuable chemicals from residue, but which did not abate or control pollution, and that was installed in a paper mill to replace operating capacity lost due to a reduction of operating levels of two existing boilers that was made in order to comply with air pollution control requirements did not qualify as an air pollution control facility.

The second ruling appears to be the most damaging to STEOR. STEOR appears to be passive in its effect upon pollutants; it merely displaces energy production capacity which otherwise would generate pollutants. STEOR does not actively separate pollutants out of the process stream and has no "specific equipment" to do so. Even if STEOR were considered eligible, then the definitions regarding the financing of only the "incremental cost" of pollution control would present major difficulties. Since solar contains no components which are strictly cleanup equipment, it is difficult to suggest what portions would constitute the difference in "total costs" (which IRS code Section 1.103.8(g)(2)(iv) says are eligible for funding).

Third, California's existing bonding (FY79) authority was reported as being essentially committed except for $90 million to be used for small businesses set asides (8-112). (Such set asides would most likely be unavailable to major EOR field operations). For small producers, if one assumes a $i million limit per project operator, then only 10,000-20,000 square feet of collectors, an insignificant STEOR operation, could be funded at current (1980) costs). Our investigations did not determine if any FY80 funds had been or would be authorized.

Lastly, the problem of lender risk (discussed previously under leveraged leasing) remains unsolved. STEOR is unproven, Pollution Revenue Bonds are not guaranteed, and their repayments based solely on expected STEOR revenues. No prudent lender would purchase such bonds. Speculative investors might be found to purchase the issue, but they could easily demand rates of return in excess of equity levels, since bonds bought at par value have no upside gain.

If Federal laws and tax codes were to be revised to specifically include all of a solar project's costs as a pollution control investment and if STEOR became an acceptable "credit" (lending) type of risk, then would these bonds improve the economic desirability of STEOR? If one looks to major corporation EOR operators, and if one assumes a middle ground viewpoint about the effect of leverage upon a firm's total capital structure, then the impact of these bonds would appear to be minor.

We assumed for our analysis that the typical large EOR operator's capital structure would have about 40% debt (with average annual cost of 9.7% before tax) and 60% equity (valued at 15.1% after tax) (8-113). Since a single STEOR project would probably be very small (less than 1%) relative to the firm's total assets, its financing would not materially change the overall debt/equity ratio or the firm's financial ratings. Since this would not be a project financing, (i.e. it would be "on balance sheet"), the cost of capital for STEOR should properly be leveraged at the corporate debt equity ratio. However, the cost of debt could reasonably be reduced to account for the benefit of a tax exempt rate, i.e. from 9.7% to 5%. Including 50% taxes and the 40/60 debt to equity ratio, the cost of capital for this project would be reduced from 11.0% to 10.1%. This is a small incentive, but for an already economic project might be worth the administrative effort necessary to save several hundreds of thousands of dollars per year in interest expense.

If the small independent operator's case were considered, the improvement could be more substantial. Increasing leverage with debt could be expected to show a rate-of-return hurdle reduction, however, the implied increase in the financial riskiness of the firm could also be expected to have two counteracting effects. First, the coupon rate on the tax exempt bonds themselves would probably be higher, since the small sponsoring firm would have less financial backing to offer investors than would a major operator. Second, the overall financial riskiness of the EOR operator would increase as his fixed debt obligations grew. An efficient market could be expected to demand a correspondingly greater return on his equity, which would offset his savings on debt costs. In the extreme case, the Modigliani--Miller hypothesis would argue that there would be no improvement in the weighted cost of capital regardless of leverage (8-114).

We have chosen to follow a less extreme position, suggested by other financial authors (8-115). Before leverage, our small firm would be assumed to have a 50/50 debt ratio, 10% debt (lower quality) and 20% equity (riskier firm). If the STEOR project is added and accounts for an increase of about 10 points on the debt ratio (i.e. to 58/42), the tax exempt rate is 7% (pre-1980 basis) and the equity cost grows by 1/10 to 22%, then the cost of capital (firm-wide basis) drops from 12.5% to 11.8%. If no increase in equity costs occurs, the reduction is to 11%. If the low 5% coupon is available, the cost of capital reduces to 10.8% or 85% of the non-tax free bond case.

