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SOLAR CENTRAL RECEIVER PRELIMINARY DESIGN STUDIES

Summary and Review of Contract Results

By
Prem K. Munjal

April 1, 1985

Work Performed Under Contract No. AI03-81SF11578

The Aerospace Corporation
El Segundo, California

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U.S. DEPARTMENT OF ENERGY
San Francisco Operations
Oakland, Calif. 94612

FOREWORD

The U.S. Department of Energy (DOE) has, for a number of years, supported the development of solar thermal technology by supporting a succession of research and development contracts involving conceptual, advanced conceptual, preliminary and final design studies for large-scale solar central receiver (SCR) projects. The Aerospace Corporation has assisted the DOE, San Francisco Operations Office (DOE/SAN) by participating in General System Engineering and Integration (GSE&I) activities.

This report presents a summary and review of the results of four major SCR preliminary design studies. Observations as to the accuracy and system level importance of the data are made. Considerable independent analysis was done to evaluate selected design issues, fill in gaps or adjust data where appropriate, perform economic evaluations, and interpret the many facts and indications as measures of the current state-of-the-art for solar thermal central receiver technology. A companion Executive Summary report (ATR-85(5836)-2ND) has also been prepared that covers the principal findings of this report but in the form of charts with explanatory texts.

This report was prepared by Dr. Prem Munjal, who is the Project Manager and Principal Investigator of the Aerospace Solar Thermal Program. The Solar Thermal Program at The Aerospace Corporation is part of the Energy Systems Directorate. Dr. Mason Watson is the Principal Director of the Energy Systems Directorate. Overall cognizance for this effort was provided by Mr. Robert Hughey with initial guidance by Dr. Keith Rose of DOE/SAN. Ms. Kathy Morris has been responsible for the extensive word processing required to produce this report.

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CONTENTS

CONTENTS (Cont'd)

List of Figures

List of Tables

SUMMARY

The U.S. Department of Energy (DOE) has, for a number of years, supported the development of methods to use solar thermal energy in the generation both of electricity and of industrial process heat (IPH). Of the various solar thermal technologies that have been investigated, the solar central receiver (SCR) concept is considered to be the most promising for both large-scale power generation and high-temperature production of thermal energy. The technical feasibility of the SCR approach in large-scale electricity production has been demonstrated in the successful construction and operation of the 10 MWe solar pilot plant near Barstow, California (Solar One). However, the capital cost and performance of such systems, expressed in terms of dollars per unit production, do not yet permit the technology to be economically competitive with more conventional energy sources. To address this problem, the thrust of the DOE Solar Thermal Technology program in recent years has been directed toward improving the overall efficiency of SCR components and systems without unduly increasing the cost. The DOE program efforts, in partnership with the solar industry, have resulted in significant improvements as measured by performance vs cost in the design of heliostats, receivers, thermal storage systems, steam generators, and system controls.

In early 1982, DOE initiated a cooperative government-industry program a) to develop preliminary designs and design specifications for SCR plants that would have the maximum likelihood of being constructed and would incorporate the improvements in SCR components that had been made since the design of the Barstow pilot plant and b) to provide accurate and detailed estimates of system performance and cost. Contractors could select any concept, design or location of their choice. Four different site-specific SCR system designs were developed, on a cost-shared basis, by four industrial design teams led by Amfac, Rockwell, Arizona Public Service (APS) and El Paso Electric Company (EPE).

The four preliminary design studies developed a large amount of valuable information and represent the most important reservoir of current technical documentation after the design of the Barstow pilot plant. The

accessibility and usefulness of this information was somewhat reduced, however, by the very large volume of the documentation (15 volumes, 5500 pages) and by differences in nomenclature and the organization of the reports. In addition, a comparative evaluation of the designs was made difficult by a) design differences arising from differences in the sites and the applications for which the system were intended, b) differences in assumptions about cost and performance of some elements and about several other cost factors, c) differences in the level of detail of the reports, and d) apparent internal inconsistencies in some of the design descriptions. For this reason, The Aerospace Corporation was asked to examine the entire body of information critically and to prepare a report summarizing the design information and providing an unbiased and objective comparison. Other secondary objectives of the effort were to identify, if possible, the more favorable SCR design concepts, assess the near-term construction potential of the proposed designs, and provide assistance to the DOE program planning activity.

In response to this request, Aerospace carried out the required examination and extracted, organized, and normalized the key technical data about the four designs. This report summarizes analyses done by Aerospace to evaluate and interpret these results, and notes observations and conclusions drawn during the review. It describes the key elements of the four SCR preliminary designs and compares their projected performance and cost on as consistent a basis as can be achieved. The report also identifies both meaningful and suspect significant differences in the data and assumptions, calculates benefits of the proposed designs allowing for maximum solar advantage, and assesses the cost-benefit gaps and breakeven requirements.

The four design teams used different SCR concepts (e.g. stand-alone, repowering of existing plant, and cogeneration). Except for the cogeneration plant (Maui, HI), the proposed solar plants, were generally located in relatively good insolation regions (CA, AZ, TX). These designs were developed for different plant sizes, (8-58 MWe) and collector areas

($54-284\times10^3 m^2$). They also used different receiver configurations (external, single and twin cavity) and working fluids (water-steam, molten salt and liquid sodium). Some used on-line storage, while others did not provide any storage and employed fossil boilers. Thus a diversity of designs, concepts, operating modes and plant sizes were used by the various contractor teams. The reported studies place heavy emphasis on plant design specifications and system operations and lack many details on performance and costs. Detailed descriptions of the solar designs, plant specifications and solar operating modes cover three-forths of the contractors documentation. Summary comparative descriptions of different plant designs, their schematic plant flow diagrams and specifications of collector, receiver and steam generation subsystems were developed and are presented in this report. It should be pointed out that these SCR designs were aimed at near-term actual construction with specific sites, applications and design concepts. The results indicate how much progress has been made over the last decade rather than prescribe a limitation of possible future achievements.

For each SCR design, performance comparisons of different subsystems and their elements were made and significant performance differences were observed. For example significant differences were reported by the different design teams in collector subsystem performance. In this case detailed examinations of the performance of collector subsystem elements revealed that one team (APS) used in-the-box heliostat reflectivity (92%) for the annual average value and is thus considered suspect. Heliostat reflectivity for the Amfac team is considered more reliable and meaningful as it is based upon several field measurements. Also, the low collector subsystem blocking efficiency for the Rockwell design is considered meaningful as its low value can be explained by the heliostat field layout. Similarly, other meaningful differences and suspect results were identified for different subsystems that were judged pertinent to the performance of the four designs. Since the overall plant system performance (efficiency) combines the efficiencies of all the subsystem elements, any suspect subsystem performance efficiencies would be carried through to the overall plant efficiency values. The annual plant electric outputs would then be suspect since these are calculated from the overall plant efficiencies and the annual insolation where these plants are sited. Suspect performance data and cost uncertainties will require more detailed analyses, component testing, and/or actual cost bids to be resolved.

The overnight plant costs (i.e. cost as if construction were completed overnight rather than over several years) of the four designs were also examined. Because the plant sizes were different, the subsystem costs are normalized as percents of the total plant costs. The various hardware components assigned to each subsystem cost account as reported by different contractors were not consistent. Components for each subsystem were thus identified and properly grouped for consistent cost comparisons inasmuch as could be achieved. The collector subsystem costs are also normalized on the basis of the reported heliostat areas. These normalized collector costs were found to be very different. The collector costs ($210-265/m^2$) of the Rockwell and the Amfac teams were based upon ARCO quotes and are thus well supported. The high costs for the APS ($369/m^2$) and the EPE ($317/m^2$) plants were questioned and considered suspect. The differences in collector costs appeared to be very high and in order to carryout meaningful performance-cost comparison of alternative SCR designs, the collector subsystem costs for the APS and the EPE designs were adjusted downward to $250/m^2$. Similarly, other meaningful differences (e.g. power generation, storage) and suspect differences (e.g. indirect costs) are identified (see Sections 4 and 5).

Actual project costs (not overnight costs) that include the effects of cost inflation and the time value of invested money are also compared. Present worths of these project costs were calculated for a reasonable, if optimistic, set of assumptions (15% discount rate). For relative comparison, these costs were normalized over collector areas and are found to be around $900-1000/m^2$. This normalization method can compare the cost-performance of an SCR design with other solar thermal technologies involving parabolic troughs and dishes. Normalization over solar output power capacity was done to compare SCR plant costs with other conventional power plants (e.g. nuclear, coal). Normalizations of SCR plant costs over their annual energy production were presented ($2100-2300/MWhe) to obtain an insight to the relative merits of the individual SCR plants. Comparison of the four design results did not support selection of one design concept over another. Except for the relatively small Amfac cogeneration plant, the performance-cost relationship of these plants is very close, about 430-470 MWhe/ $million.

On the basis of this, selection of a preferred design was difficult especially considering the suspect nature of the input data (e.g. collector costs, indirect costs, operating loads, collector reflectivity, etc.). Corrections to some of the suspect data (e.g. collector cost, indirect cost) were made, where such corrections were rather straightforward and did not require reworking of the detailed tasks assigned originally to the contractors (the product of 80 to 90 man years of technical effort). However, the uncorrected suspect differences seem to be larger than the meaningful differences (e.g. receiver thermal losses, field blocking, power generation, receiver spillage, etc.) Selection of a preferred design is further complicated by differences in other factors such as insolation, plant size and plant application.

Nevertheless, the four studies have produced valuable information on current solar plant designs. These design studies have established a believable range of collector subsystem costs ($200-250/m^2). The design studies have shown that current SCR plant costs should be approximately $900-1000/m^2 with an annual current performance of about 450 MWhe of electricity per one million dollars of investment.

Comparisons and evaluations of annual O&M personnel requirements, labor, and materials costs were also made. The very low O&M personnel requirements for the EPE plant appear suspect. The labor rates for the Rockwell plant are high by a factor of 2 as compared to the other plants.

Annual total O&M costs were analyzed as percents of both project costs and annual gross revenues. It is shown that for the reported designs the annual O&M costs are expected to consume 2/5th of the solar revenues. If property taxes were to be paid on SCR plants, the annual O&M costs could consume 2/3rd of the generated revenues. The importance of reduced net revenues because of O&M costs is accentuated where a project is to be financed partially with debt and net revenues must be sufficient to service debt payments.

The energy rates that affect SCR revenues are inconsistently presented by different contractors. The Amfac team used an electric rate that is about twice as high as the projected rate of Maui Electric to whom this electric energy would be sold. The APS team used a very low value for estimating energy revenues that was based upon only fuel savings. Meaningful comparative evaluations of different plant revenues and an assessment of the construction potential required revision of these reported values for consistency and maximum solar benefit. Thus the annual revenues of different SCR plants were calculated on the basis of the maximum avoided energy and capacity credit rates of different utilities where the SCR plants are sited. The calculated annual SCR net revenues, presented as percents of project costs are very low ranging from 2 to 4 percent of project cost.

The treatment of tax benefits by the different contractor teams is inconsistent and inadequate. This situation is further complicated as different teams assumed different types of plant ownership with varying assumptions for economic parameters and returns on capital investments. These tax benefits play a key role in the expected viability of constructing a privately funded plant at this time. In order to assess the construction potential of different plant designs and to obtain the maximum tax benefits, an independent analysis was carried out that is based upon the contractor data, consistent economic parameters, and assumes a third-party ownership. This analysis used standard tax benefits including investment tax credits, depreciation, and interest deductions that apply to most business ventures under current (1984) tax provisions. Leveraging benefits were obtained by first calculating the maximum amount of debt that can be serviced from the net revenues of different SCR plants. Where the cost of debt is less than the required return (discount rate) the maximum leveraging serviceable from net revenues also maximizes benefits. The 30-year present worth of the benefits attributable to leveraging were calculated at 15% discount rate, 30-year debt at 12% and a 50% tax rate. Similarly, the 30-year present worths of other standard and special tax benefits were also calculated for different SCR plants.

Under the above assumptions, the standard tax benefits recover 37% of the SCR project costs and with the extension of special federal energy credits, these tax benefits could recover almost half of the project cost. By comparison, energy revenues and leveraging benefits for different SCR plants recover 15-20 and 9-17 percents of the project cost. It is estimated that, total SCR plant benefits with the extension of energy tax credits, will be 3/5th to 4/5th of the plant costs. Without energy tax credits, benefits will be only one-half to two-thirds of the plant costs.

Standard tax and leveraging benefits appear to be very important in current SCR plant economics and together they recover about 50% of the plant cost. It is noted that these tax and leveraging benefits are available to most industrial investments and solar plants are not unique to obtaining such benefits. However, due to low energy revenues, the near term economics of all the proposed SCR plants are not favorable. Larger cost gaps (costs minus benefits) are projected for the larger plants. This suggests that the operation of solar plants may be best demonstrated initially through relatively small plants. The scale and efficiency advantages of a large turbine might still be captured by operating a small solar facility in a hybrid mode at a large fossil plant. It is observed that non-engineering issues appear to be very dominant in the near term solar plant economics. For example, ability to take advantage of different tax benefits and plant siting in high energy rate area are very essential.

Breakeven plant requirements for competitive, privately funded future SCR plants were also calculated. It is observed that unless SCR plant owners are willing to accept a lower return (5 to 10%) on their investment, current plant costs must be reduced or the energy revenues must be increased to breakeven (100% recovery of invested capital at 15% rate of return). Breakeven plant costs were calculated through an iterative procedure that includes lower tax benefits due to lower plants costs. It is pointed out that increased energy revenues are possible with higher energy rates, higher plant performance, or lower O&M expenses. Breakeven energy prices were also calculated through a similar iterative procedure which account for increased leveraging benefits made possible by an increased loan servicing ability.

Based on the four contract studies, either the current plant costs must be reduced to one-third (2/5th to 1/3rd) or real energy prices must double (2 to 2.5 times) if there are to be many privately-funded, commercial solar plants. An equivalent combination of lessor improvements in cost, performance and energy prices may also provide for economically competitive solar plants. The effect of collector cost reduction to $80/m^2 is similar to reducing system costs to about three-fourth. Demonstration of a net 25% overall plant efficiency is like improving system performance by 25%. Reductions in O&M costs by half would be equivalent to an increase in system performance by about 20%. The combined effects of these improvements would be as if the real energy prices were doubled. Any increase in actual energy prices would be an additional benefit. The potential contribution of new and ongoing DOE program activities can be estimated by using these system level relationships. It is noted that for favorable geographic locations (e.g. California), competitive, privately funded solar plant economics could result much earlier with lesser levels of improvement.

1.0 INTRODUCTION

1.1 Background

During the spring of 1982, the U. S. Department of Energy (DOE) released a Program Opportunity Notice (PON) to solicit proposals to cost share in one or more preliminary designs for site specific solar central receiver (SCR) repowering applications (Ref. 1). The word "repowering" in this context referred to a SCR facility that is added to an existing electric power generating facility, industrial process heat (IPH) facility, or a cogeneration facility. New SCR electric and cogeneration facilities with or without fossil backup, which displace or reduce usage of fossil fuel in an existing grid were also included in this definition of "repowering".

The basic objective of the above cooperative efforts was to develop preliminary designs and design specifications, and provide accurate estimates of system performance and costs of different proposed SCR repowering facilities with potential for future construction. Also, since the Barstow Pilot Plant was designed, significant improvements had been made in such areas as heliostats, receivers, thermal storage, steam generators, and system controls. The preliminary designs were to incorporate these system improvements and SCR technology which represented state-of-the-art development.

As a result of the above mentioned PON, contract awards were made to four industrial teams that developed four different preliminary designs for their proposed SCR repowering facilities. These four industrial teams headed respectively by the prime contractors of Amfac, Rockwell, Arizona Public Service (APS), and El Paso Electric Company (EPE) are given below:

Amfac Energy Inc.	Rockwell Int'l Energy Systems Group	Arizona Public Service	El Paso Electric Company
Bechtel	Pacific Gas & Electric	Martin Marietta	Stone & Webster
Foster Wheeler	ARCO Solar	Black & Veatch	Babcock & Wilcox
ARCO Solar		Babcock & Wilcox	Westinghouse
		American Technigaz	IIE, Mexico

All of the above prime contractors except for Rockwell were the owners and operators of the existing facilities proposed for SCR repowering. The Rockwell team selected a new electric facility site where the proposed SCR plant would operate without a fossil backup.

Between October 1982 and December 1983, the four teams (17 contractors) developed four different SCR preliminary designs and reported, their work in 15 volumes that covered over 5500 pages of design related documentation (Ref. 2 through 5). Subtitles which suggest the scope of these 15 reports are given below. (See References 2-5 for complete titles).

Amfac	Rockwell	APS	EPE
Final Report	Executive Summary	Executive Summary	Final Report
	Plant Specifications	Preliminary Design	Analysis & Drawings
	Design Descriptions	Specifications	Design Descriptions
	Design Drawings	Appendices	
	Appendices	Drawings	
		Financial Analysis	

The effort of the Amfac design team was carried out with Amfac Energy Inc. providing project management, documentation, data on existing facility and solar insolation model. Bechtel Group Inc. was responsible for design of receiver tower, thermal transport, collector foundations and field wiring, master control and system integration as well as estimates of plant performance and cost data. Foster Wheeler Solar Development Corp. was responsible for the design, performance and cost estimates of the receiver. ARCO Solar Industries provided design, performance and cost data on the collector subsystem.

The design effort for the Rockwell team was carried out with Rockwell International Corp., Energy Systems Group responsible for receiver, thermal transport, storage and steam generation; Pacific Gas and Electric Co. (PG&E) for electric power generation, master control and balance of plant; and ARCO Solar for the collector subsystem.

The APS design effort was carried out with APS responsible for program management and economic analysis; Martin Marietta for system requirements, system interface, design specifications and configurations for collector, thermal transport, storage, master control, and overall design analysis and performance estimates; Black & Veatch Consulting Engineers for design and analysis of solar-fossil interface, receiver power, electric power generation and data on existing facility and SCR capital plant cost; Babcock & Wilcox company for receiver and solar steam generation, and American Technigaz, Inc. for assistance in storage subsystem and drawing preparation.

For the EPE design effort EPE was responsible for programmatic tasks and existing facility operations; Stone & Webster Engineering Corporation, for design and specifications of the receiver tower, thermal transport, master control, design integration, and cost and performance estimates; Babcock & Wilcox for the design, performance and cost of the receiver; Westinghouse Electric Corporation's Advanced Energy Systems Division for heliostat layout and performance, receiver flux distribution and economic analyses; Institution de Investigations Electricas (IIE), Mexico, (The Mexican counterpart of EPRI) for assistance in receiver performance during cloud transients.

The design efforts of the industry contractors were supported under cooperative, cost-share agreements with the following breakdowns:

Funding	Amfac	Rockwell	APS	EPE
DOE Award	$674K	$1341K	$2103K	$1814K
Industry Cost Share	140K	727K	264K	463K
Total	$814K	$2068K	$2367K	$2277K

The work of the design teams, other than Amfac, involved an intensive 12-months work schedule with peak workforce of about 40 persons for each design team. The intensive nature of the design effort with team members spread over different parts of the country and the requirements of large-scale documentation impeded the production of a well integrated set of reports that are consistent in terms of both data and level of detail for the various design tasks (specifications, performance, cost etc.), technical issues and subsystem components.

1.2 Objectives and Approach

The original objective of the effort covered in this report was to provide a summary and comparison of the four SCR preliminary design results as reported by the different contractor teams. The initial intent was thus to provide convenient access in a single report to the key elements and features of the contractor's efforts. These results were otherwise scattered and at times obscured in 15 different, lengthy reports that cover some 5500 pages of documentation.