From the preceding examples it appears that given an already economic project, Tax Exempt bonds (if feasible) could help to increase profits marginally. Given an uneconomic project, they cannot help absent 100% guarantees and/or non-recourse to the EOR operator.

8.5.5.5 <u>Structure</u>

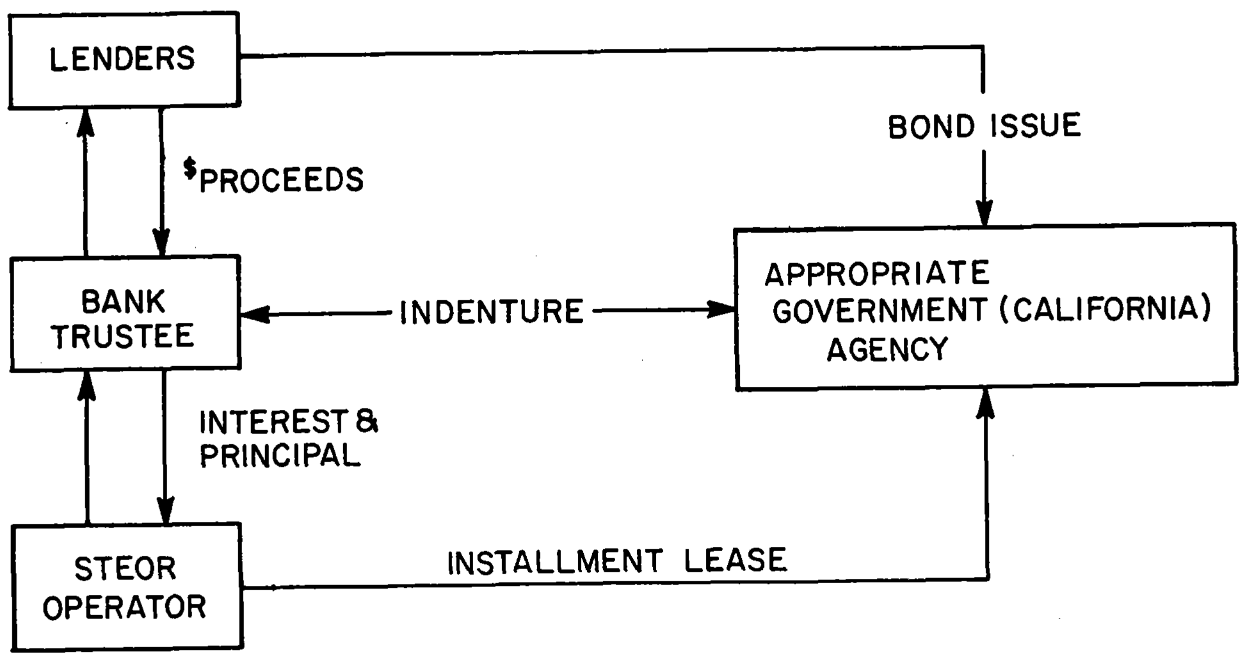
For completeness, we have included an example of the structure applied to a tax exempt bond. In its simplest form (as shown Figure 8-33) the state agency would issue the bonds to the lenders. The ownership of the STEOR solar facility could have been arranged in several ways, for example,

- o Revenues from the bonds would be used to finance the STEOR equipment which would be owned by the State, municipality, or other political subdivision which issued the bonds. The facility would then be leased to an operator for an amount necessary to pay the interest and amortize the principal on the bonds.

- o With the issuing agency acting as an intermediary, the proceeds of the bond issue would go to a private concern to finance equipment for removing, altering, disposing, or storing of pollution, contaminants, waste, or heat. The equipment would be owned by the private business entity which would make installment repayments to the state to cover the principal and interest of the bonds.

In the event of a default by the operator on his take-or-pay contract (or installment repayments) the trustee would take over.

While the structure shown assumes that the bonds appear on the EOR operators balance sheet, it is possible if tax exempt bonds were to become feasible for STEOR, a case could be advanced for leveraged leasing with



GENERAL STRUCTURE OF TAX EXEMPT
POLLUTION CONTROL BONDS
FIGURE 8.33

partial tax exempt financing. In that event, the impact would be to improve upon the already noted financial advantages of leveraged leasing.