A meaningful, unbiased and objective comparison of the design results is complicated because the various contractors did not report their efforts with the same level of detail, consistency and subject matter. Generally, the earlier tasks covering plant design, specifications and operating modes of the proposed solar facility were given more emphasis and the later tasks involving annual plant performance, cost and economics received less attention. Again, the various proposed designs were quite different in terms of both plant application (cogeneration, stand-alone, repowering, with-without fossil hybrid, new vs. existing facility, plant size, etc.) and plant design (collector field layouts, different types of external and internal receivers, water-steam vs molten-salt and liquid sodium heat transfer media, reheat vs single pass, with-without storage and type of storage, once-through to superheat vs preheater-boiler and superheater, natural vs forced circulation, etc.). Thus the proposed designs represent a diversity of both technology and application. A summary and comparison of the designs is given in Section 2.

During the review of the various contractors reports, significant differences were also observed in some of the key cost and performance data and parameters (collector cost, indirect cost, O&M cost, parasitic loads, plant outages, collector and receiver subsystem losses etc.). Some of these differences were observed to be meaningful and were due to the differences in the plant design and performance while the others were somewhat arbitrary and suspect. Thus, during the course of this review, observations were made relative to the consistency and accuracy of the reported contractor data. Appropriate remarks were noted whenever such differences were considered to be suspect or meaningful. Determination of the correct values for the suspect parameter, however, was out of the scope of the present report, except for the collector costs where such correction was possible and well supported without expending significant efforts. Collector cost variations exceeded 50% and without some normalization the performance-cost comparisons of the different reported designs would have been meaningless. Synthesis and comparison of the plants performance are summarized in Section 3. Plant costs, and operating and maintenance expenses are summarized in Sections 4 and 5 respectively.

During the course of this review, technical and economic data for different SCR design concepts and configurations were examined and compared. The performance-cost relationships of alternative SCR designs and the identification of any design concept that appeared to offer meaningful performance-cost advantage over other designs was sought. Also, in keeping up with one of the original objectives of the repowering studies, observations were also made to assess the potential for near-term (5-years) plant construction in a competitive environment. Solar plant benefits were calculated and revised from the reported results for consistency and to recognize maximum solar advantages in terms of displaced energy prices, capacity credits and tax benefits. A summary and comparison of plant benefits, both energy revenues and tax benefits, are given in Sections 6 and 7 respectively . This information was used to calculate benefit-to-cost ratios for the different proposed SCR plants. Observations were made to identify favorable factors that appeared important for near term plant construction. Assessments were also made to determine the current cost-benefit gaps for each of the proposed SCR repowering facility. Details of this effort and conclusions are summarized in Sections 8 and 9 respectively.

None of the proposed SCR designs were considered to have favorable near-term construction potential. It was considered appropriate to carryout analyses to determine breakeven (zero costs gap) plant requirements (Section 8) defined so that the four proposed SCR facilities would have favorable construction potential. These breakeven requirements also provide insight pertinent to the possible construction of privately funded SCR plants -- which is the ultimate objective of the SCR program. The current effort also serves to describe the current SCR system design status from which the DOE SCR Program can formulate an approach for ultimately fulfilling national objectives.

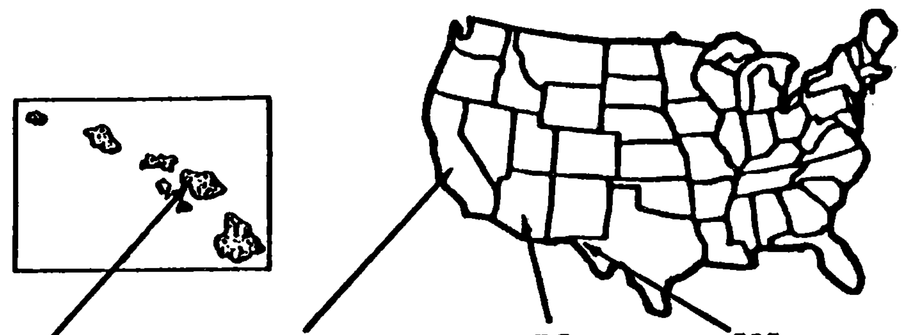
2.0 DESIGN COMPARISON AND SUMMARIES

2.1 Comparisons of System Features of Proposed Facilities

As discussed earlier (Section 1.1), the four industrial teams of Amfac, Rockwell, APS and EPE developed and documented four different repowering SCR preliminary designs (Ref. 2 through 5). All of these designs are site specific, and quite different in terms of both application and technology diversity. The Amfac design involves the addition of a solar central receiver to the Pioneer Sugar Mill Company, Ltd., an existing cogeneration facility near Lahaina, Maui, Hawaii. The Rockwell team designed a 30 MWe new stand-alone SCR plant to be located at Carrisa Plains along Highway 58 which is 80 km (50 mi) east of San Luis Obispo, California. The APS and EPE designs are based upon repowering of their existing power generating facilities. The APS design is sized to provide solar generated steam up to gross power output of 66 MWe (58 MWe net) for its intermediate-peak load Unit One of Saguaro Station, located on Interstate 10 approximately 43 km (27 mi) northwest of Tucson, Arizona. The EPE design provides solar steam for generating up to 46 MWe (42 MWe net) of power production for its intermediate load Newman Unit-1, located 24 km (15 miles) northeast of downtown El Paso, Texas.

Except for the Amfac plant site, the proposed repowering facilities are located in generally high insolation regions. Table 2-1 gives comparisons of the more important system features for each of the proposed repowering designs. The design point net solar power output is given after accounting for associated power generation losses. The Amfac SCR design is sized to provide up to 31.6 MWt of steam which is equivalent to a gross power output of 9.5 MWe (8.3 MWe net) if the plant were to strictly operate in a power generation mode. The Amfac gross turbine generating capacity is the sum of a main generating unit (8.4 MWe) and a secondary unit (3.4 MWe). The Rockwell design is based upon a thermal output of 106 MWt, of which 85 MWt are cycled to generate steam which produces 29.7 MWe of net electric power. The overall annual power generation efficiency in Table 2-1 is

Table 2-1. Comparisons of the Important System Features



	Amfac	Rockwell	APS	EPE
Site	Maui, HI	Carrisa Plains, CA	Tucson, AZ	El Paso, TX
Assumed Insolation	2307 kWh/m^2	2524 kWh/m^2	2519 kWh/m^2	2650 kWh/m^2
Function	Cogen	Stand-Alone	Repowering	Repowering
Design Point Net	8.2 MW_e	29.7 MW_e	58 MW_e	42 MW_e
Turbine-Generator	11.8 MW_e	32.7 MW_e	121 MW_e	86 MW_e
Overall Annual Eff.	8.5%	15.9%	16.8%	13.8%
Net Energy/Year	10.9 GWh_e/11.5 GWh_t	75.6 GWh_e	120.3 GWh_e	65.2 GWh_e
Capacity Factor	0.15	0.29	0.24	0.18
Gross Energy/Year	56 GWh_t	227 GWh_t	401 GWh_t	221 GWh_t

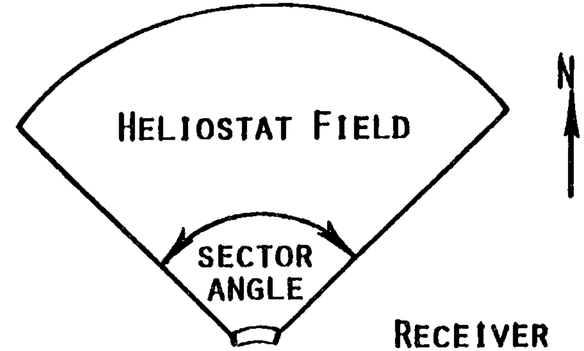
net of all operating loads and scheduled maintenance. The lower efficiency for the Amfac plant is due to both (a) operation of the facility in a cogeneration mode where the turbine is throttled to extract IPH steam, and (b) lower inherent turbine efficiency even for periods of exclusive power generation. The net energy produced per year due to solar repowering for the Amfac plant includes both the net power output and savings of fossil energy. The solar plant capacity factor represents the fraction of the time that the solar plant is producing net power at its peak design output. The gross annual thermal energy represents the solar plant steam output before losses due to operating loads and plant outages.

2.2 Comparisons of Major Subsystem Design Elements

Table 2-2 summarizes major solar design elements of the different proposed repowering facilities. The Amfac collector subsystem consists of 54×10^3 m^2 of ARCO third generation heliostats that are arranged in a 150^0 sector field. The sector angles of the heliostat fields as defined in Table 2-2 were approximately the same (~ semicircle) for the various designs except for the Rockwell design which has a right-angle field. Both the Amfac and Rockwell designs were based upon ARCO heliostats, while the APS & EPE designs respectively used specifications of Martin Marietta improved second-generation and generic heliostat designs.

The four designs also used very different types of receiver configurations and working fluids. The Amfac design used a twin-cavity natural-circulation steam generator with separate superheat circuitry. The Rockwell receiver design was an external, flat panel (billboard) configuration where liquid sodium is used to absorb and transport solar thermal energy. The APS receiver design used a single C-shaped cavity configuration and selected molten-salt for solar heat transfer media. The receiver design for EPE was based on a reheat concept which uses an external north-facing vertical cylinder configuration with water-steam forced recirculation. North-facing receiver configurations were used for all of the designs. Midplane receiver aperture elevations for the

Table 2-2. Summary of Major Design Elements



	Amfac	Rockwell	APS	EPE
Collector Subsystem				
Heliostat Area	54×10^3 m^2	178×10^3 m^2	284×10^3 m^2	178×10^3 m^2
North Field Sector	150^o	90^o	$\sim 150^o$	160^o
Type	3rd Gen. ARCO	3rd Gen. ARCO	2nd Gen. Martin	3rd Gen. Generic
Receiver Subsystem				
Type	Twin Cavity Water/Steam	Billboard Liquid Sodium	Single Cavity Molten Salt	External Cylinder Water/Steam
Midplane Elevation	79 m	125 m	155 m	155 m
Design Point Output	31.9 MW_t	107 MW_t	190 MW_t	111 MW_t
Storage Subsystem				
Capacity	None	99 MWh_t (1.1 hr)	688 MWh_t (4.0 hr)	None
Steam Generation				
Conditions	399^oC/5.97 MPa	538^oC/10.1 MPa	538^oC/10.0 MPa	538^oC/10.1 MPa
Capacity (max-min)	31.6-11 MW_t	85-8 MW_t	172-89 MW_t	111-10 MW_t
Turbine-Generator				
Gross Output (max-min)	11.8-2.0 MW_e	32.7-6.5 MW_e	121-30 MW_e	86-4 MW_e
Normal Output (net)	7.3 MW_e	29.7 MW_e	40 MW_e	80 MW_e

different designs ranged from 79 to 155 meters. Design point useful thermal output from the receivers ranged from a low of 32 MWt for the Amfac plant to a high of 190 MWt for the APS plant. The Rockwell and APS designs also used thermal storage. Liquid sodium storage capable of providing 1.1 hour of power generation steam supply was designed for the Rockwell plant. The APS design provided a molten salt storage capacity for 4 hours of operation.

All of the proposed SCR designs except for the Amfac plant were configured to deliver steam at $538^{o}C/10.1MPa(1000^{o}F/1465psia)$ to the turbine. The minimum steam generating capacities for the Amfac, APS and EPE correspond to the minimum fossil boiler output. For the Rockwell and APS designs, the maximum receiver thermal output exceeds the maximum solar steam generation capacities with the excess delivered to the storage systems. The maximum, minimum and normal turbine generator power outputs are also given in Table 2-2.

2.3 Comparisons of Solar Plant Operations

Figure 2-1 gives the simplified schematic flow diagrams of the four SCR repowering designs. The Amfac solar design produces steam conditions that are identical to those of the mill boilers. Also, the solar plant is sized such that; when it is producing its maximum steam output, the mill boilers that run continuously are operated at their minimum level. The mill boilers are designed for dual fuel operation with No. 6 oil and begasse -- a by-product biomass fuel produced by the operations of the sugar mill. Begasse provides about 72 percent of the annual energy input to the boilers. The solar facility is designed to displace the current oil consumption and in addition provide power to Maui Electric Company during the mill's off-season periods. The Amfac receiver design produces superheated steam at $456^{o}C/9.24$ MPa and due to steam transport losses, the conditions at the mill end of the pipe are $427^{o}C/5.96$ MPa. An attemperator is used to attain main turbine inlet conditions of $399^{o}C/5.97$ MPa by adding boiler feedwater. From this main turbine, high-pressure steam is extracted at $260^{o}C/1.83$ MPa to provide IPH steam

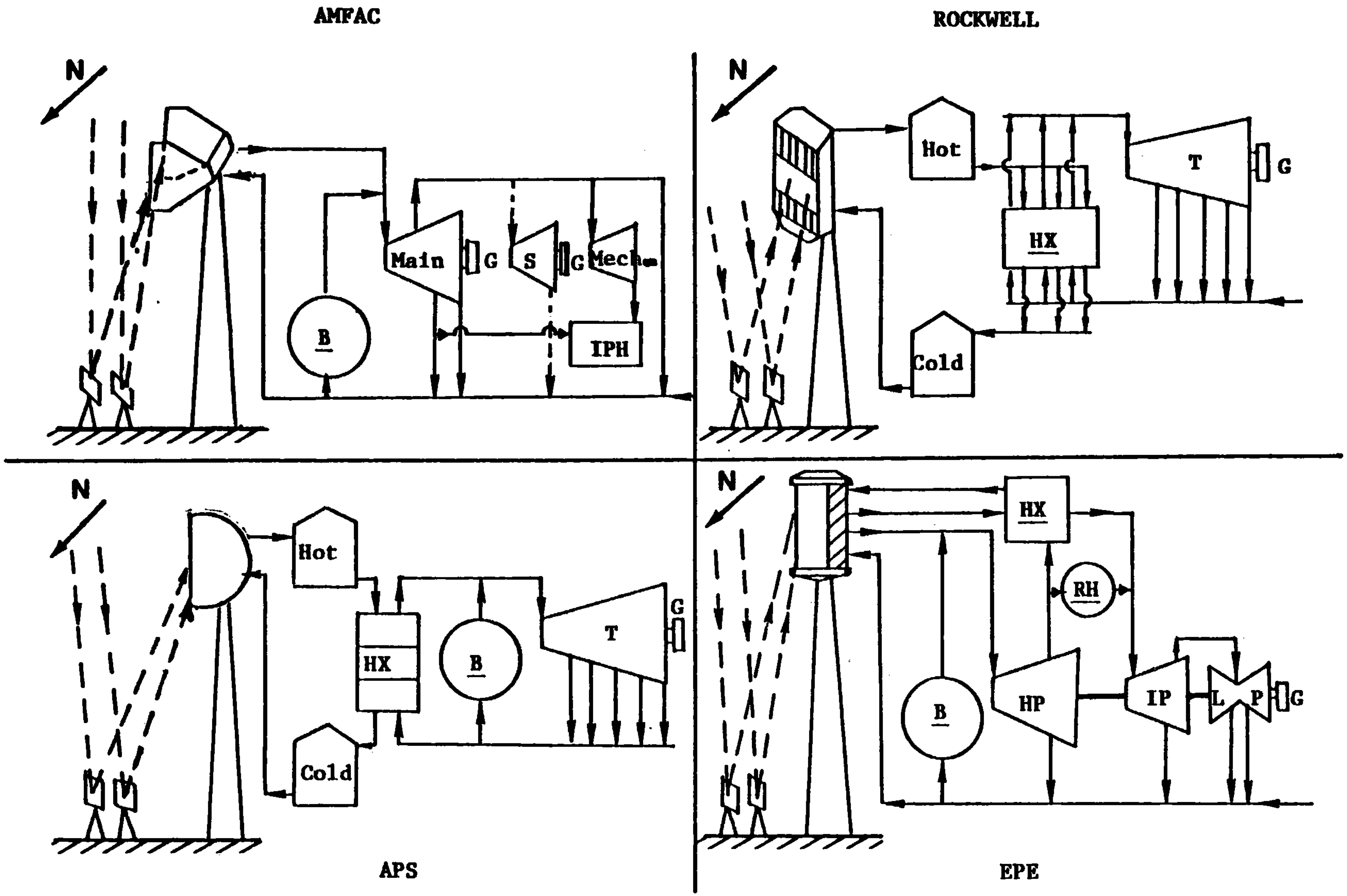


Figure 2-1. Schematic Flow Diagrams of Four Repowering Designs

requirements and shaft energy by the 2.4 MWm mechanical drive turbines. Low pressure extraction at 135°C/0.2 MPa is used to supply the remainder-of-the-mill steam requirements. During the off-season period, the main turbine output is increased along with the use of the small turbine and both IPH and mechanical drive operations are eliminated. Thus the Amfac facility operation is quite complex and solar generated steam conditions are degraded to match the current requirements of the mill's operations.

In the Rockwell design, the solar energy is used to heat liquid sodium pumped from a ground level cold storage tank from 321°C(610°F) to 566°C(1050°F). The heated sodium is drained by gravity to a hot storage tank and is pumped through steam generators and returns to the cold storage tank. The three once-through-to-superheat steam generators are connected in parallel to deliver 34 kg/s(270,000lb/hr) of steam to a turbine that has 5 extraction points for feedwater heating. The incorporation of on-line thermal storage permits the solar portion of the plant to start and operate independently from the electric power generation portion. The power conversion system is a non-reheat system requiring daily startup. The turbine unit is expected to operate at full load (30 MWe), however it is capable of part load operation down to 20 percent of generating capacity.

For the APS design, molten salt from the cold storage is pumped at 277°C (530°F) by cold salt pumps to the receiver where it is heated to 566°C (1050°F). The solar steam generator transfers energy from the molten salt to water-steam using a forced recirculation system having separate preheater, evaporator and superheater. The solar steam generator is designed to produce steam at 538°C/10.1 MPa when supplied with feedwater at 197°C. The interface between the solar and fossil systems are configured so that fossil can be used alone, solar used alone, or the two systems can generate the same quality steam with solar output of 89 to 172 MWt. The lower limit corresponds to produce a turbine gross output of 30 MWe, which is also the minimum rating of the fossil boiler. The current APS plant operates in an area protection mode, where unit-1 is operated at

40 MWe net for most of its operating hours. The plant is capable of load following with average capacity factor of 25.8% that corresponds to maximum gross output of 121 MWe. The existing fossil steam generator can be fired with natural gas, No. 6 oil, or combination of the two. The existing turbine-unit is a non-reheat system and has five feedwater heaters in service.

The EPE Newman Unit-1 is currently an intermediate plant with a 40 percent capacity factor and it generates a maximum plant gross output of 86 MWe (actual). The solar repowered plant could be operated in fossil mode, solar mode (4 to 42 MWe), solar with fossil backup (6 to 42 MWe), or solar with fossil in a load following mode (50 to 82 MWe). The fossil boiler is designed to use natural gas with oil as an alternate fuel source. The EPE design is based upon a water-steam central receiver technology that provides main steam ($538^{o}C/10.1MPa$) to the high pressure turbine section, and reheat steam ($532^{o}C/1.5MPa$) to the intermediate section of the existing turbine-generator.

Further specific details of the four SCR repowering designs and specifications are given below.

2.4 Amfac Design

The Amfac SCR design is sized to provide up to 57% (31.6 MWt) of the required steam during the weekday grinding season. During this time the sugar factory operates in a cogeneration mode for 35 weeks with 14 consecutive 8-hour shifts per week. During the weekends and off-season (190-days), the proposed facility will produce only electric power, most of which would be sold to the Maui Electric Company.

The collector subsystem consists of an optimized layout of 568 ARCO Solar Industries third generation heliostats on individual pipe and concrete caisson foundations, control and power wiring, and a beam characterization system. The heliostats with packing density of 0.23 are arranged on a radial stagger pattern of 21 concentric rows in a 150^{o}

field. The heliostats are controlled through an open-loop control system with seven operating modes. The collector field is divided into 12 sectors, each of which has an assigned aim point on the receiver aperture plane. Details of technical specifications of various subsystems are given in Table 2-3.

The receiver subsystem design is a north-facing side-by-side, twin-cavity, natural-circulation, steam generator with separate superheat circuitry. The two cavities are separated by north-south partition walls and the centerline of each cavity is angled 37.5^{o} from its partition wall. Six superheater panels are located in the forward portion of the two partition walls. The remaining portion of the partition walls, the rear walls, and the side walls are lined with boiler panels. All boiler and superheater panels are made of vertical tangent tubes with tie-backs at different elevations. Carbon steel tubes were selected for the boiler panels. Incoloy tubes were chosen for the two superheater panels located at the high heat flux zones and stainless steel tubes were chosen for the remaining four panels.

The boiler circuitry consists of a horizontal steam drum, 4 downcomers, 20 feeders, 8 boiler panels with headers, and 40 risers. The superheater consists of six vertical passes in series, three in the east cavity and three in the west. All steam flows are from the bottom of the tube to the top and are transferred between cavities to ensure uniform heating. A spray attemperator is used between passes 3 and 4 for steam temperature control. The receiver is sized to produce an output of 31.9 MWt. The tower, constructed of reinforced concrete, is 70.4 m high and 19.3 m in diameter at the base tapering to 18.0 m at the top with 0.25 m thick walls.

The thermal transport subsystem includes the steam and condensate pipes between the receiver and the mill, a condensate holding tank, condensate transfer pumps, a condensate demineralizer, a receiver deaerator, receiver feedwater pumps, a steam mixing station, and an uninterruptible power supply. Figure 2-2 gives the schematic flow diagram

Table 2-3

Amfac Pioneer Mill Summary of Solar Subsystems

<u>Collector Subsystem</u>	
Number of heliostats	568 (ARCO "third-generation")
Mirror area per heliostat	95.1 m^2 (16 modules)
Configuration	Dual axis tracking pedestal drive mount
Drive motors	Two 1/4 hp dc motors
Control	Single computer
<u>Receiver Subsystem</u>	
Maximum flux	0.7 MWt/m^2
Aperture midplane elevation	79 m
Receiver aperture, each twin	7.3 m wide and 7.6 m high
Number of superheater panels	6
Number of tubes/superheater panel	38 for 4 panels 47 for 2 high flux panels
Tube diameter, wall	22.2 mm, 2.1 mm
Tube material	Type 316H stainless steel for 4 panels Incoloy 800 for 2 high flux panels
Incident/absorbed power	37.4 MWt/31.9 MWt
<u>Steam Generation Subsystem</u>	
Steam outlet conditions	456 ^oC/ 9.24 MPa/40,370 kg/hr
Feedwater inlet conditions	113 ^oC/10.3 MPa/40,820 kg/hr
Steam Pipeline length	1190 m
Steam pipe diameter, insulation	13 cm, 115 mm
Electric steam superheater	770 kWt
Steam delivery conditions to mill	399 ^oC/5.97 MPa
Steam to receiver drum (overnight shutdown)	275 ^oC/5.97 MPa

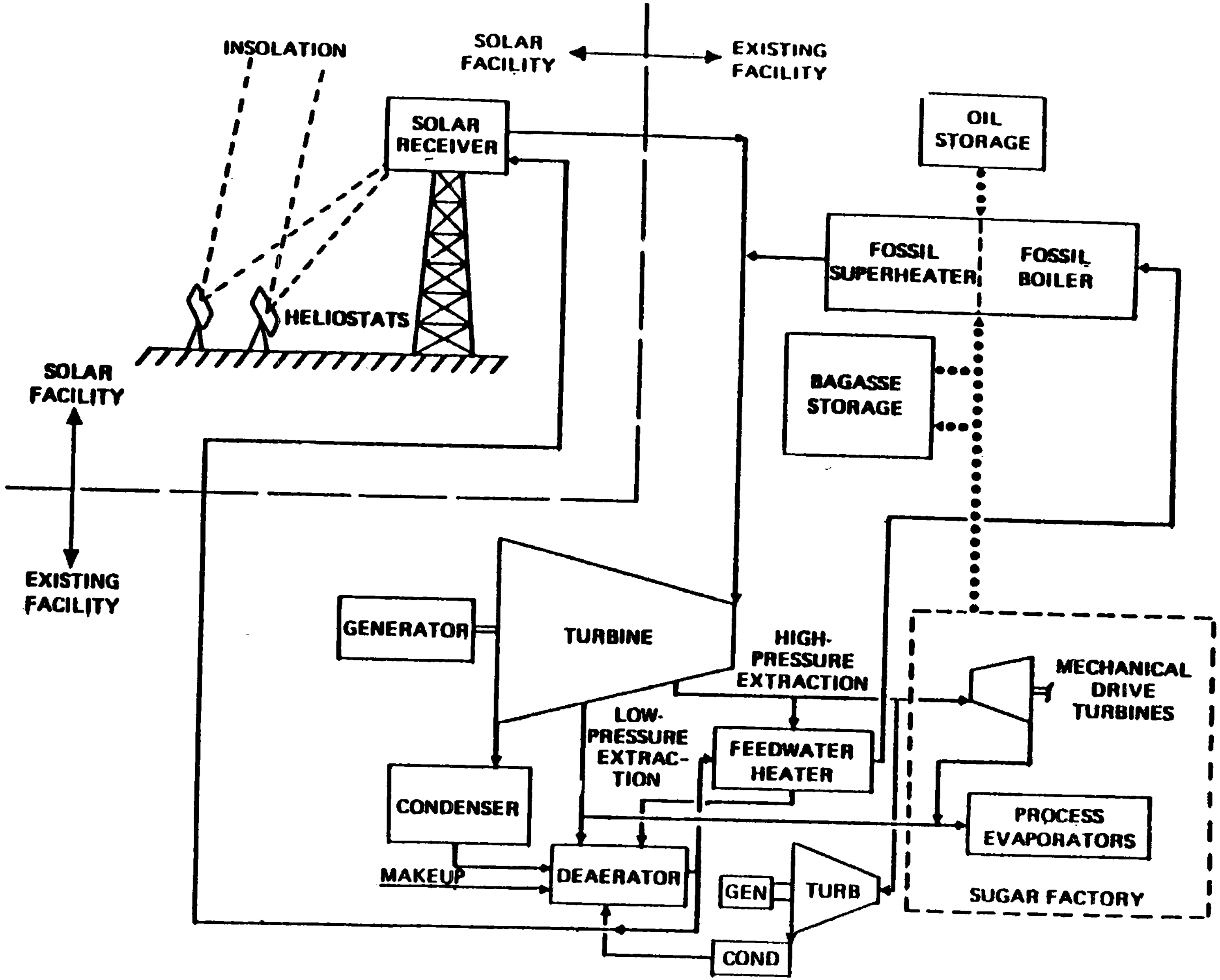


Figure 2-2. Amfac Pioneer Mill Repowered Cogeneration Plant Flow Diagram

of the Amfac repowering design. The steam mixing station consists of an electrical superheater, pressure reducing valves, and attemperators. The thermal transport steam piping is 13 cm in diameter and 1190 m long. To minimize the morning startup time of the solar facility and to reduce the diurnal thermal cycling of the receiver and the steam pipeline, the receiver and the steam pipeline are maintained at $275^{o}C/5.97MPa$ saturation conditions by fossil boilers during overnight and solar shutdowns. Low alloy steel is used for the steam pipe and carbon steel is used for the condensate pipe. A 300 kVA uninterruptible power supply, consisting of storage batteries and an inverter is located at the base of the tower.

The electric power generation subsystem consists of the two existing turbine-generators. The main unit is a General Electric double automatic extracting-condensing turbine generator rated at 9375 kVA, with design steam inlet conditions of $399^{o}C/5.96$ MPa . The other secondary unit is an Allis Chalmers single automatic extracting-condensing turbine generator. The solar receiver generates superheated steam at $456^{o}C/9.24$ MPa, and after thermal transport to the mill end of the pipe the steam conditions are $427^{o}C/5.97MPa$. An attemperator is used to attain the main turbine inlet temperature conditions of $399^{o}C$ by adding 870 kg/hr of boiler feedwater.

The master control subsystem controls the SCR operation and integrates the operation of the solar and non-solar operations of the mill's existing facilities. The major subsystem components are the control units for collector, receiver and the thermal transport subsystem, two operator consoles, a fiber optic communication loop between the collector, receiver, and thermal transport subsystem control units, and a data acquisition system. Automatic startup and various other sequences are programmed into the thermal transport subsystem controls.

2.5 Rockwell Design

The Rockwell solar plant design is a stand-alone 30 MWe power plant using liquid sodium as the receiver heat transfer and energy storage fluid. The site for the potential Rockwell plant is located in the Pacific Gas and Electric Company (PG&E) service territory at Carrisa Plains, San Luis Obispo County, California.

The plant uses a north-facing vertical flat-panel ("billboard") solar receiver that is supported by a steel truss tower at the south side of the 90° sector heliostat field. The receiver intercepts the solar energy redirected from 1877 "third-generation" ARCO heliostats. Each heliostat has 95.1 m^2 of reflective area that is divided into 16 mirror modules. The heliostat module support structure is composed of open-web beams connected to a horizontal tubular axis and drive unit. The entire heliostat is mounted on a pedestal and foundation, which is planted in an augered hole and grouted in place. The drive unit, which is computer controlled orients the heliostat continuously to track the sun and reflect the sunlight on the receiver. Initial heliostat aiming is aligned by reflecting a spot to a special panel (beam characterization system) located on the tower. The heliostat rate of motion is 11°/min (22°/min for reflected beam). In an emergency, the reflected energy can be removed from the receiver in less than 20 seconds. Further details of the collector and other subsystems are given in Table 2-4.

The receiver system consists of eight panels and each panel consists of 102 stainless steel (type 316) tubes (Table 2-4). The inlet piping to each panel has a flow control valve and a flow meter. Each panel has a flow control system that senses panel flux as a feed forward signal to control flow rate and also senses panel outlet temperature as a trim signal to control the outlet temperature to the set point. In the event that coolant flow is lost, an accumulator tank supplies cooling flow until the beam is off the receiver. The solar energy heats liquid sodium flowing through the receiver tubes. The cold ($321^{\circ}C/610^{\circ}F$) sodium is pumped to the

Table 2-4
Rockwell Design Summary of Solar Subsystems

<u>Collector Subsystem</u>	
Number of heliostats	1877 (ARCO "third generation") (for design details see Table 2-3)
<u>Receiver Subsystem</u>	
Maximum flux	1.2 MWt/m^2
Maximum power design	18.0 MWt/panel, 8 panels
Aperture midplane elevation	125m
Receiver aperture	16m wide, 12m high
Panel size	2.0m wide, 15.2m high
Number of tubes/panel	102
Tube diameter, wall	19.1 mm, 1.24 mm
Tube material	Type 316 stainless steel
Incident/absorbed power	118 MWt/107 MWt
Sodium Inlet/outlet temperature	321^{o}C(610^{o}F)/566^{o}C (1050^{o}F)
Cold sodium pump flow/head	0.39 m^3/s(6200 gpm)/198 m (650 ft)
<u>Steam Generation Subsystem</u>	
Number of units	3 (28.3 MWt each)
Diameter/length	0.45 m/21.1 m
Number of tubes per unit	158
Heat transfer area per unit	139 m
Steam flow per unit	11.32 kg/s (89,820 lb/h)
Pressure/temperature	10.1 MPa (1465 psia)/538 ^{o}C (1000 ^{o}F)
Feedwater temperature	224 ^{o}C (436 ^{o}F)
Hot sodium pump flow/head	0.33 m^3/s (5300 gpm)/58 m (190 ft)

the receiver by conventional sodium pumps from an atmospheric pressure, "cold" storage tank with argon cover gas located at ground level. As the sodium passes through the receiver tubes it heats to 566°C(1050°F). The heated sodium then drains by gravity to a "hot" storage tank, also located at ground level. From the hot storage tank it is pumped through the steam generators, cools to 321° C, and returns to the cold storage tank. The storage tanks (each 12.1 m diameter, 16.5 m height) have electric heaters for preheating and maintaining temperatures as required. The solar plant schematic flow diagram is given in Figure 2-3. Two pumps are used in each location of hot and cold storage tank to provide 20% design margin and redundancy to 70% of operating flow for coolant circulation.

Three once-through-to-superheat steam generators are connected in parallel to deliver 538°C(1000°F) and 10.1MPa(1465psia) steam to the turbine, which generates 32.7 MWe (gross). The three parallel steam generator units provide redundancy to 90% of full power with one unit out of service. The turbine is a two-section, single-shell machine with five extraction points. The main generator is designed to produce 12 kV, 3-phase, 60 Hz power. It is connected through a generator breaker to the main step-up transformer which raises the voltage to 115 kV. The incorporation of on-line thermal storage permits the solar portion of the plant to start up and operate independently from the electric power generation portion of the plant and also moderates cloud and other thermal transients, thus simplifying some of the control functions.

2.6 Arizona Public Service Design

The Arizona Public Service (APS) plant design repowers Unit One of the Saguaro oil/gas fired power plant to produce a gross electric output of 66 MWe and uses molten salt for heat transfer and the energy storage fluid. The collector system comprises 4,850 Martin Marietta improved "second-generation" heliostats that are divided into 10 canting zones (150° sector) to reduce spillage at the north-facing receiver aperture, and are aimed at six points in the aperture plane. Each heliostat incorporates 12 full-sized and one half-size focused and individually canted

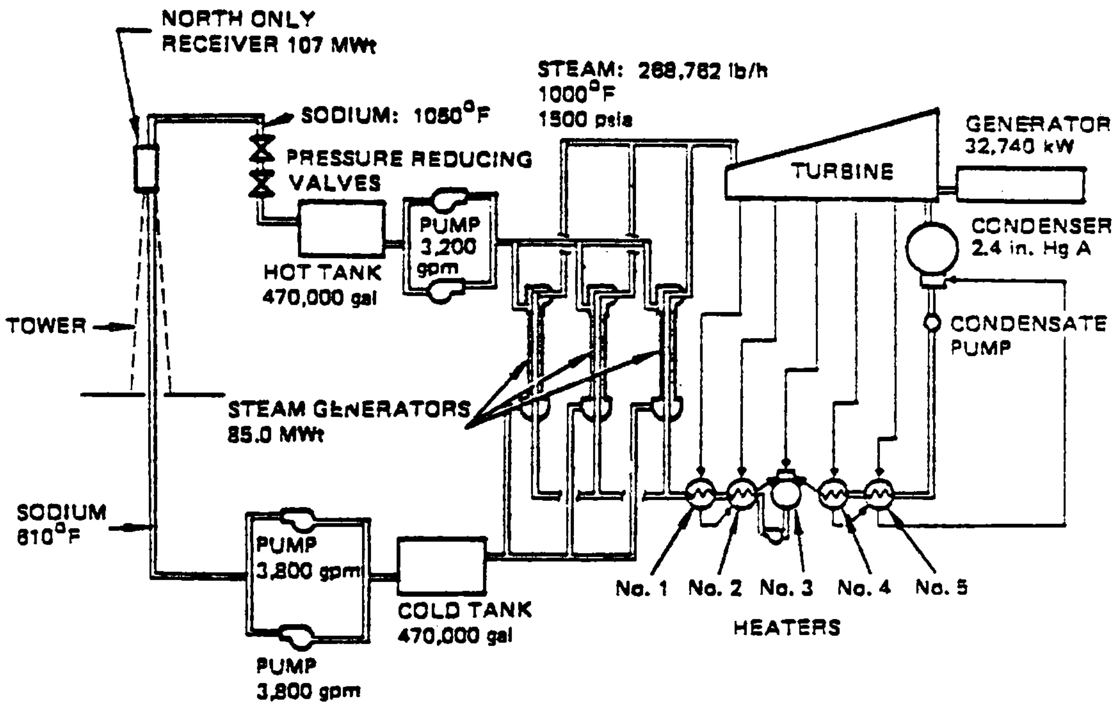


Figure 2-3. Rockwell Carrisa Plains Stand Alone Solar Plant

mirror assemblies that are mounted on a rigid, lightweight rack assembly structure. The heliostat uses second-surface silvered mirrors laminated to a float glass backing panel. The mirror assemblies are arranged to allow each heliostat to be positioned in a mirror-face-down stow position. Further details of the various subsystem specifications are given in Table 2-5.

The receiver system is a single, C-shaped cavity receiver where the energy absorbing surfaces are divided into 12 panels and each panel has an up and a down flow circuit with 42 tubes per circuit. The 277^{o}C(530^{o}F) molten salt (60% $NaNo_3$, 40% KNO_3, by weight) heat transfer fluid enters the receiver at the cold salt surge tank, then after splitting into two control zones, it passes through six panels in each zone in a serpentine flow path where it is heated to 566^{o}C(1050^{o}F). The heated salt from each zone goes to the hot surge tank, then proceeds through the downcomer to the hot salt storage tank. The receiver has a split door that can be closed to reduce thermal losses when the receiver is not operating. The outside face of the door is used as a beam characterization target.

The thermal energy storage system has a capacity of 688 MWht, which can provide energy up to four hours of full-capacity turbine operation. This storage system effectively decouples the energy collection system from the turbine operation which does not see the immediate effect of cloud cover. Figure 2-4 gives a schematic flow diagram of the APS repowered solar plant design. Both the cold and hot salt storage tanks are made of carbon steel to the same general requirements with the exception of hot salt tank requiring thicker external insulation and a special, thin, incoloy 800 liner of waffle-like configuration to keep the hot salt from contacting the internal insulation.