8.5.6 Economic Methodology

The approach used to evaluate the quantitatively analyzable economic questions was to use a discounted cash flow algorithm STEORE, Solar Thermal Enhanced Oil Recovery Economics. Appendix.I provides the summary cash flow equation. This equation uses standard discounting techniques such as are found in references (8-116, 117) for example.

8.5.6.1 Performance Measures

The economic measures of performance other than net present value and net cash flows are the result of manipulations of the basic equation. The Internal Rate of Return is the discount rate at which the net present value is zero. (8-118)

If solar fails to provide the specified return, a government grant is estimated. If one accepts government grants (e.g. cost shares) then one's book value basis for calculating tax credits is reduced dollar-for-dollar by the outside funds. The algorithm iterates until it converges on the amount of grant which will result in an NPV = $0 at the specified discount rate.

If all other economic parameters are known, a variant of the algorithm can be used to solve for the cost per unit area of the system - a design to cost number. Another useful output of the algorithm is a levelized cost of energy (Life Cycle Cost). The algorithm estimates this cost from the NPV by multiplying by an annuity factor, that is, the factor which will convert NPV into an equivalent series of equal current dollar value, annual payments over the life of the system. This is the "standard" methodology. Appendix I details the P.R.P. life cycle cost methodology which was used by Foster Wheeler to find the before-tax cost of energy in its tradeoff studies. The important difference is that while the P.R.P. method generates a series of equal constant year zero dollar payments (escalated by the general inflation rate into unequal current dollar payments), the standard LCC method generates a stream of decreasing constant dollar payments (but equal current dollar, i.e. inflated payments). Both methods yield the same net present value and both must be uniformly applied to both fossil and solar. As is shown in Appendix I, the after-tax PRP annualized, Po, cost is always less than or equal to the LCC annualized cost Ro.

8.6 Market Summary

8.6.1 INTRODUCTION

This section summarizes the results of the preceding market, economic and environmental investigations and indicates some of the limitations on their findings. It also discusses some of the follow-on research topics (i.e. market penetration) which could be helpful to acquaint government, solar manufacturers and oil producers with the key issues in the application of solar energy to steam enhanced oil recovery.

8.6.2 FINDINGS

The focus of our efforts has been to examine factors which may determine the long term viability of STEOR. The near term opportunity for testing STEOR in initial pilot plants is made possible by the availability of tax credits and oil price rule incentives (TIR). However, it appears that neither the oil producers nor the solar manufacturers could be expected to take the steps necessary to establish an early ongoing STEOR business, unless one of two circumstances occurs by September 30, 1981:

a. Solar energy costs drop to the point of life-cycle energy cost parity with the preferred fossil alternative (oil or coal),

or

b. Solar energy costs drop significantly and new incentves are enacted which establish cost parity.

In addition, our Section 8.3 findings have indicated that when both oil field operations and solar economics were considered together, the siting of the collectors adjacent to, but away from the oil wells appeared to be desireable. The use of an offsite location would preserve the oil field operator's ability to drill new or replacement wells without the need to remove or relocate collector arrays. The added energy costs associated with the longer runs of pipe from the collectors offsite to an onsite use point would appear to be counterbalanced by reductions in pipe runs resulting from the consolidation of the collectors from multiple groups interspersed among wells into a single compact block.

Comparative economics have also shown that a preheat-only distributed line focus collector system, which has an inherently higher thermodynamic efficiency, appears to be preferable on a cost per unit energy basis to a distributed line focus collector steam raising system. This advantage could also be operational, because a preheat system may be designed to be relatively independent of wellhead pressure requirements, while a steam system could not. The lower pressures and temperatures in a preheat system should also result in relatively fewer maintenance problems relating to overheating or loss of fluids.

Beyond these economic concerns other market factors have been considered by our study. Section 8.3 has shown that on the basis of topographical suitability only, sufficient unimproved land appears to be located on or adjacent to the reservoir sites studied to permit the installation of sizeable solar facilities.