The solar steam generator transfers energy from the molten salt to water-steam using a forced once-through recirculation system utilizing three U-tube, U-shell salt-steam heat exchangers (preheater, evaporator and

Table 2-5

APS Design Summary of Solar Subsystems

<u>Collector Subsystem</u>	
Number of heliostats	4,850 (Martin Marietta "second generation")
Mirror area per heliostat	$58.53 m^2$ (12 1/2 individually canted modules)
Configuration	Two axis tracking pedestal drive mount
Drive motors	Two-speed dc motors for each axis
Control	Distributed digital control
<u>Receiver Subsystem</u>	
Maximum flux	$0.529\ MWt/m^2$
Aperture midplane elevation	155.2 m
Receiver aperture	18.3 m wide, 18.3 m high
Number of panels	12
Panel size	3.2 m wide, 22.9 m high
Number of tubes/panel	84
Tube diameter, wall	38 mm, 1.65 mm
Tube material	Incoloy 800 with black Pyromark-2500 paint
Incident/absorbed power	211 MWt/190 MWt
Inlet/outlet salt temperature	$277^{o}C$ ($530^{o}F$)/$566^{o}C$ ($1050^{o}F$)
Cold salt pump flow/head	429.2 kg/s (3.406×10^{6} lb/hr)/487m (1600ft)
Salt Pipeline length	1340 m
<u>Steam Generation Subsystem</u>	
Number of units	1 (172.5 MWt)
Steam flow (superheater, evaporation)	65.6 kg/s, 99.4 kg/s
Pressure/temperature	10.0 MPa/$538^{o}C$
Feedwater temperature	$197^{o}C$
Molten salt flow (super-heater, evaporation)	401.5 kg/s, 455.0 kg/s
Inlet salt pressure	1.31 MPa
Hot salt pump flow/head	389.7kg/s(3.093×10^{6} lb/hr)/107m (350 ft)

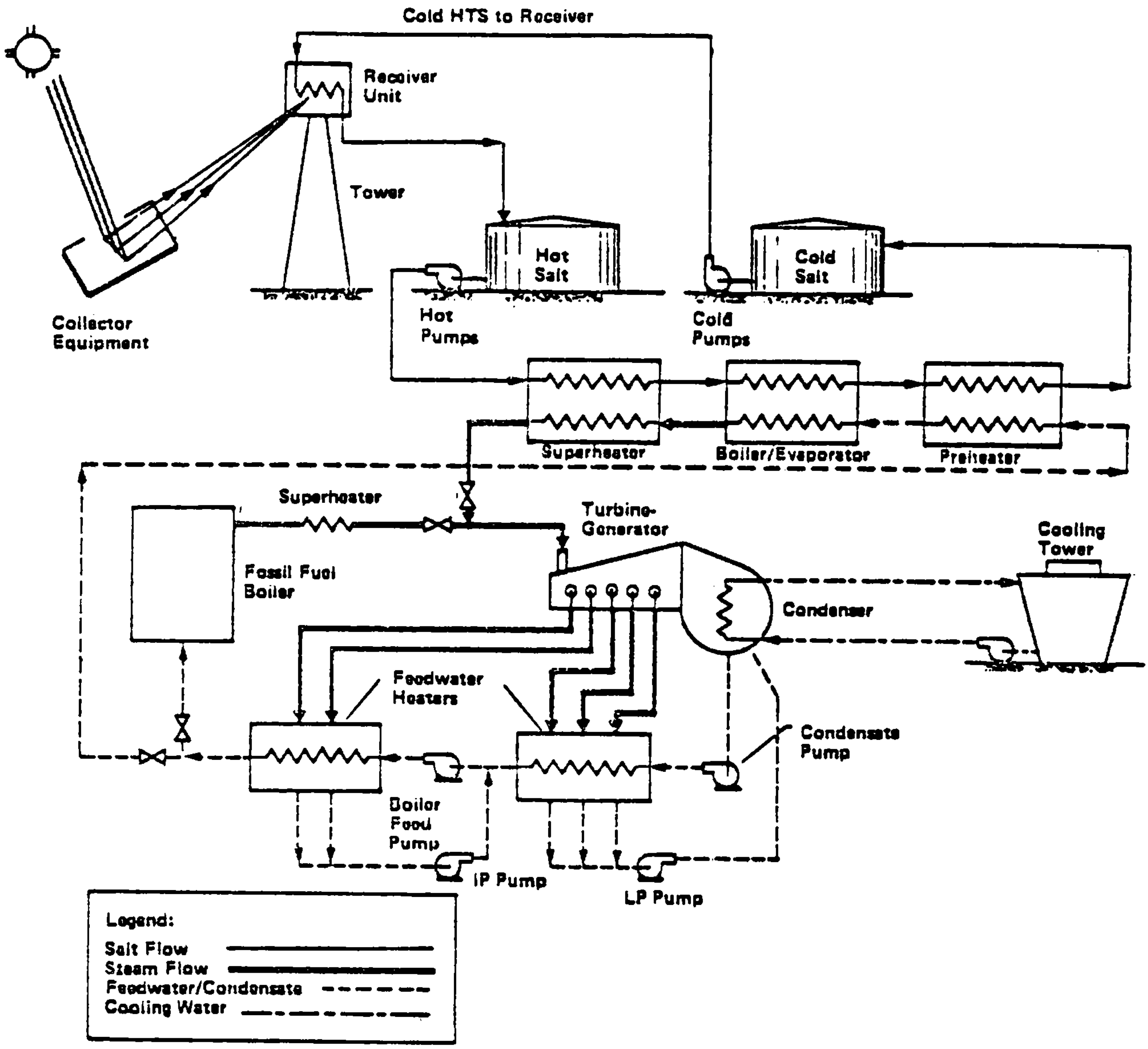


Figure 2-4. APS Repowered Solar Plant Flow Diagram

superheater) to the cold salt storage tank. The superheater hot salt inlet temperature is controlled by mixing it with cold salt and likewise the evaporator salt inlet temperature is controlled by mixing cold salt with the salt exiting the superheater. After exiting the evaporator, the cold salt is circulated through the preheater and then returned to the cold salt storage tank. Feedwater from the high-pressure feedwater is mixed with saturated water from the steam drum to increase the feedwater temperature entering the preheater. Feedwater is preheated to near-saturation temperature and delivered to the steam drum. In the drum, the feedwater is mixed with recirculated water and pumped to the evaporator where a high-quality mixture of steam and water is produced. The steam and water mixture is returned to the drum where the steam and water phases are separated. The saturated steam is then superheated and sent to the turbine. The solar steam generator is designed to generate superheated steam at 10.0MPa(1450psia) and $538^{\circ}C(1000^{\circ}F)$ at a maximum power level of 172.5 MWt when supplied with feedwater at $197^{\circ}C(387^{\circ}F)$ from high-pressure feedwater preheater.

2.7 El Paso Electric Design

El Paso Electric Company's (EPE) preliminary design repowers the existing oil/gas fired Newman Unit-1 that has an 80 MWe (net) tandem-compound, double-flow, reheat steam turbine. The EPE preliminary design selected a 50 percent solar fraction (41 MWe at noon winter solstice). The heat transfer fluid is water/steam. There is no separate energy storage subsystem. Further details of the various subsystem specifications are given as Table 2-6.

The collector subsystem consists of a north field in a 160° sector array of 1875 generic third generation heliostats, each having a glass reflective surface area of $95m^2(1023ft^2)$ and includes two percent redundant heliostats to provide for heliostat outages and degradation.

Table 2-6

El Paso Electric Summary of Solar Subsystems

<u>Collector Subsystem</u>	
Number of heliostats	1,875 (generic "third generation")
Mirror area per heliostat	95 m^2
<u>Receiver Subsystem</u>	
Maximum flux	0.66 MW/m^2
Aperture midplane elevation	155 m
Number of absorber modules	18 (14 preheater & 4 superheater modules)
Absorber height, width	25.9 m (85 ft), 18.0 m (59 ft)
Receiver absorbing surface	811.4 m^2 (8734 ft)
Incident/absorbed power	127 MWt/111 MWt
<u>Steam Generation Subsystem</u>	
Primary superheater steam conditions	118,000 kg/hr (261,900 lb/hr) 12.45 MPa (1,806 psia) 549^{o}C (1,020^{o}F)
Final superheater steam conditions	130,500 kg/hr (287,600 lb/hr) 10.41 MPa (1510 psia) 540.5^{o}C (1005^{o}F)
High pressure turbine inlet	130,500b kg/hr (287,600 lb/hr) 10.1 MPa (1,465 psia) 538^{o}C (1000^{o}F)
Intermediate turbine inlet	119,500 kg/hr (263,400 lb/hr) 1.52 PMa (220 psia) 532^{o}C (990^{o}F)

The EPE receiver is an external cylinder panel type configuration with a forced recirculation boiler system. The receiver subsystem consists of a water-steam cooled drum-type design which intercepts the radiant flux reflected from the collector subsystem, a concrete tower, a reheat heat exchanger and associated feedwater and steam piping. The receiver is essentially a steam generator consisting of a preheater, evaporator, primary superheater and final superheater, operating at various temperature levels. The receiver consists of a total of 18 preheater and superheater absorber modules containing narrow interlaced membrane wall panels at the periphery of a vertical absorber cylinder.

The preheater modules are of the membrane wall construction. The 48 carbon steel tubes of each module are disposed vertically for upflow of feedwater, and each tube is connected to a common inlet header at the bottom and to a common outlet header at the top. The superheater modules consist of one superheater panel flanked on each side by narrow evaporator panels. Each superheater panel contains 26 (or 29) Incoloy 800H 28.5 mm diameter tubes welded together along their entire length. The evaporator panels are also of membrane construction and contains eight 38.1 mm OD carbon steel ribbed tubes on 50.8 mm centerlines. The primary superheater is divided into three separate flow passes and the final superheater has two passes.

The high pressure, high temperature superheated steam at $549^{\circ}C$ generated in the receiver is used in a heat exchanger located near the turbine to reheat the steam leaving the HP turbine at $373^{\circ}C$ to the desired temperature of about $532^{\circ}C$ before admission into the IP turbine. The cooled high pressure steam at $425^{\circ}C$ leaving the heat exchanger is then returned to the receiver for final superheating and delivered at desired temperature of $538^{\circ}C$ to the HP turbine. Figure 2-5 gives the schematic flow diagram of the EPE solar repowering design for the Newman Unit-1 plant.

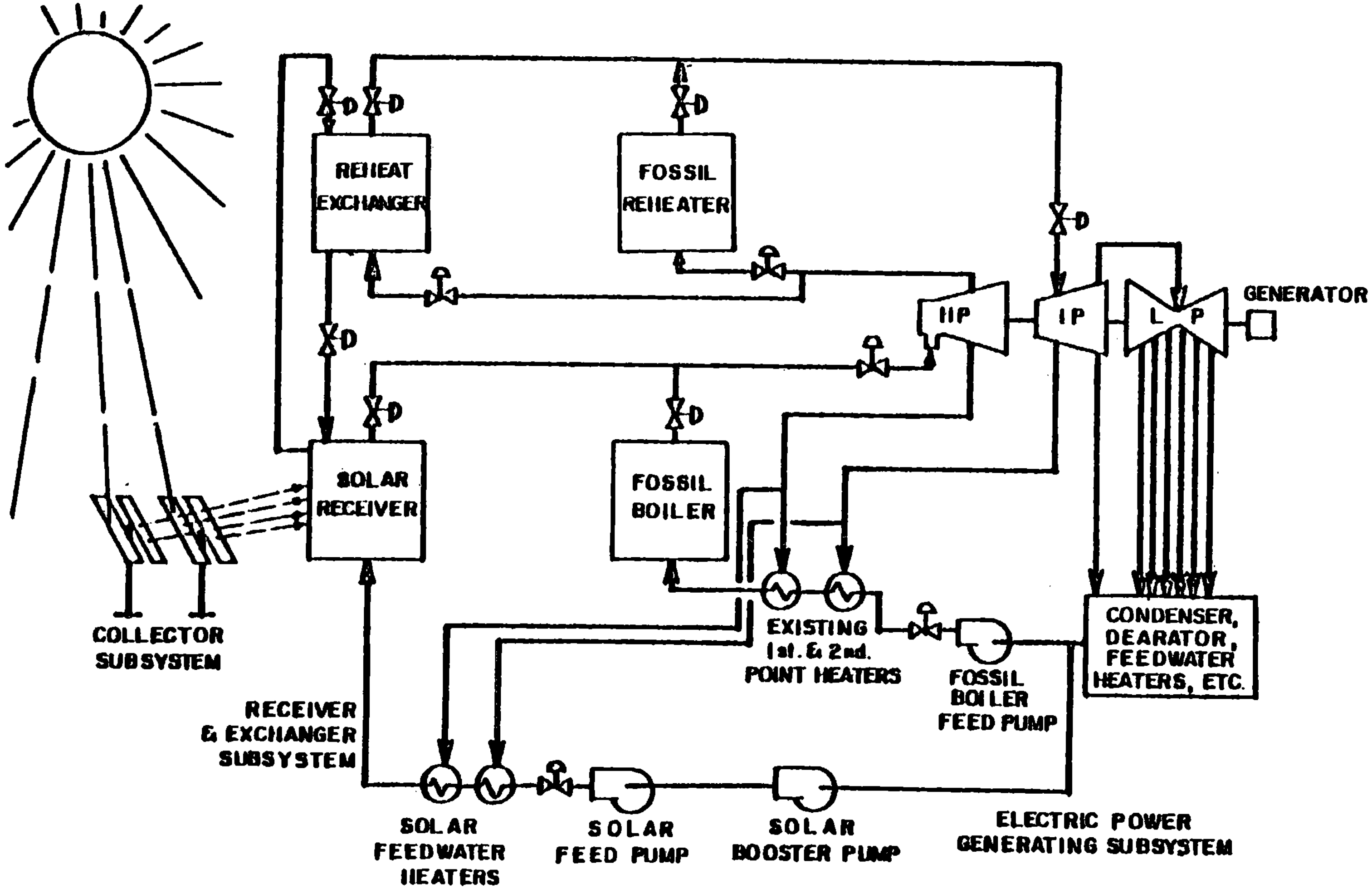


Figure 2-5. El Paso Electric Newman Unit-1 Repowered Solar Plant Flow Diagram

Steam generated by the solar receiver is mixed with the steam provided by the existing fossil steam generator before admission to the high pressure and intermediate pressure section of the turbine. Attemperation of the fossil and solar generated steam ensures that steam temperatures are maintained within turbine design limits. The feedwater supply to solar and fossil steam generators matches the steam flow and their individual pressure requirements by means of a coordinated control system.

The control system consists of a distributed microprocessor based system that includes receiver control, heliostat field control and modification of existing turbine generator and boiler controls. Each group of about 22 heliostats is controlled by a heliostat field controller and the entire field is controlled by the heliostat array controller which also contains several activity sequences involving startup, tracking, emergency defocus and shutdown.

3.0 COMPARISONS OF SUBSYSTEMS AND PLANT PERFORMANCE

3.1 Comparisons of Subsystem Performance

Solar plant performance data developed by the four repowering design teams included both design point and annual average performance. The design point performance referred to noon time on some specified day at certain level of available insolation. The annual average performance data are more useful for solar plant evaluations as these determine the amount of both plants' annual energy production and revenue streams. Table 3-1 summarizes the design point and annual average subsystem performance efficiencies for the four SCR designs. These efficiencies were derived from the repowering design teams published data on stairstep efficiencies, subsystem performance, and energy production. A performance efficiency of N % for a given subsystem item in Table 3-1 represents a (1-N)% loss due to that item.

The performance efficiencies for collector subsystem in Table 3-1 are based upon various geometric and optical losses and were derived by the contractors with the help of different computer codes. These collector subsystem efficiencies include the losses due to heliostat reliability, cosine and shading, reflectivity, blocking, atmospheric attenuation and aperture spillage. The receiver subsystem efficiencies include the losses due to receiver reflectivity, reradiation, convection and conduction losses. Solar steam generation subsystem efficiency includes both thermal gain from the pumps, and loss from the pipes and heat exchangers. The efficiency for operating load is based upon the various parasitic losses involving auxiliary and standby power and steam requirements for various subsystems of power conversion, heat transport, collector field, receiver subsystem etc. Losses due to storage subsystem and transient periods (morning, evening and cloudy days) are also included in the operating load values of Table 3-1. Plant availability efficiency is based upon the losses due to scheduled maintenance and forced outages.

Table 3-1

Design Point and Annual Average Subsystem Performance Efficiencies

	Amfac		Rockwell		APS		EPE	
	Design	Annual	Design	Annual	Design	Annual	Design	Annual
Overall Collector System	69.6%	61.0%	67.4%	54.9%	77.5%	65.8%(↓)	75.4%	62.1%
Collector Reliability	99.0	99.0	100.0	99.1	99.7	99.7	98.0	98.0
Cosine & Shading	87.0	78.8	90.4	80.0	93.6	80.3	92.6	79.8
Reflectivity	88.0	86.9(!)	83.4	83.4	92.0	92.0(↓)	90.0	86.0
Blocking	99.6	99.6	98.7	94.4(!)	99.8	99.3	98.5	98.6
Attenuation	96.5	96.2	94.4	93.5	93.1	92.7	94.0	93.9
Spillage	95.5	93.9	96.0	94.0	97.2	97.0	99.7	99.7
Overall Receiver System	89.3	87.2(↑)	90.7	89.5	91.1	88.3(↑↓)	83.2	75.4(!)
Reflectivity	95.8	95.8(↑)	95.0	95.0	98.0	98.0	95.0	95.0
Thermal Losses	93.2	91.0	95.5	94.2	93.0	90.1	87.6	79.5(!)
Solar Steam Generation	99.2	98.6	101.6	101.6	101.1	99.9	99.0	99.5
Electricity Generation	30.0(!)	23.0(!)	38.5	38.5	38.5	38.5	41.7	39.8
Operating Load	87.0	78.0(!)	90.8	89.1(↓)	87.9	82.6	91.8	84.0
Plant Availability		93.9	-	93.1	-	91.1	-	88.3(↑)

(↓ or ↑) Suspect Result

(!) Meaningful Difference

A. Collector Subsystem Performance

All of the design teams assumed a relatively good rating for their collector reliability, except for the EPE team that assumed a 2% collector outage rate. Collector annual cosine and shading losses that are a function of both solar elevation and azimuth angles were about 20% for all the proposed solar facilities. The shading losses include both tower shading and adjacent heliostat shadows and these losses reduce the useful heliostat reflective area. There were, however, significant differences in the heliostat annual reflectivity values of the different contractors. These annual reflectivity values are a function of heliostat wash frequency, cleaning procedure, dust and wind environment, heliostat design, and downward slopes.

Both Amfac and Rockwell designs are based upon the use of ARCO third-generation heliostats that are second-surface silvered-glass mirror modules with mirror thickness of 1 mm laminated to 3.2 mm glass backing. The original "in-the-box" reflectivity of these heliostats is reported at 91%. The design of the APS plant is based upon Martin Marietta improved second-generation heliostats which are also second-surface silvered-mirrors laminated to a float glass backing with new reflectivity of 92%. The EPE generic heliostat design also assumed a 92% "in-the-box" reflectivity. For the design point performance, the EPE team assumed a 2% decrease in the original new reflectivity. This was assumed to further drop by an additional 4% for the annual average mirror reflectivity. The APS team, however, assumed its new mirror reflectivity value (92%) for both design point and annual average plant performance. The Rockwell design assumed a 6.7% drop in the original reflectivity for both the design point and annual average plant performance (Table 3-1). This reflectivity drop included a 3% loss due to dust.

The Amfac design team reported relatively well supported reflectivity values that were based upon 236-day on-site reflectivity measurements on ARCO second generation heliostats. The Amfac team used a portable reflectometer where measurements were made on the average of every 10 days.

These reflectivity measurements were shifted upwards to account for the improved reflectivity (91%) of ARCO third generation heliostats. For the Amfac design point, it was assumed that one wash would bring the mirror reflectivity back to within 3 percent of the original new mirror reflectivity (Table 3-1). These reflectivity measurements suggest that an annual reflectivity of 88% is possible with daily washing of heliostats and 87% is possible with a 19-day wash cycle. The Amfac team used the latter value for their annual heliostat mirror performance. The Rockwell estimate for the annual heliostat reflectivity is about 4% lower than the Amfac estimate for the same type of heliostat. This may partly be due to more mirror washing that is assumed by the Amfac team. This difference in the annual average reflectivity of the Amfac team is meaningful and well supported. This meaningful difference in the quality of the reported data has been pointed out in Table 3-1. Similarly, suspect data and results are also pointed out in Table 3-1. The APS 92% annual average reflectivity appears to be optimistic, as compared to the data of other design teams (average reflectivity 85.4%). Thus, as pointed out in Table 3-1, the annual average reflectivity for the APS design may be suspect. It was reported by the Amfac team that depending upon the surrounding environment, less favorable heliostat orientations in winter can cause an 0.8 to 0.9 percent reflectivity decrease per day.

Collector blocking losses are caused by the adjacent heliostats that prevent heliostat reflected beams from reaching the receiver aperture. Except for the Rockwell design, these losses were about one percent. The higher collector blocking losses for the Rockwell design may be meaningful due to the geometric layout of the Rockwell collector field (90^{o} sector, high packing density). The annual average optical losses due to attenuation were about 6 to 7 percent except for the Amfac design (< 4%) where the reflected beam has to travel a relatively short distance attributed to Amfac's relatively short shortest receiver elevation (79m). The optical losses due to aperture spillage are a function of sun position, aperture shape and size, heliostat size and beam quality, aperture aim points and aiming errors. The higher spillage losses (~6%) for the Amfac and Rockwell designs may be due to their aperture shapes (Section 2-3, 2-4) and relatively small aperture area.

The above performance efficiencies for the collector subsystem as reported in Table 3-1 represent different types of geometric and optical inefficiencies (losses) which when multiplied together would give overall collector system performance efficiency. Similarly, overall performance of other subsystems are determined by multiplying the separate performance efficiencies of the individual components of a given subsystem. Thus, an annual average collector efficiency of 61% is calculated for the Amfac design by multiplying its individual efficiencies due to reliability, cosine and shading, reflectivity, etc. This collector efficiency of 61% represents that out of the available solar insolation, only 61% reaches the receiver aperture as incident energy.

B. Receiver Subsystem Performance

The overall efficiency of a receiver is defined as the ratio of the total energy retained by the working fluid to the total energy entering the aperture. The total energy retained by the working fluid is equivalent to the total energy entering the aperture minus the losses involving reflection, reradiation, convection and conduction. The reflection losses are primarily due to the energy absorbing surfaces being not absolutely black. The Amfac team assumed that 10% of the incident light was reflected (absorptivity 0.9) to either the aperture or another absorbing surface of their twin cavity receiver design. Based upon this assumption and their cavity design, a reflection loss of 4.2% was calculated by the Amfac team (Table 3-1). Both the Rockwell and the EPE teams assumed a net absorptivity of 0.95 for their external receivers. The APS team estimated a net receiver absorptivity of 0.98 by assuming receiver panels absorptivity of 0.95. Thus, compared to the APS and other designs, the Amfac receiver panel absorptivity of 0.90 appears to be conservative. Thus, the Amfac receiver reflectivity losses may be somewhat lower than the reported values, especially if they were also to use the same black paint material (Pyromark-2500) on the panel (tubes) surfaces.

The receiver thermal losses by the Amfac team were determined with the help of cavity heated surface temperatures. For the Amfac design point conditions, the reradiation, convection and conduction losses were found to be 1.7%, 4.9% and 0.3%, respectively. These design point thermal losses (6.8%) increased with decreasing loads and were estimated to be 9% for the annual average load conditions. The Rockwell receiver thermal losses were estimated at 5.8% for the annual load conditions. These lower thermal losses, in spite of the external receiver design, appear to be due to the compact design of the liquid sodium receiver and receiver operating mode wherein liquid sodium is drained to the storage system during overnight and cloudy days.

The annual receiver thermal losses for the APS molten salt cavity receiver were estimated at 9.9 percent. The APS overall receiver efficiency of 88.3% has a calculation uncertainty range with lower and upper efficiency limits of 86 to 93 percents. These APS thermal losses also include losses with molten-salt heat transport line that is 1340m (0.8 mi) long. The design point receiver thermal efficiency of the EPE external water-steam receiver was reported at 87.6% and is based upon reradiation (6.3%), convection (5%) and conduction (.5%) losses that amount to a total of 11.4% of the energy entering the aperture. The higher reradiation losses of the EPE water-steam receiver are due to external receiver configurations. These losses are significantly less for the Amfac water-steam twin-cavity receiver design. Thus, the high annual receiver thermal losses (20%) for the EPE reported design are meaningful (Table 3-1).

C. Solar Steam Generation

For the Amfac and EPE water-steam designs, the steam generation losses are due to heat loss in the steam and condensate pipes, and blowdown losses. It does not include the energy required to keep the steam at certain minimum conditions during overnight and cloudy days. These external energy requirements are included under operating loads. For the Amfac design, it includes the thermal losses in the steam transport line (1190 m) that links the sugar mill to the solar receiver. For the forced recirculating single phase liquid sodium (Rockwell) and molten-salt (APS) designs, the steam generation performance includes the heat gain due to pumping power. For example, the APS annual pumping thermal energy is about 1.3% of the receiver thermal output. The outside electric power used to operate the liquid sodium or molten salt pumps and electric heaters are included under operating loads.

D. Electricity Generation

Electric generation efficiencies in Table 3-1 represent the performance of a turbine-generator unit and correspond to gross power output. The difference in the gross and net power output due to generating parasitic loads are accounted for under operating load. The low power generation efficiencies for the Amfac design are meaningful. At the design point, the Amfac cogeneration system is assumed to operate only in the power generation mode for ease of comparison with the other designs. Here relatively lower grade steam ($399^{o}C/5.97$ MPa) is used in two separate small turbines (8.4 and 3.5 MWe). The lower design point power generation efficiency (Table 3-1) is due to both smaller size turbine and relatively lower grade steam that yields lower Carnot efficiency. The still lower annual average power generation efficiency is due to the cogeneration operating mode where power generation efficiency is compromised by extracting IPH steam ($260^{o}C/1.83$ MPa) from the main turbine unit. However, the cogeneration utilization efficiency is quite high for both the design point (85%) and annual average (66%) conditions.

The turbine inlet steam conditions for the other three designs were about the same (Table 2-2). The higher design electric generating efficiency for the EPE plant is due to the use of existing reheat turbine, that is reported to be capable of generating power 8% more efficiently (41.7% vs. 38.5%) compared to the Rockwell and APS design values. The drop in the design point to annual average efficiency value is due to lower annual average generating requirements (4 to 82 MWe) by the EPE system. A relatively constant power output was assumed by the Rockwell (30 MWe) and APS (40 MWe) designs.

E. Operating Load

The operating load efficiency is the net of all parasitic losses, including all auxiliary and standby electric and steam demands, electric and oil or natural gas heaters that are due to the solar facility and solar share of the common plant energy loads. The incremental annual auxiliary electric loads attributed to the Amfac solar facility is estimated at 1020 MWh/year. This is primarily due to feedwater pump, electric superheater and heliostat drives. Also as mentioned earlier (Section 2-3), both the receiver and steam pipeline are maintained at 5.97 MPa/275^{o}C by outside energy whenever the solar facility is not operating. The Amfac annual operating load efficiency in Table 3-1 also includes the above losses as well as energy lost (14.8%) in the morning and evenings when the solar insolation is below the 25% receiver design conditions (transient losses). The resulting low annual operating load efficiency for the Amfac plant is realistic due to the nature of the water-steam technology, absence of storage system and the way the solar facility is operated.

The Rockwell annual operating load efficiency of 89.1% is based upon an auxiliary power requirement at about 2.5 MWe that is primarily due to the power conversion and heat transport systems. In addition, the overnight heat transport system power requirements is 0.21 MWe. The plant storage system thermal loss is also included in the operating load. However, this storage thermal loss, that was reported to be negligible by Rockwell, appears to be rather optimistic. The reported annual load efficiency for the Rockwell plant is the highest among the various contractors' plant data. This high value, however, appears to be optimistic and is contrary to the general requirement of relatively higher auxiliary load requirements for a Carrisa Plains type solar stand alone plant. The APS operating load annual efficiency includes auxiliary energy use to maintain the solar facility (8.8%), and power purchases from the grid for the receiver (2%), and turbine (3%) subsystems. It also includes losses due to thermal storage efficiency of 96.5%. The EPE design point and annual parasitic losses were reported as 8.2% and 16%, respectively.

F. Plant Availability

The Amfac annual plant availability is based upon a forced outage of 5%, and an annual 2-week schedule outage in January. The Rockwell estimate of plant availability includes a 20-day scheduled outage in December that results in the loss of 78 full-power hours. In addition, the estimate includes forced outages (except for collector subsystem) of 120.4 hours out of an expected total of 3400 annual plant operating hours. Also, plant operations are assumed to commence when the direct insolation exceeds 150 W/m^2, which results in the loss of 1.1% of plant availability. The APS plant availability is based upon a forced outage rate of 5% and an additional scheduled outage for plant maintenance. This planned maintenance is assumed from January 4 to the 24th, in which 5.4 GWh (4.1%) are lost. The EPE plant availability is based upon a forced outage of 7% and a scheduled outage of 3 weeks every year. This 7% forced outage estimate for the EPE water-steam design is the highest among various design teams (5%) and appears to be rather conservative.

3.2 Comparisons of Overall Plant Performance

The design point and annual average insolation for the different plants are summarized in Table 3-2. As seen from Table 3-2, Amfac and Rockwell referred their design point performance to the spring equinox noon hour with an insolation level of 950 W/m^2. The design point performance for the APS team was calculated for day 35 with a noon insolation level of 950 W/m^2. EPE calculated its design performance at noon of the winter solstice and assumed insolation of 1000 W/m^2. The annual insolation data for the Amfac design was based upon data taken at the site over the period, November 1980 through October 1981 and appears to be most reliable as it corresponds to the actual site of the proposed solar facility. The insolation data for the Rockwell Carrisa Plains plant appears to be most uncertain as it is based upon an estimated three-station average of Fresno, Santa Maria, and China Lake. APS and EPE insolation data are based upon SOLMET Typical Meteorological Year (TMY) data tapes for Phoenix, Arizona and El Paso, Texas. However, the APS Suguaro Plant location is about 100 miles south of the Phoenix data site.

Table 3-2

Overall Plant System Performance Comparisons

	Amfac	Rockwell	APS	EPE
Site Insolation				
Annual Average (kWh/m^2)	2307 (!)	2524 (↑↓)	2519 (↓)	2650
Overall Electric Efficiency				
Design Point Net (%)	16.1 (!)	21.7	24.0	23.8
Annual Net (%)	8.5 (!)	15.9 (↓)	16.8 (15.9[a])	13.8 (↑)
Annual Energy Displaced	10.9 GWhe/11.5 GWht	75.6 GWhe(↓)	120.3 GWhe (↓)	65.2 GWhe(↑)
Performance of Solar Portion				
$\frac{MWh_t}{MWh_{insol}}$				
Design Point	0.62	0.62	0.71 (0.67[a])	0.62
Annual Average	0.45	0.50	0.56 (0.53[a])	0.47
Annual Solar Factor				
$\frac{MWh_t \text{ (Gross)}}{\text{Heliostat Area } (m^2)}$	1.03 (1.13[b])	1.27 (1.27[b])	1.41 (1.33[a])	1.24 (1.18[b])
$\frac{MWh_e \text{ (Net)}}{\text{Heliostat Area } (m^2)}$	0.20 (+0.21 thermal)	0.42 (↓)	0.42 (0.40[a])	0.37 (↑)

a Corrected for Arco Heliostat Reflectivity (Amfac)
b Adjusted to APS Insolation
(↑ or ↓) Suspect Results
(!) Meaningful Difference

Both the subsystem performance (Table 3-1) and overall plant performance given in Table 3-2 are based upon the above insolation data values.

A. Overall Electric Efficiency

The overall plant electric efficiencies as reported in Table 3-2 are determined by multiplying the individual subsystem (collector, receiver, electricity generation, operating load, etc.) efficiencies given in Table 3-1. Thus, any uncertainty or meaningful difference in any subsystem efficiency is also reflected in the quality of the overall plant efficiency. For example, the effect of the seemingly optimistic annual mirror reflectivity for the APS design would be carried through to the overall plant performance efficiency. If APS annual collector reflectivity were to be 87% instead of the reported 92%, the overall plant efficiencies of both APS and Rockwell design would be about 15.9%.

B. Annual Energy Displaced

The amounts of annual energy displacement are the most important performance values and represent the plant performance bottom lines. These annual energy displacement values determine the plant revenues and thus play a key role in the economic assessment of a solar plant. The annual net electric energy sold or displaced is determined from the product of the plants annual electric energy efficiency, collector area (Table 2-1) and annual insolation. Since the displaced annual electric power is the most important performance parameter, a calculation check was carried out for all the four plant designs. These independent calculations checked fairly well for all the designs, except for the Rockwell design, which resulted in a net power output of about 72 GWH/yr instead of the reported 75.6 GWH/yr. Thus, the reported net power output by the Rockwell team may be somewhat optimistic (5%) due to calculation discrepancy. As mentioned earlier, the APS net power output is optimistic due to the assumption of optimistic collector mirror reflectivity.

C. Performance of Solar Thermal Portion

The efficiencies of the solar thermal portions of each plant design assess the potential of different SCR technologies and receiver designs. These assessments, however, exclude the differences in the associated parasitic loads and plant maintenance losses that may be associated with different solar designs. However, the outside differences due to the existing facility power generation efficiencies are also excluded. The efficiencies of the solar thermal portion are given in Table 3-2 for both design point and annual average performance.

D. Annual Solar Factor

The annual solar factor, defined as the ratio of annual energy produced divided by the heliostat mirror area, is helpful in evaluating SCR performance with other solar technologies involving parabolic troughs and dishes. Table 3-2 gives such performance measures for both gross thermal energy and net electric energy. The ratio involving gross thermal energy is helpful in comparing with the other solar steam generating units (parabolic troughs). The ratio with net electric energy can be used to compare with other solar electric power generating units (dishes).

All of the above plant performance measures give the relative efficiencies of different solar systems and overlook the relative costs involved for each solar technology or plant design. Comparisons of these solar plant costs are reported in Section 4.

4.0 REVIEW AND COMPARISONS OF CAPITAL AND PROJECT COSTS

4.1 Level and Format of Cost Details

Capital cost estimates for the four SCR designs were reported in different levels of detail and in different cost formats. In addition the hardware components attributed to a given subsystem for costing (eg, receiver, collector, thermal transport, electric power generation, etc.) were not consistently assigned as reported by the different contractor teams. This situation is further complicated as some cost estimates specifically identified significant amounts for certain non-capital cost items (e.g. indirect cost, engineering services, contingencies, fees and owner's cost etc.), while others included these costs within the estimated costs of various subsystems, or ignored them. The reported costs are also given in different year dollars. The data reported for each design were reviewed and rearranged into a consistent format as part of this review. Table 4-1 lists the hardware components that were attributed to each major subsystem along with the explanation of various non-capital cost items.

As mentioned earlier (Section 2-4), the Amfac repowering design incorporates existing plant turbines and electric power generation equipment. It has no thermal storage subsystem. The Amfac team estimates give a detailed breakdown of capital costs by subsystems and components. They also detail material, labor and subcontract costs.

Rockwell preliminary design cost data are highly aggregated compared to the cost data of other design teams. Also, the cost data format as presented by Rockwell lumps together all structural, foundation and erection costs of the receiver tower, the thermal transport, the thermal storage and the electric power generation equipments under a single cost entry entitled "Field Construction - Power Complex". This entry represents 20% of the total Rockwell design costs. Thus, unlike other design costs, the receiver subsystem cost as reported by Rockwell does not include the

Table 4-1

Description of Various Capital and Non-capital Cost Items

Collector Subsystem

Heliostats; foundations; control and peripheral equipment; power and control wiring; beam characterization system exclusive of target; maintenance equipment and vehicles.

Receiver

Absorber unit; support structure; tower; foundation; instrumentation and controls; electric equipment and wiring; circulating equipment; auxiliaries; spares.

Thermal Transport

Piping; pumps; controls and valves; electrical and mechanical equipments; auxiliaries; spares.

Electric Power Generation

Electric plant equipment, service and protection equipment; wiring; switchyard equipment; turbine-generator and modifications; feed heating and condensing; solar steam generator; heat exchanger; transport fluid; circulating equipment; plant electrical; spares.

Thermal Storage

Storage tanks; piping; instrumentation; foundations; heat transport fluid.

Master Control

Computers; display consoles; unit protection; control panel; weather monitoring; instrument enclosures.

Balance of Plant

Land and site permits; site improvements; foundations fence; lighting; buildings; storage and maintenance; water supplies; fire protection, telecommunications; permanent tools.

Indirect Cost

Temporary construction facilities; construction services, supplies and expense; equipment rental; insurance; fuel cost; field staff subsistences and expense.

Engineering Services

Architect and engineering services; home office costs; specifications; analysis; drawing reviews; procurement and scheduling services; acceptance testing; construction and project management.

Contingency

Allowance for uncertainty in material quantities, pricing and productivity that exist within the preliminary design.

Fee

Compensation given over and above the normal expenses experienced by the general contractor.

Owner's Cost

Land costs; water rights; consulting and legal service; owner's managerial, engineering and financing services.

cost of the receiver tower, support structures, tower foundation, etc. This also appears true for the structural and foundation costs of thermal transport, thermal storage and electric power generation equipments.

The APS preliminary design report presents a fairly detailed capital cost breakdown in terms of various subsystem components and also gives adequate description of other non-capital cost items.

The cost data by EPE for the Newman Unit-1 design are also fairly detailed and a breakdown is given for material and labor costs associated with the delivery and installation of all subsystems and major equipments. The EPE electric design uses the existing plant turbine and electric power generation equipments. It also has no thermal storage.

4.2 Evaluation of Collector Subsystem Cost

Collector subsystem costs are currently the largest cost item in the SCR plant cost. They are also relatively easy to evaluate due to the similarity in the various collector subsystems. The differences in the contractors reported collector subsystem costs were also the highest compared to the cost differences of other subsystems. It was thus considered appropriate to evaluate the reported collector subsystem cost. These collector subsystems costs were calculated in terms of dollars per square meter of collector mirror area. These costs were found to range from the low of $\$210/m^2$ for the Rockwell plant to a high of $\$369/m^2$ for the APS design. The Rockwell aggregated description of the collector subsystem and "Field Construction - Power Complex" did not explicitly mention the costs of collector field electrical and heliostat foundations. Both Rockwell and Amfac plant designs assumed use of the ARCO third generation heliostats, while APS cost estimates are based upon the use of Martin Marietta improved second generation heliostats. The EPE design team estimated its cost of $\$317/m^2$ on the basis of a generic heliostat with a specification that resembles the ARCO third generation heliostats.

The Amfac design team gave the most detailed collector subsystem cost information. They reported the costs of heliostats at \$207/m^2 and another \$2/m^2 and \$3/m^2 for controls and shipping costs (Maui). Heliostat foundations, field electrical and fee account for respectively \$26, \$10 and \$15 per square meter. If one were to neglect the fee surcharge of \$15/m^2, the cost of the collector subsystem should be around \$250/m^2 and may be applicable to all of the designs, if ARCO heliostats were to be used. The direct cost savings to APS and EPE designs by such an assumption should be around \$$34 \times 10^6$(1983\$) and \$$12 \times 10^6$(1983\$) respectively. Based upon the evaluation of these collector subsystem costs it was estimated that depending upon the volume purchase, the current collector subsystem costs are projected to be \$200-250/m^2.

4.3 Comparison of Non-Capital Cost Elements

The five non-capital cost elements of indirect cost, engineering services, contingency, contractors fee and owner's cost were earlier described in Table 4-1. Different contractor teams used different cost approaches to cover the above cost elements. The Amfac cost estimates call for an indirect cost of about 9% of total direct cost. These indirect costs as described in Table 4-1 include costs of temporary construction facilities, construction services, equipment rentals, fuel costs, etc. The Amfac team estimates engineering services to be 10% of the total direct and indirect plant costs and identifies an additional contingency cost that is 15% of the sum of direct, indirect, and engineering services cost. Engineering services (Table 4-1) include costs of architect and engineering, specifications, reviews, procurement and construction management. Contingency costs include allowance, for uncertainty in material quantities, pricing and productivity. Amfac design costs also include contractors fees that are 3% of the total direct, indirect, engineering services and contingency costs. An owner's cost to be incurred by Amfac is also included in the total plant cost and is estimated as 10% of the total plant construction costs. The above mentioned non-capital costs for the Amfac design amount to 35.8% of the plant cost.

The highly aggregated Rockwell data appears to include some of the indirect costs in their single cost item of "Field Construction - Power Complex". Construction management cost that is part of engineering services is estimated as 2.3% of the plant cost. Rockwell cost data, however, do not appear to cover contingency and contractor's fee items.

The APS design team describes the indirect cost, engineering services and owner's cost as indirect costs and estimates them as 11.3% of the plant cost. Contingency allowance and contractor's fees are included in the APS direct capital costs.

The EPE team gives estimates of indirect cost and engineering services as 1.4% and 7.4% of plant cost. EPE, however, identified these indirect and engineering services as distributable costs and indirect costs. EPE definition of indirect costs covered costs of engineering design and specifications, selection and management of contractors, purchasing and scheduling. EPE cost estimates also include an allowance for contingency that is about 15% of all direct, indirect and engineering services except for solar collector and receiver equipments, since these equipments already included a +25% manufacturer's cost adjustment allowance. EPE described its contingency allowance as provision for design uncertainties and risks associated with commercial price which does not include a cost provision for items such as Acts of God, labor disputes, or schedule delays. The EPE team appears to have included the contractors fee in its direct plant cost. It also gives the details of owner's cost that are 2.8% of the plant cost. The above mentioned non-capital costs for the EPE design came to 15.8% of the total plant cost.