The other, non-topographical land use questions of acquiring surface rights, plans for future non-petroleum related use and overall environmental and social impact have not been formally addressed (8-119). (Informal discussions with the Kern County Agricultural Agent did suggest that if farm land were available at current prices of \$0.75 to \$1.50 per sq. meter (\$3000 to \$6000 per acre), then the cost of solar at packing factors $\geq$ 0.25 would be increased by less than \$6/sq. meter (\$0.56/sq. foot) versus about \$660/sq. meter (\$61/sq. foot) for the labor and materials in the preheat system (see Section 8.5.2.4 and Reference (8-120)). Section 8.4.3 notes that adoption of solar energy to displace lease crude oil in steam generation should linearly reduce total pollutants.

Current oil price incentives (e.g. T.I.R.) may make certain risky investments in pilot STEOR facilities marginally attractive. Financing programs based upon traditional prudent lending practices cannot be expected to make low return solar investments attractive today. The absence of several years of operating data could be expected to keep conventional lenders inaccessible to any leveraging arrangements based upon STEOR projects. Once favorable data exists, financing could increase market penetration assuming STEOR is already an economically attractive investment.

8.6.3 MARKET POTENTIAL AND MARKET PENETRATION

Although we believe that our market studies have shown that a potential situation might develop which could allow solar to displace significant amounts of fossil energy, the studies did not directly address market penetration. The term "penetration" we would define here as "achieving specific displacements of fossil energy by specific times". The term "potential" merely indicates the upper volume of applications where solar could be used, if it was already economic. The connection between potential and penetration is in part behavioral (lag effects). We have addressed these concerns in the following sections.

8.6.3.1 Market Condition Effects

One simple "model" or scenario for significant early market penetration by STEOR would argue that as a minimum four market condition assumptions would need to be true in the near term:

1. California TEOR steam capacity expansions track the results of our producer survey.

2. Solar shows a significant economic advantage over fossil fueled systems.

3. The potential negative aspects of solar are discounted by users: i.e. operational uncertainty, preemption of marginal agricultural land, seasonal and diurnal output variations; and sensitivity to airborne contaminants of agricultural and combustion origin.

4. A strong investor consensus develops on the attractiveness of solar based investments, among both equipment manufacturers and oil field operators.

Secondary assumptions would also be required, e.g. insurability, but we presume there that they are included in the preceding list.

Expansion of Operations

If California steaming capacity and TEOR operations expand, a natural tendency to consider solar could develop. Prudent oil field operators would then reexamine past equipment choices (oil boilers) in light of current realities. If solar were economically superior, it could be selected. On the other hand, if production were static or declining, then one could easily see difficulties in justifying any new capital investment such as STEOR.

Economic Advantage

If solar were to show a one-to-two year payback over oil fired operations, its salability would be greatly enhanced. If solar were only marginally attractive (a 5-10 year payback), then there could be a strong tendency among users to conclude that a risky solar investment could not be justified. Regulatory effects notwithstanding, delivered solar energy costs would probably need to be under $6.63/10^9J ($7/MBTU) to have marginal economic attractiveness.

Negative Aspects

Solar would have to be shown capable of overcoming potential operational and land use problems. For example, oil field boilers in many cases are expected to be running a high percentage of the time. Operators would probably want to apply similar goals to solar. Also, current fossil systems with multiple boiler "parks" provide relatively constant daily and yearly energy flows. Line focus troughs exhibit energy variations which superimpose daily sunlight cycles on daily (E-W axis) or yearly (N-S axis) end loss patterns. Either the reservoir would have to be buffered from these energy rate effects by storage and floating surplus fossil reserve capacity, or the reservoir and its equipment would have to be shown insensitive to these effects. The widespreadapplication of solar could displace much marginal agricultural or grazing land (up to 30.2 million sq. M (325 million sq. ft.) of collectors which would occupy 85 x 10^6 sq. M (21,000 acres)) in the oil field environs. While this land preemption need not be permanent (e.g. one could have a 20 yr. lease), the potential for diversion of farm land to EOR steam generation could become an important land use issue in the intensively cultivated San Joaquin Valley. Lastly, since solar collectors are optical systems, the high particulate and SMOG levels in the valley could cause some concern about long term performance and cleanliness of mirrors and receiver shrouds. All of these problems will need early resolutions, before a sizeable STEOR market could develop.

Early Investment

Whether the government and the solar community will be able to accomplish their industry development objectives would appear to depend upon the willingness of the investors (both private and institutional) to risk their capital in both the production and ownership of solar equipment. Current estimates of cumulative industry production are under 46,500 sq. M (500,000 sq. ft.)

(8-121). The 1990 theoretical maximum STEOR potential suggested by Section 8.3 exceeds 27,870,000 sq. M (300,000,000 sq. ft.), a six hundred fold increase. Under the highly optimistic assumption that the current industry historical production could be doubled each year the industry would just be able to provide the (Section 8.3 maximum practical total) STEOR demand by 1989. Using $108/M^2 ($10/ft^2) as an equipment price and assuming that (as in Section 8.2) (change in sales) = 2 times (change in investment), the cumulative sales would be over $3.8 billion and the added manufacturing investment would need to be about $638 million. (See Table 8.21).

The Table 8.21 numbers, although large, still understate the magnitude of the collector manufacturing investment challenge. If we assume that the Section 8.3 projected steaming capacity additions occur linearly between 1980 and 1990 and if we also assume that the solar potential is for new systems only, then low solar penetration in early years cannot be overcome in later years. This is because new fossil equipment will already be in place before solar equipment could be available. As an approximation to the near term build up, we have developed a log linear estimate of the production and resulting investment assuming solar achieves a cumulative installation of about 5.57 million sq. M (60 million sq. ft.) by 1985 (about 20% penetration) from a producing rate of 0.05 million sq. M/yr. (0.5 million sq. ft./yr.) The results of the following table appear in Figure 8.34.

Year	Producing Rate/YR (10^5 sq M	(10^6 sq ft)	Cumulative (10^5 sq M	(10^6 sq ft)	Investment (Million $)
1981	0.05	(0.5)	0.05	(0.5)	
1982	0.14	(1.5)	0.19	(2.0)	5.0
1983	0.42	(4.5)	0.61	(6.5)	15.0
1984	1.24	(13.4)	1.83	(19.9)	44.5
1985	3.72	(40.1)	5.57	(60.0)	133.5
	5.57	(60.0)			$198.0

Here, we see the collector manufacturing investment at $198 million, $108/sq M (10/Sq. Ft.) to $297 million ($15/Sq. Ft.). Assuming systems costs were double to triple collector-only costs, the implied cumulative oil field owner investment would be: 5.57 x 10^6 sq M (Sales) x $108/sq. M (Price)* 2-to-3 (System Price)/Collector Price) = $1.2 to $1.8 billion by 1985 (before incentives). At 945KWh/M^2/YR (0.3 MBTU/ft^2/Yr), and Edison field boiler parameters, the cumulative installations would imply 3 million BBL's saved per year. If this were a 20 year situation, the gross capital cost per barrel saved would be ($1.2 billion/(3 million BBL/Yr. x 20 yrs)) = $20 (before incentives). If the solar equipment could be used for only 15 years, the gross cost per barrel would be $26.67. If solar capital costs were $646/sq. M ($60/sq. ft.) vs $215/sq M ($20/sq ft) (a point closer to today's costs), the equivalent oil gross cost would be $60/BBL, (about twice current oil prices before WPT, local taxes and royalties are included per Section 8.1).