4.4 Comparison of Solar Plant Costs

Table 4-2 summarizes plant overnight costs (as if the plant were constructed instantly or overnight) for the four proposed SCR facilities consistently adjusted to 1983 dollars. The costs in Table 4-2 are the reported contractor's costs except where noted. The costs of various plant subsystems such as collector, receiver, power generation etc. are presented

Table 4-2

Summary of Plant Costs (1983 Overnight Costs)

	Amfac	Rockwell	APS	EPE
Collector	36% ($265/m^2)	31% ($210/m^2)	49% (↓) ($369/m^2)	50% (↓) ($317/m^2)
Receiver	16	27(A)	12	20
Heat Transport & Power Generation	6 (!)	29	17	9 (!)
Thermal Storage	-	5	8	-
Master Control & Balance of Plant	6	6	3	4
Non-Capital Costs(B)	36 (↓)	2 (↑)	11	16
	100%	100%	100%	100%
Total Reported Plant Cost	$40.2 x 10^6	$120.5 x 10^6	$215.1 x 10^6	$112.5 x 10^6
Adjusted Plant Cost	40.2 (↓)	120.5 (↑)	181.3(C)	100.6(C)

(A) Includes field installation cost of heat transport and power generation equipment

(B) Includes indirect, engineering services, contingency, fees, and owner's cost

(C) Based upon $250/m^2 collector

(↑ or ↓) Suspect Result

(!) Meaningful Difference

as percents of the total reported plant costs. These subsystem costs correspond to the description of Table 4-1 wherein lists of different hardware components are attributed to each plant subsystem along with the explanation of various non-capital cost items.

As discussed in Section 4-2, the collector subsystem costs for the APS and EPE design appears to be suspect. If these contractor's team were to use the competitive free market available rates that are used by the other design teams (Amfac, Rockwell), a significant reduction in their collector subsystem costs is possible. This would imply in a significant reduction in total plant cost. The adjusted plant costs for the APS and EPE designs that are based upon $\$250/m^2$ collector subsystem cost, are also given in Table 4-2. The suspect nature of reported collector subsystem costs of APS ($\$369/m^2$) and EPE ($\$317/m^2$) are also noted in Table 4-2 by an appropriate symbol. Similarly, other suspect data and meaningful data differences are identified in Table 4-2.

The listed Rockwell receiver subsystem costs, unlike other design cost estimates, represent only those equipments that are above the receiver tower elevation of 380 feet. The rest of the receiver costs are given under cost item "Field Construction -- Power Complex". Thus the receiver costs listed for the Rockwell designs are not consistent with receiver costs of other designs that include the cost of both the tower and tower foundations. The listed receiver costs of Rockwell were combined with the costs of "Field Construction -- Power Complex" and reported under receiver subsystem cost of Table 4-2. However, due to the highly aggregated nature of the Rockwell costs, these receiver costs would then also include the field installation costs of heat transport and power generation equipment. The Rockwell thermal transport costs ($\$10.1x10^6$) includes the cost of sodium receiving and purification equipment, the mixing tank, the argon cover gas equipment, safety equipment and the pipe and tank heating installations. The Rockwell electric power generation cost ($21.8x10^6) is primarily due to turbine-generator ($12x10^6) and steam generation equipments ($10x10^6). Electric power generation cost in Table 4-2 includes the cost of solar steam generation equipment.

The APS thermal transport cost ($11.1x10^6) is primarily due to large piping costs. The APS electric power generation cost ($25.8x10^6) includes the cost of steam generation equipment involving salt-steam heat exchanger ($10x10^6), transport fluid ($4x10^6), and water-steam circulation equipment. It uses the existing turbines and power generating equipment with some modifications and power wiring costs ($9x10^6). APS storage subsystem cost ($16.5x10^6) are primarily due to storage tanks ($7x10^6) and heat transport fluid ($6.7x10^6), which results in normalized storage costs of $2.4x10^6 per hundred MWht. Compared to this the Rockwell liquid sodium storage costs are $6.1x10^6 per hundred MWht.

The EPE reported plant costs provide a valuable estimate of plant labor costs ($22x10^6) that were based upon the labor rates of $21-38 per hour in the El Paso, Texas area during the summer of 1983. These labor costs represent a labor crew rate, including as appropriate, a foreman, journeyman, and support, benefits and allowances, overhead and profit for the contractor and appropriate small tool allowances. EPE reported receiver subsystem cost ($22.7x10^6) includes the cost of thermal transport as well as cost ($18.6x10^6) for the various equipments located above receiver tower. These receiver costs include spare panels and parts as well as various construction items involving temporary housing, erection equipment, site supervision and material procurement. This receiver cost ($18.6x10^6) includes a manufacturer's cost adjustment allowance of +25% and represents the upper limit of the commercially binding estimate ($14.6x10^6). The lower limit was -10% of this cost and represents a lower cost limit ($13.1x10^6). The EPE power generation cost ($10.4x10^6) is primarily due to cost of main and reheat steam pipes, insulation and valves ($9.1x10^6).

The lower power generation costs of both Amfac and EPE are meaningful (Table 4-2) and are due to the use of existing power generation equipments and the use of water-steam technology that unlike liquid sodium and molten-salt technology, does not require additional hardware for heat-exchanges and transport fluids.

The non-capital costs in Table 4-2, include the costs of indirect, engineering services, contingency, fees, and owner's cost. These non-capital costs were earlier individually described in Section 4-3. As marked in Table 4-2, both the high value of the Amfac non-capital cost ($\sim$ 36%) and the low value for the Rockwell cost ($\sim$2%) appear to be suspect. They should probably lie somewhere close to the reported values of the EPE and APS costs. The escalation costs and "Allowance-of-Funds-Used-During-Construction (AFUDC) as reported by both APS and EPE teams were excluded from the overnight plant costs of Table 4-2. These items, along with other assumptions (inflation rate, debt rate, etc.) are used to calculate the project cost and present worth given in the following section.

4.5 Project Cost and Present Worth Comparisons

The solar facility overnight plant costs as summarized in Table 4-2 are given in 1983 dollars. Depending upon the plant size and its complexity, the construction period for the four proposed SCR plants could range from 2 to 4 years. The plant construction costs actually paid over this time would be higher than the overnight costs and would include the escalation of costs to then-year dollars. These escalated project costs are summarized in Table 4-3 and are based upon an annual escalation rate of 7%. The construction time for a relatively small Amfac plant was assumed to require payments over two years, while those for the other three plants were assumed to extend up to 4-years. Annual construction payments for the Amfac plant were assumed to be 50% for both 1985 and 1986. Construction cost expenditure rates for both Rockwell and EPE design were assumed to be 10%, 40%, 40% and 10% respectively for the years 1984, 85, 86 and 87. These rates for the APS design were close to 5%, 10%, 65% and 20% respectively for the years 1985, 86, 87 and 88. Thus, compared to other construction cost profiles, the APS cost profile is assumed to be more dominant towards later construction

Table 4-3

Summary of Solar Plant Project Costs and their Present Worths

Project Costs

(In Millions of Escalated Then-Year Dollars)

Year	Amfac	Rockwell	APS	EPE
1984	-	13	-	13
1985	23	55	14	52
1986	24	59	29	55
1987	-	16	180	14
1988	-	-	55	-
Total Project Cost	47	143	278	134
Adjusted Project Cost	47 (↓)	143 (↑)	245[A]	119[A]

Present Worths[B] (1987)

	Amfac	Rockwell	APS	EPE
Adjusted Project Cost	57.7 (↓)	176.1 (↑)	260.0[A]	148.0[A]
o Per Collector Area	\$ 855/m^2[C]	\$986/m^2 (↑)	\$915/m^2[A]	\$831/m^2[A]
o Per Gen. Capacity	\$4860/kWe[C]	\$5385/kWe(↑)	\$3940/kWe[A]	\$3220/kWe(A)
o Per Net Energy	\$4230/MWhe[C]	\$2330/MWhe (↑)	\$2165/Mwhe (↑)[A]	\$2270/MWhe[A]
o Per Gross Energy	\$825/MWht[C]	\$775/MWt (↑)	\$650/MWht(↑)[A]	\$670/MWht[A]

(A) Based Upon \$250/m^2 Collector Subsystem Cost

(B) Based Upon 100% Equity and 15% Discount Rate

(C) Adjusted for EPE Indirect Cost

(↑or↓) Suspect Results

periods. These construction cost expenditure rates are derived from the contractor's data. The total project costs in Table 4-3 are given in millions of escalated then-year dollars. The adjusted project costs for the APS and EPE designs that are based upon the adjusted plant cost (Table 4-2) with $\$250/m^2$ collector subsystem cost were also calculated and given in Table 4-3. These project costs include the necessary plant escalation costs that are due to construction period and represent the actual money spent to construct a given solar facility. The suspect quality of data due to high and low non-capital cost assumptions for the Amfac and Rockwell designs has also been identified in Table 4-3.

In addition to the above mentioned escalation costs, there are additional costs penalities that are associated with the length of the plant construction period and the time required before the plant starts producing revenues. These costs are generally treated as part of an economic analysis, where a discount rate is applied to the various equity payments that take place at different times and their present worth is calculated at one reference date to account for the time value of money. Similarly the after-tax costs of all debt, tax benefits, and net revenue streams are appropriately taken into account and their present worth is brought to the above mentioned reference date. Assuming 100% equity and a 15% discount rate, the 1987 present worth of project costs for the various SCR designs are also given in Table 4-3. These present worths of project costs thus relates the construction period project costs to one reference time and properly accounts for the cost of invested money up to that reference time. Since, APS assumed its construction profile to be more expenditure dominant towards later construction periods, APS present worth costs are closer to overnight costs because of the shorter time between investment dates and starting revenue time.

The normalized present worth costs of the four solar designs are also given in Table 4-3. These normalizations were carried out over collector area, solar design point generating capacity, net annual power output, and gross annual thermal energy. For the APS and EPE plant designs these normalizations were carried out on the adjusted present worth costs that are based upon a $250/m^2 collector subsystem. The Amfac normalization was also carried out by making adjustments for non-capital costs, where such costs were reduced to the level of EPE non-capital costs (16% instead of 36%).

As seen from Table 4-3, the present worth project costs of the different SCR designs are around $850-900/m^2 for the existing repowered facilities and about $1000/m^2 for the new facilities. This collector area normalization helps to relate the costs of SCR designs with other solar energy concepts and designs. The generating capacity normalization helps to relate with other conventional power plants. As seen from Table 4-3, such normalization costs are high for both existing repowering cogeneration plant and the new stand alone facility. However, this type of normalized costs cannot determine the cost advantage of one SCR plant over another, since the different plant capacity factors that dictate the amounts of annual energy production are neglected in such costs. Normalization over annual net power generation corrects the above situation, as it relates with the actual plant performance. This type of normalization thus serves as a simplistic means to assess the relative cost-performance of different SCR designs and other solar power generating concepts. As seen from Table 4-3, except for the Amfac cogeneration plant, such normalized present worths are around $2200-2300/MWhe, or said differently these SCR plants generate net electrical energy output of 430-460 MWhe annually per million dollar of invested present worth cost. The high value of Amfac cost-performance is due to the cogeneration operation and lower turbine efficiency. The relative difference (5-8%) in the above cost-performance system estimates are too small to suggest a preferred design, inasmuch as detailed suspect differences and cost performance data quality uncertainties appear to be more important than the differences (e.g. collector reflectivity, operating loads, collector costs, indirect costs. etc.). For example, the suspect performance data as identified in Section 3-1 (APS mirror reflectivity, Rockwell operating load etc.) as carried through in the cost-performance data of Table 4-3, appear to be more significant than the meaningful differences attributed to different plant designs (APS receiver thermal losses, Rockwell field blocking). The selection of a preferred design is further complicated due to differences in the design insolations (sites), SCR plant sizes and operational modes.

Normalization over gross annual energy was done to relate the cost-performance of both cogeneration and power generation SCR designs. As seen from Table 4-3, such normalized present worth costs are around $700-800/MWht. The gross energy production represents the annual thermal energy production potential and does not include losses due to operating loads and plant availability. Again, both the electric and thermal energy normalization as mentioned above neglect the relative differences of annual operating and maintenance costs which may be different for different SCR designs. Also, these performance-cost relationships do not directly specify plant revenues, which are a function of both plant performance and product prices which vary from site to site. Operating and maintenance costs comparisons and a review of plant revenues for different SCR repowering plants/sites are given in Sections 5 and 6.

5.0 COMPARISONS OF OPERATING AND MAINTENANCE COSTS

5.1 Comparison of Different O&M Cost Elements

Operating and maintenance (O&M) costs as reported by various contractor teams reflect the relative complexity and plant size of different designs as well as O&M labor costs at various plant locations. These O&M labor and material cost estimates are summarized in Table 5-1 along with the number and types of personnel for operating the solar plant that are used by the various contracting teams and their associated total operating personnel costs. Similar information is also given in Table 5-1 for the solar plant maintenance personnel. The O&M costs in Table 5-1 and other related cost discussions in Section 5-1 are given in terms of 1983 dollars. The labor and materials cost estimates given in Table 5-1 were organized according to five different O&M cost elements that are defined below and which are followed by their discussion for each plant design.

1. Operations

Personnel: Cost of wages, overhead and benefits associated with additional personnel to operate the solar plant

Consumables: Expendable items used for heliostat washing, fuel, otherwise unaccounted purchased electricity, lubricants, water, chemical analyses, chemical replacement.

2. Maintenance

Personnel: Cost of wages, overhead and benefits associated with additional personnel to maintain the solar plant.

Material Replacement: Repair and replacement of failed equipment and materials consumed during maintenance activities.

Table 5-1

Comparison of Annual Operating and Maintenance Cost Elements

(In Thousands of Dollars, 1983)

	Amfac	Rockwell	APS	EPE
Operating Personnel	102	705	485	51
Consumables	94	100	72	8
Maintenance Personnel	116	907	485	136
Materials	78	840	406	111
Contracts	--	227	382	56
O&M Cost Total	$388	$2780	$1831	$362

(a) 4.3-personnel: 1.5 site supervisor, 1.5 receiver operator, 0.5 thermal transport operator, 0.5 non-solar equipment operator and 0.3 for heliostat washing. Avg. salary $23.7k.

(b) 5-personnel: one for each function covering, heliostat, mechanical, electrical, instrument and site. Avg. salary $23.2k.

(c) 14-personnel: 3 supervisory technical personnel, 10 operators and 1 clerical. Avg. salary $50.4k.

(d) 18-personnel: 3 supervisory and technical personnel, 14 operators and 1 clerical. Avg. salary $50.4k.

(e) 18-personnel: 1 planning supervisor, 2 shift supervisors, 4 control operators, 6 auxiliary operators, 2 water analysts, 1 test technician, 1 storekeeper and 1 clerk. Avg. salary $27k.

(f) 18-personnel: 1 mechanical foreman, 1 welder, 1 machinist, 1 mechanic, 1 helper, 1 janitor, 2 yardmen, 1 electrical and instrument foreman, 5 instrument repairmen, 3 electricians and 2 helper. Average salary $27k.

(g) 2-personnel: 1 plant engineer and 1 control operator. Avg. salary $25.6k.

(h) 5-personnel: 1 for new structures, 1 for heliostat field and 3 for balance of plant. Avg. salary $27.2k.

Service Contracts: Activities performed under service contract from the suppliers, e.g.: receiver elevator, master control equipment, heliostat array computers, chemicals, maintenance, etc.

A. Amfac O&M Cost Details

Amfac O&M costs are based on Bechtel experience, inputs from the heliostat and receiver supplier, and discussions with Amfac Sugar, Inc. personnel. Amfac O&M costs (Table 5-1) use an annual average personnel cost of $23,500 (1983$) and represents labor costs at the Amfac's Pioneer Sugar Mill. These personnel costs in terms of 1983 dollars, range from a low of $18,000/year (site maintenance) to a high of $27,000/year (supervisor, instrument maintenance). These costs include a 35% additive to cover costs of personnel benefits and overheads.

Operating consumables for the Amfac plant account for $\$94 \times 10^3$ (1983$) per year and consists of electric power, fuel, lubricants, water and chemicals. Of this, electric power costs are estimated at $\$44 \times 10^3$ and are due to auxiliary power requirements for the solar facility. Unlike other design teams, these purchased electric power costs were not accounted by Amfac in determining its net power production and plant revenues. Chemicals and supply costs for operating receiver, thermal transport and non-solar equipments are estimated at $\$35 \times 10^3$/year. Chemicals and fuel costs associated with the washing of heliostats are estimated at $\$15 \times 10^3$/year. Annual costs of maintenance materials is estimated at $\$78 \times 10^3$. Of this amount heliostat maintenance materials cost and spare parts were respectively estimated at $\$38 \times 10^3$ and $\$19 \times 10^3$, and the remaining costs are due to materials used for maintaining mechanical, instrument and electrical equipments.

B. Rockwell O&M Cost Details

Rockwell O&M costs are based upon annual average personnel costs of $50,375 (1983$) and represent PG&E high labor cost rates in San Luis Obispo

County, California. These PG&E rates may not accurately reflect labor costs for a third party venture. The high O&M cost for the Rockwell design may also reflect the relatively complex design involving a sodium system that calls for a more highly skilled labor force and higher chemical and material cost (Table 5-1). Also, the stand-alone Carrisa Plains solar plant calls for more supervisory O&M personnel, which further adds to the overall O&M costs. The above labor costs include a 47% payroll burden. The unburdened salary in 1983 ranged from a high of $47000 (plant superintendent) to a low of $27000 (helper, trainee). The annual salary of six management and engineering personnel averaged around $44,000. The annual average salary of the remaining 26 personnel averages around $30,000. The Rockwell report also suggests a possible O&M personnel reduction from 32 to 27 persons.

Rockwell O&M cost data for operating consumables, maintenance materials and service contracts are given in generic aggregates and do not list specific breakdown of these costs to the various O&M activities. The operating consumables were listed as chemicals, miscellaneous, and safety supplies and account for respectively $\$33 \times 10^3$, $\$42 \times 10^3$ and $\$25 \times 10^3$ annually in terms of 1983 dollars. The maintenance materials were listed as repairs and major overhaul and their annual expenditures were estimated at $\$0.5 \times 10^6$ and $\$0.34 \times 10^6$. The annual maintenance contract labor costs were estimated at $\$226.8 \times 10^3$. The functions or type of services to be provided by this contract labor were not given by Rockwell.

C. APS O&M Cost Details

The APS O&M cost estimate is based upon an average annual labor cost of $26,950 (1983$) and represents labor costs for the Tucson, Arizona location. The above labor costs were derived from the wage-benefit costs for a similar staff at the APS Saguaro plant during March of 1983. Table 5-1 summarizes the personnel operations as well as maintenance costs along with the number and types of personnel assumed for the Saguaro repowering plant.

The annual operating consumables involving makeup salt, deionized water, fuel, surfactant and chemicals were estimated at $\$72.0\times10^3$. Of this, $\$38.7\times10^3$ per year was estimated for heliostats washing and $\$29.3\times10^3$ for providing makeup salt that is based upon the assumption of requiring 0.5% of initial salt inventory. Even though the APS design which incorporates molten-salt technology and has relatively complex O&M requirements, the large plant size and the repowering of an existing facility help to reduce the solar-related incremental O&M requirements.

APS annual maintenance material costs of $\$406.7\times10^3$ are based upon an equipment failure probability and associated replacement costs that result in an annual expenditure of 28% of the initial cost for spares; or equivalently, the initial spares estimate represents approximately a 3-year supply of spares. The annual costs of maintenance contracts were estimated at $\$382.4\times10^3$(1983$). This included a salt purity maintenance contract of $\$325\times10^3$ from Olin Chemical and an additional cost of $\$55.2\times10^3$ for servicing master control equipment and heliostat array computers. The maintenance contract for the receiver elevator was estimated at $\$2.16\times10^3$/year. In an addendum to the final report (Ref. 4), the APS team assumed additional O&M costs of about $\$1\times10^6$(1983) for a stand-alone solar plant. Thus, the O&M costs for stand-alone solar plants estimated by the APS and Rockwell teams are very close to each other (Table 5-1).