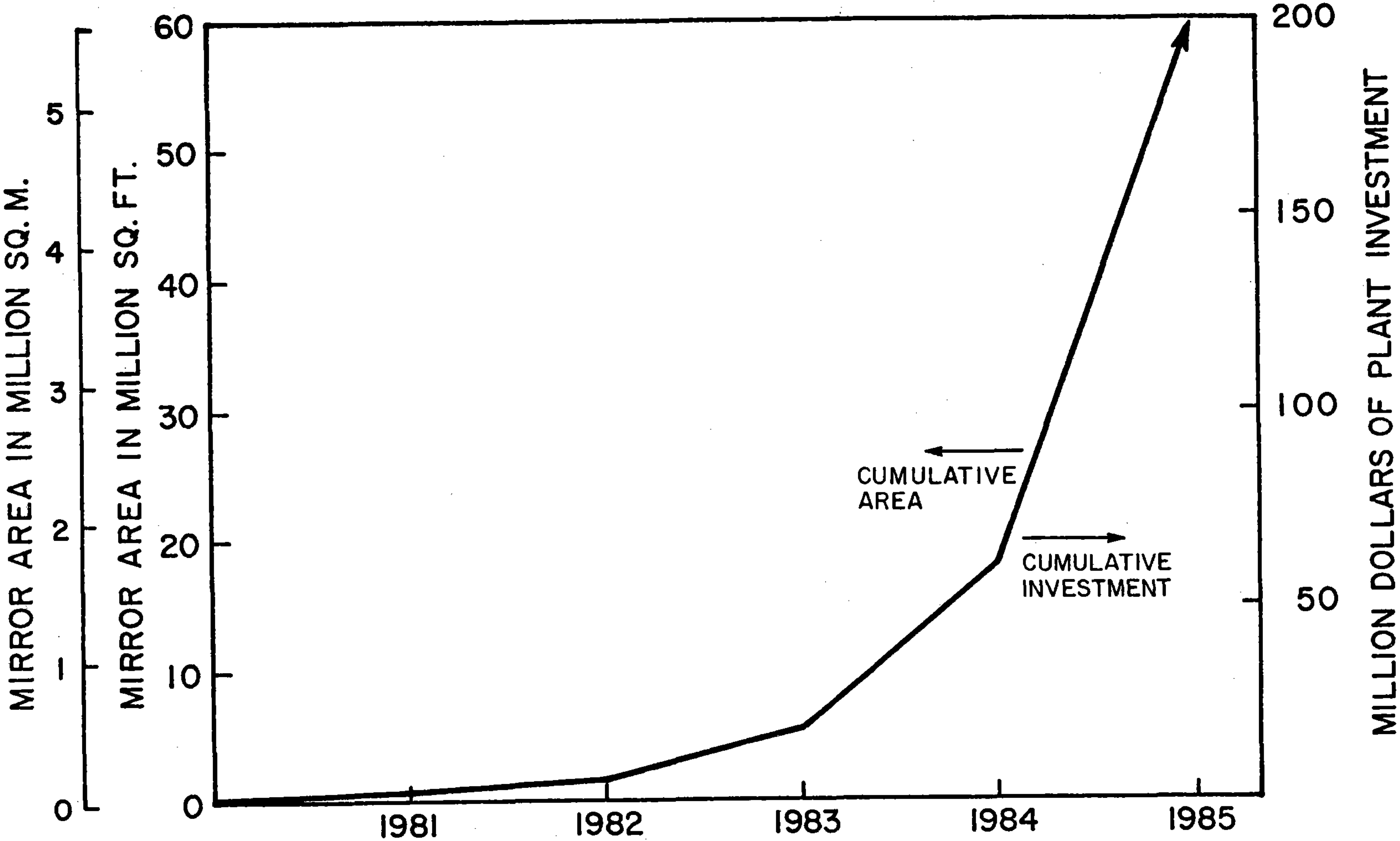
Table 8.21

Investment Implied By Rapid Trough Industry Expansion For STEOR
(Millions of Sq. Ft. and Millions of $)

YEAR	ANNUAL OUTPUT (Units)	CUMULATIVE OUTPUT (Units	(% of 325)	EQUIP. SALES REVENUE	MANUFACTURERS ADDED INVESTMENT
1981	0.5	0.5	(-)	$ 5	$ 0
1982	1.0	1.5	(-)	$ 10	$ 2.5
1983	2.0	3.5	(1%)	$ 20	$ 5.0
1984	4.0	7.5	(2%)	$ 40	$ 10
1985	8.0	15.5	(5%)	$ 80	$ 20
1986	16.0	31.5	(10%)	$ 160	$ 40
1987	32.0	63.5	(20%)	$ 320	$ 80
1988	64.00	127.5	(40%)	$ 640	$160
1989	128.00	255.5	(79%)	$1,280	$320
1990	128.00	383.5	(119%)	$1,280	$ 0
Total	383.5			$3,835	$637.5

Results Assumed:

1. $10/Sq. Ft. in constant dollars.
2. Ratio of $\frac{\text{new sales}}{\text{new investment}} = 2$
3. Output doubles every year until 1989.
4. 325 million sq. ft. is Section 8.3's estimate of STEOR market potential.



CUMULATIVE AREA INSTALLED AND
IMPLIED INVESTMENT FOR A 20% PENETRATION
BY 1985

FIGURE 8.34

8.6.3.2 Behavioral Lags

If we assumed that all of our favorable market conditions could be met by 1981, (e.g. solar has competitive economics through the combination of a appropriate tax incentives, modular system designs, and equipment production volume cost savings), one would still need to contend with market lag effects. Some examples follow. Taking Edison STEOR as an example, a construction project may require about 2 1/2 years from first consideration to estimated completion of construction. Collector vendors could be expected to quote 3 to 6 month lead times on delivery of collectors. Their subtier vendors will likely quote similar lead times on delivery of new machine tools. Large, mass production plants can easily take two years to obtain. Oil field pilot tests often take several years. The raising of significant outside capital can take several months to one or more years. If we could combine all these lags on a critical path, we could easily hypothesize a standard one-to-two year lag for each significant manufacturing capacity increase (decision-to-execution) and another year or so to consolidate and evaluate each investment. Thus one might see a three year delay between major bootstrap steps in market size. Only by having many participants can the above mentioned doubling scenario be achieved, and this would require much overlap and paralleling at the industry level.

8.6.4 SUMMARY

We consider the market outlook for STEOR to be mixed. In the near term we see a possibility that several pilot systems will be installed using TIR. Not all of these will use line focus collectors, but line focus technology could be present. The near term impact would be a short spurt to the collector manufacturers and should provide synergistic benefits with other DOE projects in process heat and modularity of trough systems.

Once the TIR program terminates, a large economic gap will again exist. Given current oil prices, the Windfall Profits Tax, and solar prices, the economics of STEOR will be unfavorable. The modest reduction in solar hardware costs resulting from a few early STEOR pilot plants cannot be expected to improve system cost effectiveness enough to overcome the burden of current industry design and construction practices which were developed for process plant applications. An opportunity (with large business risk) could exist for an inventive approach to use multiple unit production methods to cut recurring system design and procurement costs (e.g. "Liberty Ship" approach).

The alternatives to line focus technology-based STEOR should also be considered. Point focus technology (e.g. heliostat central receivers) may be inherently more attractive, depending on the actual experience of forthcoming operational demonstrations. The DOE may find it desirable for its objectives to provide assistance either directly or indirectly to induce the owners of any pioneering STEOR projects to try again on a larger scale. The objective of such follow on efforts should be to provide a fair test of STEOR and to provide private decision makers with additional operational and economic information upon which they can prudently evaluate both risks and benefits of STEOR investments as either manufacturers or users.

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8-107 See Reference 8-83 p. 4, item 9.

8-108 See Reference 8-83, pp. 317-18 that the lessors investment-at-risk (i.e. equity) which indicates must be 20% or more of the asset at all times.

8-109 See Reference 8-108.

8-110 See Reference 8-91.

8-111 See Table in Appendix I.

8-112 Communication by the "Solar Cal" office to Exxon Research's consultant Technology & Economics, Inc.

8-113 Anonymous, "32nd Annual Report on American Industry" Forbes, January 7, 1980, p. 72: Energy inustry medians were R.O. Equity = 15.1%, Debt/Equity = 0.4, R.O. Capital = 11%, which implys a debt rate = 9.7% at 50% taxes.

8-114 See Reference 8-69, p. 646 for a discussion of Modigliani-Miller.

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8-119 See Reference 8-63, Sections 4.1 and 5.1 discuss these issues.

8-120 Costs based on personal communication by the Kern County Agricultural Agent with D.C. Arnold of Exxon Production Research Company. The 1977 County and City Data Book (US Census) would suggest that the section 8.3 upper limit collector areas represent a total less than 0.4% of Kern County land area and less than 2.8% of harvested crop land in the county. Our site visits suggested that much of the land shown in the section 8.3 figures is not harvested crop land.

8-121 See Section 8.2.

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