D. EPE O&M Cost Details

EPE reported estimated O&M costs using the FERC accounts structure. Labor costs are based upon an average annual salary of $26,700 (1983$) and represent labor costs for El Paso, Texas. The EPE report does not mention anything about the personnel benefits or overhead costs that are generally associated with the salaries of the various O&M personnel. Thus, the EPE reported labor rates may not include the overall labor costs. EPE O&M costs assume that the washing of heliostats would be performed by outside contracted labor and is thus reported under maintenance contracts in Table 5-1. EPE O&M costs are based upon the assumed requirement of only 7 additional personnel - 2 for operating the solar plant and the rest for solar plant maintenance.

The current EPE Newman Unit-1 facility has an allocation of 13 O&M personnel. The existing Newman-Unit 1 fossil plants' annual O&M costs are estimated at $\$476 \times 10^3$(1983\$). The solar repowering of Unit-1 is estimated to have additional annual O&M expenses of $\$362 \times 10^3$(1983\$). Of this, the annual operating consumables were estimated to cost $\$8.5 \times 10^3$ and represent solar prorated costs of steam power that includes costs of water, chemicals, lubricants and safety equipments etc. The annual cost of maintenance materials were estimated at $\$111 \times 10^3$ and cover heliostat field spare parts ($\$39 \times 10^3$), receiver maintenance including panel replacement and painting ($\$39 \times 10^3$) and balance of plant maintenance ($\$16 \times 10^3$). The annual maintenance contracts of $\$55.9 \times 10^3$ include washing of heliostats ($\$32.6 \times 10^3$) and computer maintenance ($\$23.3 \times 10^3$). The above maintenance costs were based upon identifiable expected maintenance activities, EPE judgment and experience, and manufacturer recommendations.

5.2 Evaluation of Annual O&M Costs and Their Present Worth

As seen from Table 5-1, the O&M cost estimates by EPE are the lowest of the four designs. These estimates are about one-seventh as large as Rockwell O&M cost estimates for a stand alone plant that produces a similar amount of electric power from solar energy. The O&M costs for the APS solar plant are also high, inasmuch as it is a repowering facility of the existing Saguaro power generation plant. The APS repowering plant O&M cost estimates are about 5-times the corresponding EPE plant estimates for a facility that produces about twice as much electricity from solar energy. Both Amfac and EPE teams assumed the same number of maintenance personnel (5) for their water steam plants. The major difference is the Amfac and EPE operating personnel (4.3 vs 2) appears to be due to the provision of solar plant supervisor (1.5) and heliostat washing personnel (0.3) by the Amfac estimates. EPE estimates assumed that the solar plant engineer will be responsible for any supervisory duties and heliostats washing was done with outside contracted labor (Table 5-1). The EPE Team, however, estimated only one control operator which may not be adequate, inasmuch as the EPE solar plant was assumed to be operating throughout the year including weekends (except forced and scheduled outages). Thus, the EPE plant operating personnel seem to be underestimated.

The high O&M personnel estimates for both Rockwell and APS plants are due to additional O&M functions that are inherent in the liquid sodium and molten-salt plant designs. For example, the Rockwell liquid sodium plant design involves several additional O&M functions that includes sodium handling equipments, mixing tanks, argon cover gas equipment, sodium-water heat exchanger, safety equipments, hot and cold sodium pumps, sodium storage tanks and the pipe and tank heaters. Although, use of sodium has been successfully demonstrated in several nuclear power plants, it presents serious safety concerns and appropriate precautions must be taken, especially in the steam generator equipment. There may also be some constraints in relatively hard to find liquid sodium O&M personnel that are currently confined primarily in a few organizations (Rockwell, Government Labs). Nevertheless, sodium receivers have the inherent advantage of being more efficient and compact due to high thermal conductivity of sodium.

Similarly, there are also additional associated O&M functions for molten salt plant designs. Also, the molten-salt O&M personnel are currently concentrated in the chemical industry and unlike water-steam technology, molten-salt working fluid is not familiar to the current utility O&M personnel. The low O&M labor rates by the APS team ($27K/yr) involving molten-salt technology appear to be underestimated. These labor rates include allowances for personnel benefits, overheads and other payroll burden.

The EPE team does not mention any overhead cost in discussing its labor rate ($26K/yr). Yet these labor rates represent an all inclusive cost for their O&M labor. As mentioned earlier the EPE team seems to have also underestimated the labor requirement as well for the plant operation.

The O&M personnel requirements, labor rates, and annual costs in 1987 are summarized in Table 5-2. Appropriate identifications for possibly suspect data have also been marked in Table 5-2. For example, the Rockwell 50K/year average labor rate for 1983 appears to be rather high, inasmuch as these rates also include several plant operators and clerks.

The annual costs ($510K for Amfac) in Table 5-2 do not include property taxes, insurance, warranties, oversight expenses, and any other third party limited partnership expenses. Property taxes are approximately 1% of the assessed plant value and insurance covering vandalism, fire, etc. normally costs about 0.25% of the plant value. However, many states (e.g. Texas) currently provide property tax exemption for solar plant equipments while a few other states (e.g. California, Arizona, Hawaii) provide a limited time exemption of such property taxes. Thus Amfac and EPE reports did not include payments of any property taxes. APS also did not include property taxes in their final report. However, their addendum to the final report included property taxes beginning with the year 1990. Rockwell used an annual property tax payment of $\$0.3 \times 10^6$(1987$) to San Luis Obispo County for planning purposes to cover the costs of any burdens placed on the county due to the presence of the solar plant. Payments of such property taxes to various states and counties may be negotiable for solar plants. Moreover, the assessed property value of the solar plant may be significantly below the cost of the plant especially in the later years of plant life. The property taxes for all of the four repowering plants were neglected in this review.

Insurance costs were assumed to be 0.25% of the plant cost and increased by 7% per year for a given insured value. However, the insured plant value was assumed to decrease in proportion to the remaining plant life. Table 5-2 also summarizes the annual (first twelve months) insurance costs for the various repowering plants. Annual total O&M costs in Table 5-2 include both annual costs (O&M) and annual insurance.

Table 5-2

Evaluation Summary of Annual O&M Costs and Their Present Worths

	Amfac	Rockwell	APS	EPE
Operation & Maintenance				
Personnel	9.3	32	36	7 (↑)
Labor (1983$)	24K/Yr (↑)	50K/Yr (↓)	27K/Yr (↑)	26K/Yr (↑)
Annual Costs (1987$)	510K	3640K	2400K	480K (↑)
Annual Insurance (1987$)	120K	360K	600K	340K
Annual Total O&M Cost (1987$)	600K	4000K	3000K	820K
Percent of Project Cost	1.0%	2.3% (↓)	1.0%	0.4% (↑)
Percent of Annual Revenue	51%	39% (↓)	37%	20% (↑)
Present Worth of O&M Costs[a]	$\$3.4 \times 10^6$	$\$22.7 \times 10^6$	$\$16.1 \times 10^6$	$\$3.9 \times 10^6$
Percent of Project Cost	5.9%	12.9% (↓)	6.3%	2.6% (↑)

(a) Based upon 30-year plant life, 50% tax rate, 7% escalation, 15% Discount rate, 100% equity and 1987 time reference

(↑ or ↓) Suspect Result

The above annual total O&M costs were normalized to both project costs and annual revenues. Normalization of O&M costs as percents of project costs are often done for conventional power plants. Because of the relatively high solar project cost and high solar O&M costs, normalization over annual revenues was carried out to assess the relative magnitude of solar O&M costs with reference to the solar plant revenues. AS seen from Table 5-2 these solar plant O&M costs in terms of percents of project cost, ranged from a low of 0.4% for the EPE design (suspect underestimated value) to a high of 2.3% for the Rockwell design (suspect overestimated value). These O&M costs, however, ranged from 20 to 52% of annual plant revenues. The 20% O&M value for the EPE design appears suspect and is identified in Table 5-2. The Rockwell and APS O&M costs amounted to about two-fifths of their plant revenues. The relative moderate nature of Rockwell O&M costs (39% is due to the very high electric rate in the PG&E plant site. If the Rockwell plant were to be sited in APS or EPE service territories, the Rockwell O&M costs could be 70-75% of the annual plant revenues. Thus containment of solar O&M costs is essential for future solar plant economic viability and appropriate actions are required to achieve this objective.

Table 5-2 also lists the present worth of O&M costs along with the calculation assumptions (30-year plant life, 50% tax rate, 7% escalation, 15% discount rate, 100% equity and 1987 time reference). These present worth costs were normalized in terms of percents of projected costs and are given in Table 5-2. As seen from Table 5-2, the O&M present worth costs ranged from 2.6% to 12.9% of plant costs. Both low (EPE design) and high (Rockwell design) values are considered suspect and have been identified as such in Table 5-2. The present worth of O&M insurance included in the total O&M costs are less than 1% of the plant cost. The present worth of the neglected property taxes in various states and counties is expected to be less than 3% of the plant cost.

6.0 EVALUATION AND COMPARISONS OF SOLAR PLANT REVENUES

6.1 Evaluation of Energy Output and Energy Rates

Gross revenues of the solar plant depend upon the energy output of the solar plant and the rates that this energy can be sold in the area where the plant is located. The reported energy revenues by different contractor teams reflected different degrees of optimism and except for the Rockwell team were not well supported. The Amfac team over estimated these revenues, while the APS team grossly underestimated such revenues. Meaningful comparative evaluations of the different plant revenues required revision of these reported values for consistency and maximum solar benefit. The reported energy revenues in this section are based upon the maximum avoided-cost energy rates of the various concerned utilities at the sites of the different SCR plants. In the case of Amfac Pioneer Mill cogeneration plant, the revenues are derived from both the savings of thermal energy and the sale of electric power. The sale of the electric power, at a rate of 87.7 mills/kWh in 1987, used in this report is derived from the Maui Electric Company published rate (67 mills/kWh in 1983) for unscheduled power during on-peak time periods. These rates are significantly lower (almost half) of those that were assumed by the Amfac team. The savings of thermal energy was based upon the price of fuel oil that was assumed to be \$26.50/barrel in 1983 third quarter dollars. However, the proposed Amfac solar plant will displace about 68 acres of currently productive land that would otherwise raise sugar cane which would be processed to produce sugar, molasses and begasse. The reported yearly average forgone revenues due to the loss of the above products under the assumption of zero production costs were $\$0.19 \times 10^6$. The annual electric power sales and fuel oil savings were estimated at 10.9 GWh and 6795 barrels per year. These estimates are about one-third less than earlier published estimates.

The Rockwell 29.4 MWe solar plant design at Carrisa Plains assumes an annual electric energy production of 75,600 MWh. It is located in PG&E service area and since it is a stand-alone plant and under 30 MWe capacity, it could enjoy the maximum benefits under Section 210 of PURPA. Moreover, the California Public Utility Commission (CPUC) has been a leader in promoting renewable energy resources. In Order Instituting Rulemaking No. 2 (OIR-2), the CPUC ordered the major California electric utilities to file standard offer options for power purchase based on avoided cost principles. These options are:

- Facilities providing "as-available" electricity will receive energy avoided cost and "as-available" capacity payment in ¢/kWh that vary with time of energy delivery.
- Facilities that agree to certain performance standards may receive a "firm capacity" payment, rather than "as-available" payment. The "firm capacity" payment is available in \$/kW/year, and may be contracted and levelized for up to 30 years.
- Other types of offers involving time varying forecasted as well as levelized fixed energy price schedules are being formulated where levelized energy payments are higher than avoided costs during earlier fixed price periods and lower than avoided costs during later years.

The CPUC also allows utilities to enter into a non-standard contract provided it is filed for review and the Commission approves it. The electric power sales revenue in the Rockwell report is based upon such a non-standard offer, which assumes the following energy payment schedule.

First 5 Years:	9¢/kWh
Second 5 Years:	Greater of 10¢/kWh or 100% of energy avoided cost
Third 5 Years:	Greater of 10.5 ¢/kWh or a sliding scale of 98% to 90% of energy avoided cost
Subsequent Years:	90% of energy avoided cost

An independent evaluation of the above energy rates were made with the help of PG&E time-of-use standard fuel cost schedule and corresponding reported amounts of energy production as given in Table 6-1. These calculations result in a weighted average fixed rate of about 6.4¢/kWh for the year 1983-84. Details of the capacity credit revenues are given in Section 6-2.

Table 6-1

Details of Avoided Energy Cost for the Rockwell Solar Plant

PG&E Time-of-Use Schedule

	Summer (Period A) (May through September)	Winter (Period B) (October through April)
On-Peak	12:30 pm - 6:30 pm	4:30 pm - 8:30 pm
Partial-Peak	8:30 am - 12:30 pm	8:30 am - 4:30 pm
	6:30 pm - 10:30 pm	8:30 pm - 10:30 pm
	8:30 am - 10:30 pm (Saturdays)	8:30 am - 10:30 pm (Saturdays)
Off-Peak	All other hours, weekends & holidays	

Energy Production and Associated Avoided Cost Rates

	Energy Production Gwh/Year	Fuel Cost Schedule (1983 Summer Average) Mills/KWh	Energy Production Gwh/Year	Fuel Cost Schedule (1983-84 Winter Average) Mills/kWh
On-Peak	16.3	61.4	2.3	74.7
Partial-Peak	17.4	58.5	26.9	72.0
Off-Peak	6.4	56.5	6.4	60.1

It should be noted that actual standard offer energy prices could change significantly from year to year. For example, quoted rates during 1982-83 dropped by as much as 20% compared with rates quoted during 1981-82. Partial-peak rates, which influence solar revenues the most, increased by 35% from January 1983 to January 1984. This increase is attributed primarily to the use of high heat rate turbines (15×10^3 vs. 11×10^3 Btus/kWh) rather than increased fuel prices. PG&E published fuel prices for January 1984 are $5.4/MBtu which is only 1% higher than January 1983 prices. If the calculation of the average fuel avoided cost price for the year 1988-89 does not assume the continued use of the high heat rate turbines, the rate could drop by 0.5¢/kWh below the above-mentioned price of 9¢/kWh.

The APS and EPE designs involve repowering of the existing Saguaro and Newman plants. The APS team calculated the annual fuel savings by taking the difference in annual fuel expenses incurred to meet the projected load without repowering and the annual fuel expenses incurred with Saguaro Unit One repowered by solar. The APS team reported the annual before-tax value of fuel savings for various scenarios involving 100% oil displacement, 100% coal displacement as well as a fuel mix of both oil and coal that is based upon an APS dispatch analysis. The annual fuel savings based upon 100% oil displacement was estimated at 0.219×10^6 barrels per year (at 5.8 MBtu/bbl oil). The annual average electric power generation due to solar repowering was estimated at 120.3 GWh per year. This implies an average turbine heat rate of 10,560 Btu/kWhe.

The APS published avoided cost rates are applicable only to facilities under 100 kW. These avoided cost rates in 1982 were about 46 and 40 mills/kWh respectively for the summer (June through October) and winter on-peak hours (9 a.m. to 10 p.m.). Using the APS expected 7.8 percent average escalation rate based upon the Chase Econometrics Inc. forecast, the weighted average avoided cost applicable to the power output from the solar plant in 1987 was assumed to be 67 mills/kWh. This results in the highest first year revenues as compared to the other scenarios that were analyzed by the APS team.

The EPE team also calculated annual fuel savings that would be obtained by the solar repowered Newman Unit and used a detailed load forecast and dispatch analysis. These calculations were carried out for a 30-year time period, wherein solar energy and associated required fossil support energy varied from year to year depending upon chronological load shape, mix of available generation and various other parameters. The average annual solar derived electric power output was 65.2 GWh and varied from a low of 59.1 GWh/year to a high of 70.1 GWh/year. Two scenarios of solar fuel savings were presented for different natural gas base prices (1987). Scenario A was based upon an optimistic (high) natural gas price of $7.07/MBtu in 1987 that escalated at a rate of 12% per year through 1990 and 7% per year beyond 1990. Scenario B was less optimistic and was based upon a natural gas price of $5.36/MBtu in 1987 that escalated 10% per year through 1990, and 6.5% per year beyond 1990. The resulting electric energy price corresponding to the optimistic scenario A, was estimated at 69.2 mills/kWh in 1987.

6.2 Evaluation of Capacity Credit Rates

Capacity credit prices for different utilities reflect the marginal maintenance costs of the required power plants availability. The capacity credit price for the Amfac plant is assumed at 8 mills/kWh (1987). This is based upon the published difference (6 mills/kWh in 1983) in avoided cost for the Maui Electric Company between unscheduled and firm electric power during on-peak time periods. This assumption of firm electric power capacity credit for the Amfac plant is realistic as its plant design calls for continuously maintaining a fossil steam boiler.

Rockwell capacity credit revenues ($\$3.5 \times 10^6$) are based upon PG&E Standard Offer No. 2 (Reference 6) that requires power from a solar facility to be available for all of the on-peak hours (currently 12:30 p.m. to 6:30 p.m.) in the peak months on the PG&E systems. Presently the peak months are June, July and August. During these times there is a 20 percent allowance for forced outages in any month.

An independent calculation was also made of "firm capacity" revenue and was found to compare closely to the figure reported by Rockwell. The "firm-capacity" revenues are about 45 mills/kWh on the weighted average power output basis and remain constant throughout the 30-year term of the contract. The 30-year present worth from the above capacity payments are about the same as the one obtained from the capacity rate of 23 mills/kWh escalating at 7% per year.

These calculations are based upon the recently published PG&E "firm capacity" calculation methodology (Reference 6), seasonal allocation factors and "firm capacity" price schedule (first quarter 1984). Electric energy breakdown for different time periods was based upon the Rockwell report. The Rockwell "firm-capacity" credit calculation was based on seasonal allocation factors and "firm-capacity" price schedules that have since been changed (1-1-84) by a CPUC decision. Details of these capacity credit calculations are presented in Table 6-2. These calculations show that the "firm capacity" payments for a typical summer and winter months are respectively $\$688 \times 10^3$ and $\$29 \times 10^3$. These results show that the summer months play a dominant role in determining the amount of "firm capacity" payments. The most critical summer months that determine PG&E payments for such "firm capacity" credit are the months of June, July and August.

If one were to enter into an "as-available" capacity contract, (Standard Offer #1), instead of the above-mentioned "firm capacity" contract, (Standard Offer #2), the annual capacity credit revenues for the years 1983 and 1984 would be $\$1.4 \times 10^6$ and $\$3.4 \times 10^6$ respectively. These as-available energy credits are 24 to 55 mills/kWh (1987) on the weighted power output basis and they increase with the cost of power generation in the future years. This large increase in revenues is due to a very substantial jump in the 1984 capacity payment rates that are also given in Table 6-2. The big jump in revenues from 1983 to 1984 appear to be representative of the current PG&E incremental capacity heat rates for the

Table 6-2

Details of Capacity Credit Revenues for the Rockwell Solar Plant

Firm Capacity Revenue Calculations

Option 2 Allocation Factor	0.18540	0.01043
Period Price Factor ($/kW-Month)	29.5	1.7
Monthly Capacity Factor	~ 0.8	~ 0.5
Monthly Capacity Payment ($/Month)	$688x10^3	$24x10^3

As-Available Capacity Rates in Mills/kWh

	1983 Rates	1984 Rates	1983 Rates	1984 Rates
On-Peak	69.1	167.2	14.0	13.8
Partial-Peak	11.3	31.7	2.1	1.7
Off-Peak	-	-	-	-

on-peak and partial-peak time periods of 1984. These "as-available" capacity credit payment schedules change from year to year and are likely to increase by an average of 7% per year on a long term basis.

The APS team did not assign any capacity credit, because the solar repowered plant did not displace any capacity on the APS power grid. In a subsequent addendum report to their final report, the APS team assigned the APS avoided cost rates to calculate the present worth of the solar generated electric power. The APS published avoided cost schedule (for 100 kW) includes a provision of an additional 10% of the applicable avoided cost for "firm power". Based upon this, the resulting firm capacity credit for the APS plant is assumed at 6.7 mills/kWh (1987). However, the details as to the criteria for delivery of energy to qualify as "firm-power" are not known.

The EPE report describes the savings due to capacity credit on the EPE system starting in the year 2001 when the Newman Unit-1 is expected to be retired. Based upon this forecast, the EPE capacity credit value of 52 mills/kWh (1987$) was used in this report.

6.3 Comparisons of Plant Revenues and Their Present Worths

Table 6-3 compares the annual energy outputs, and energy and capacity credit rates that were evaluated in Sections 6.1 and 6.2. For the Amfac cogeneration plant, both electric and thermal energy production amounts are given. The energy and capacity credits are presented along with their expected escalation rates for different plant locations. The values given for 1987 are revised from the reported contractor results for consistency and maximum solar benefit (Sections 6.1 and 6.2). The energy rates represent the market values of the solar product. The high energy and capacity credit values for the Rockwell plant are meaningful and are based upon the published PG&E cogeneration and small power production reports (Ref. 6). Similarly, the relative high energy and capacity credit values for the Amfac plant are also meaningful as these are based upon the

Table 6-3

Comparison of Energy Revenues and Their Present Worths

	Amfac	Rockwell	APS	EPE
Annual Energy (MWhe)	10,900 & 6,795 bbls	75,600	120,300	65,200
Energy Rate (Mills/kWh) & Escalation (1987)	87.7 (!) 7% & 34.7/bbl 7%	90(!) 7%	67 (↓) 7.8%	69.2 (↓) 12% until 1990 7% beyond 1990
Capacity Credit (Mills/kWh) & Escalation (1987)	8(!) 7% - Firm	45(!) 0% - Firm	6.7 (↓) 7.8%	52(↓) 8% Starts in 2001
	[In Millions of Dollars, (1987)]			
First Twelve Months Revenues	1.0 - Electric 0.24 - Thermal[A]	6.8 - Electric 3.6 - Capacity	7.4 - Electric 0.7 - Capacity	4.0 - Electric -
First Twelve Months Revenues Less O&M	0.6 (1%)[A]	6.0 (4%)[A]	5.1 (2%)[A]	3.2 (3%)[A]
Present Worth[B] of Revenues less O&M	4.6 (10%)	28.3 (20%)	36.1 (15%)(↓)	20.6 (17%) (↓)

(A) In percents of project cost, escalated then year dollars
(B) Present worth calculations are based upon 30-year life, 50% tax rate, 15% discount rate and 100% equity
(↓) Suspect Result
(!) Meaningful Difference

published values of Maui Electric Company. As discussed in Sections 6-1 and 6-2, the energy capacity credit values for the APS and EPE plants may be suspect over estimated values. Future expected escalation rates of these energy and capacity credit values are also given in Table 6-3.

The computation of revenues for future years requires an assumption of these energy escalation rates. The reported escalation rates of energy prices by various design teams were different and contained different degrees of price optimism. For example, Maui Electric Company did not foresee any electric price escalation between 1983 and 1987. In order to develop a comparative revenue stream of the various solar plants, a 7% escalation rate for both oil and electricity was assumed for the Amfac plant. These escalation rates are comparable to the ones used by the other repowering teams. The zero capacity credit escalation rate for the Rockwell plant is meaningful (Section 6.2) and is based upon the published PG&E data on firm capacity rates. The EPE energy escalation values in Table 6-3 correspond to the optimistic energy price scenario forecast of EPE report.

Table 6-3 also summarizes the expected revenue streams for the various design teams during the first 12-month operational time period. Thus the first year revenues for firm-electric and thermal energy for Amfac plant were estimated at about $\$1\times10^6$ and $\$0.24\times10^6$ respectively. The costs of forgone revenue were neglected for maximum solar benefit. Similarly, the first full year avoided cost revenues of $\$6.8\times10^6$ were calculated for the Rockwell plant. In addition to these revenues from a non-standard power-sale agreement, capacity credit revenues of $\$3.6\times10^6$/year are obtained that are based upon PG&E Standard Offer No. 2. As mentioned earlier these firm capacity credit revenues would remain constant throughout the 30-year term of the contract.

Table 6-3 also lists the first year net revenues. These are also reported as percent net earnings of project cost for convenient comparisons with other investments. These net revenues are obtained by subtracting the O&M costs (Table 5-2) from the gross revenues. The 30-year present worth calculations of the net revenue streams were also carried out based upon a 30-year plant life, 50% state and federal tax rate and 15% discount rate. Their values as percents of project costs are given in Table 6-3.

7.0 REVIEW AND COMPARATIVE EVALUATION OF DIFFERENT TAX BENEFITS

7.1 Review and Requirements of Different Tax Benefits

Tax benefits play a key role in the viability of constructing a solar plant in the private sector. However, the treatments of different tax benefits by the contractor teams were inconsistent and inadequate. This is further complicated as different teams assumed different types of plant ownership with varying assumptions for economic parameters and returns on capital investments. In order to obtain the maximum benefit from the various tax provisions for each of the proposed plants, an independent Aerospace analysis was carried out. This analysis is based upon the contractor data, consistent economic parameters and assumes a third-party ownership for all of the proposed plants which is able to receive the full tax benefits. Since the potential financial benefits derived from the various tax benefits are very significant, it is essential to review the provisions and requirements of the various tax laws.

A. Review of Different Tax Benefits

Tax benefits from the construction of solar plants are derived from both the standard investment-related tax provisions and the special laws that affect only the renewable energy sources. The standard investment-related tax benefits of investment tax credit, depreciation and interest deductions apply generally to all business ventures. To complement these standard tax benefits, certain special federal and state laws have been promulgated to encourage the development of renewable solar energy sources. The various tax provisions that are responsible for standard and special tax benefits are discussed below:

Standard Tax Benefit Provisions

The federal investment tax credit [IRS Code Section 46(a)(2)(B)] allows a tax credit amounting to 10% of solar plant construction costs classified as "section 38 property". Solar plant costs can be depreciated (IRS Code Section 167 and 168) according to the following 5-year cost recovery schedule.

Ownership Year :	1	2	3	4	5
Depreciation, %:	15	22	21	21	21

Utility ownership of a solar plant will not be qualified for the above mentioned 5-year depreciation schedule. Also the basis reduction provisions of TEFRA (Tax Equity and Fiscal Responsibility Act, P.L. 97-248) requires that the basis of an asset (the cost figure used in computing depreciation) be reduced by one-half the amounts of the investment and energy tax credit that is claimed on federal tax returns. Thus, the depreciation benefits would be somewhat reduced with the use of the energy tax credits.

The usual tax benefits for ventures that are financed by borrowed money allows deduction of interest costs on federal income tax [(IRS Code Section 163(a)]. Similar interest cost deductions are also available in various state tax returns. If monies can be borrowed at effective rates below the required return on investment, then leveraging the financial structure of the project results in a positive benefit. The amount of the benefit depends on the amount of debt (leveraging), interest rate, tax liability and required discount rate.

These benefits are due to the resulting lower present worth debt cost as compared to the present worth equity cost of same funds. For example, the present worth of a million dollar debt costs at 12% interest, 30-year loan, 50% tax rate and 15% discount rate is about $\$0.48 \times 10^6$. Thus, for every dollar borrowed on the above terms there is a net benefit of about 50-cents provided this borrowed dollar can bring a 15% return (discount rate). This benefit increases with increased leveraging (debt) until the owners tax liability or plant revenues can not warrant or service any further leveraging. Economic calculations that are performed without concern for such leveraging limits (project loan service ability) can be very misleading. A highly misleading internal rate of return on equity (IRROE) can result where excessive leveraging results in negative yearly cash flows. In this situation the principal effect of a large IRROE is to assign a small present worth to large future losses.

Special Tax Benefit Provisions

A 15% Solar Energy Tax Credit provision [IRS Code Section 46(a)(2)(C)(1)] was enacted by the Crude Oil Windfall Tax Act (P.L. 96-223) and is applicable to the costs of "specially defined solar energy property". This credit is not available to a utility company [IRS Code Sections 48(I)(17) and 46(f)(5)]. It was also assumed that no portion of the above investment was financed by non-taxable grants, publicly subsidized or government-subsidized loans, or industrial revenue bonds as such portions of an investment are not eligible for Energy Tax Credit [IRS Code Section 48(2) (11)]. This credit is not affected by loan guarantees or state and local tax credits, but is scheduled to expire December 31, 1985.

Many states also provide additional state tax credits and depreciation benefits that are available to solar central receiver plants. Some states also provide exemptions from both property and sales taxes. States with favorable state tax benefits are given below:

Arkansas	100% deduction
Arizona	30% Credit in 1984 and subsequent reduction of 5% per year expiring on December 31, 1989
California	25% credit
Hawaii	10% credit
Massachusetts	100% deduction
North Dakota	5% credit for each of 2 years
Ohio	10% credit
Oklahoma	15% credit
Oregon	35% tax credit, of which 10% for first 2 years and 5% for subsequent 3 years

The above states do not impose any dollar limit to their tax credits. Several other states (e.g. Alaska, Colorado, Indiana, Kansas, Maine, North Carolina, Rhode Island, South Carolina, Utah, and Vermont) impose a dollar amount limitation on their state energy tax credits that render them of little use in connection with any MW-size central receiver plant.

State tax benefits for the Amfac plant are based upon 10% state tax credits that are assumed to be available throughout the construction phase of the project. California state tax benefits for the Rockwell plant are based upon the use of 25% credits (California Administrative Code Title 20, Chapter 2, Subchapter 8) on those portions of the plant cost that were incurred before December 31, 1986. State depreciation on the remaining cost above the amount of state credit used the 3-year double declining balance procedure. Similarly, Arizona state tax regulations were used to calculate the present worth of the APS state tax benefits. In Arizona, the state exempts solar investments from property taxation (through December 31, 1989) and from the Business Sales and Excise taxes.

B. Requirements of Tax Benefits

In order to derive the maximum possible tax benefits, the SCR plant ownership must have large tax liabilities for both federal and state taxes for several continuous years. Table 7-1 gives the yearly requirements of such federal and state taxable incomes for the four central receiver designs in order to get maximum possible benefits (except for leveraging) from the various favorable tax provisions. Depending upon the amount of debt leveraging, the requirements for the taxable incomes would be even higher. If the plant ownership does not have adequate tax liabilities, the present worth of the various federal and state tax benefits can be significantly reduced depending upon state and federal tax liabilities, amounts of unused federal and state tax benefits and ability to carry forward or carry backward certain tax benefits that have such provisions. As seen from Table 7-1, full use of state tax benefits calls for a very substantial state taxable income requirement. For example, in order to fully utilize the

Table 7-1

Incomes Requirement for Federal and State Tax Benefits

(in millions of escalated then-year dollars)

	Amfac		Rockwell		APS		EPE	
Year	Federal	State	Federal	State	Federal	State	Federal	State
1984	–	–	6.1	31.9	–	–	6.1	
1985	10.7	35.8	26.2	136.6	6.7	62.7	24.5	
1986	11.5	38.3	28.1	146.2	13.2	99.7	19.2	
1987	5.8	–	25.2	89.1	64.9	367.3	21.8	
1988	8.6	–	26.1	33.9	53.7	93.9	21.8	N/A
1989	8.2	–	24.9	16.9	42.2	–	20.8	
1990	8.2	–	24.9	–	40.3	–	20.8	
1991	8.2	–	24.9	–	40.3	–	20.8	
1992	–	–	–	–	40.3	–	–	
Total	61.1	74.1	186.4	454.6	301.6	623.6	155.9	N/A

California and Arizona tax benefits, the Rockwell and APS plant ownership would require state taxable incomes that are about twice the requirements of federal taxable incomes. This type of central receiver ownership may be more difficult to arrange where relatively few companies or individuals have very large taxable incomes. Moreover, in a third-party limited partnership, plant owners are likely to be distributed over many states and thus would not be able to take advantage of state tax benefits.

It is also assumed that various solar plants are not owned by any utility (or, at least the utility ownership percentage is less than 50%), because utility ownership does not qualify for the 15% Energy Tax Credit or a 5-year ACRS depreciation schedule.

The SCR power plant can also get additional benefits and protection under PURPA, which requires utilities to accept interconnection with qualifying generation facilities and to pay for power delivered by such a facility at a rate equal to the avoided cost of the utility. However, in order to qualify, these facilities must have a capacity of less than 80 MW and derive at least 75% of its energy from renewable resources. If the SCR facility is under 30 MW such as the Rockwell plant, then additional benefits under PURPA are available that exempts a solar facility from both state and federal utility regulation, including regulation that control the allowed rate of return on investment.

7.2 Comparisons of Different Tax Benefits and their Present Worths

The leveraging benefits of the four SCR plants are summarized in Table 7-2. These leveraging benefits were obtained by first calculating the maximum amount of debt which can be serviced by the first year net revenues received from the sale of electricity. The amounts of yearly net revenues thus determines the theoretical maximum leveraging limits for each solar plant that may be obtained without experiencing negative cash flow. For example, in the case of the Rockwell plant, the first-year annual net revenues are around $\$6 \times 10^6$. For a 12%, 30-year loan amount, this can

Table 7-2

Present Worth of Leveraging Benefits

[In Millions of Dollars, (1987)]

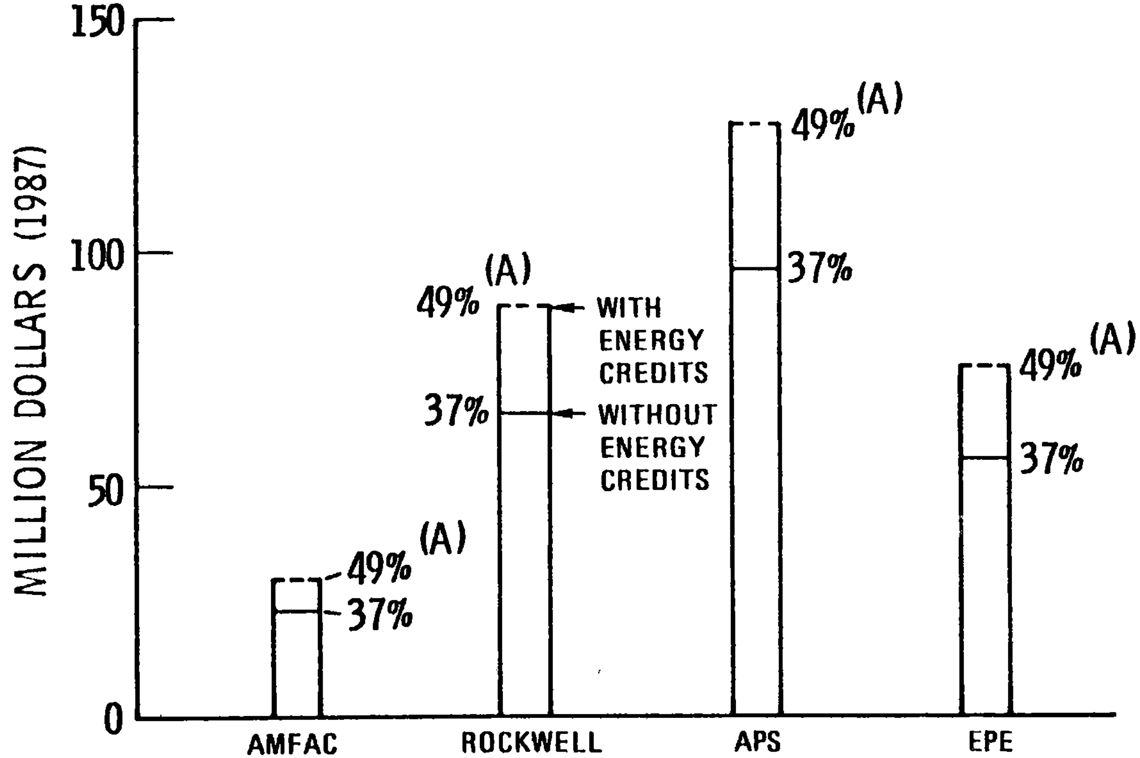
	Amfac	Rockwell	APS	EPE
First Twelve Months Revenues Less O&M	0.6	6(↓)	5.1(↓)	3.2 (↓)
Maximum Debt Leverage	4.8 (10%)[A]	48 (34%)[A](↓)	42 (17%)[A](↓)	26 (22%)[A] (↓)
Present Worth of Leveraging Benefit	2.4 (5%)	24 (17%) (↓)	21 (9%) (↓)	13 (11%) (↓)

(A) In percents of project cost, escalated then year dollars, calculated at 15% discount rate, 30-year debt at 12% and 50% tax rate

(↓) Suspect Result

service a maximum debt of $\$48 \times 10^6$. The present worth of this debt at 15% discount rate is approximately $\$24 \times 10^6$(1987). Again, actual leveraging amounts would be somewhat lower than these limits depending upon the financial strength of the plant ownership and future revenue certainty. Using the maximum debt amounts, the present worth of the leveraging benefits in Table 7-2 were calculated at a 15% discount rate, 30-year debt at 12% and 50% tax rate.

Figure 7-1 presents results of the present worth calculations of the various federal and state tax benefits that are available to the four central receiver repowering plants. These present worth calculations are based upon the construction costs and schedules of Figure 7-1 and assumptions of 30-year plant life, 15% discount rate, and 50% tax rate. The calculations in Figure 7-1 also are itemized for each tax provision in terms of their present worth benefits. It was assumed that 95% of all the SCR costs belonged to "Section 38 property" for the investment tax credit or "specially defined solar energy property" for the energy tax credit. As seen from Figure 7-1, the present worth of all the federal tax benefits recovers about 49% of the project cost with energy credits and 37% without energy credits. Possible state energy benefits may recover an additional 5 to 10% of the project cost to some owners provided these owners have adequate tax liability in a given state. The bar-charts in Figure 7-1 however, do not include these state tax benefits, as these benefits will not be available to all the plant owners.



PRESENT WORTH IN MILLIONS OF DOLLARS (1987), CALCULATED AT 15% DISCOUNT RATE AND TAX RATE OF 50%

	AMFAC	ROCKWELL	APS	EPE
INVESTMENT TAX CREDIT	5.5	16.7	23.1	14.2
POSSIBLE ENERGY TAX CREDIT	8.2	25.1	35.3	21.2
DEPRECIATION	14.8	45.0	72.7	37.6
POSSIBLE STATE TAX BENEFITS	2.8 (4.9%[(A)])	19.0 (10.8%)	18.3 (7.2%)	N/A

[(A)] In percents of project cost, escalated then-year dollars

Figure 7-1

Present Worth of Various Federal and State Tax Benefits

8.0 SOLAR PLANT ECONOMIC ASSESSMENT AND BREAKEVEN REQUIREMENTS

8.1 Benefits and Cost Comparisons of Solar Plants

The private sector investment in SCR plants at any point in time will require a reasonable amount of return from such ventures. The benefits/returns from a solar plant are obtained in the form of revenues from the sale of energy (electricity) and various conventional and special tax benefits. Details of the energy sale revenues of the four central receiver plants are discussed in Section 6. These revenues are calculated on the basis of annual electric output, electric sale price including payments due to capacity credits, and savings due to any thermal energy displaced. Annual energy output from the four solar plants are based upon their system design and plant performance that were described in Sections 2 and 3 respectively. The electric and thermal energy rates along with capacity credit and the corresponding future escalation rates are discussed in Section 6. The annual operating and maintenance (O&M) costs that must be subtracted from the gross energy revenues to obtain net energy revenues are given in Section 5. Present worths of these energy revenues less O&M expenses are summarized in Section 6 (Table 6-3).

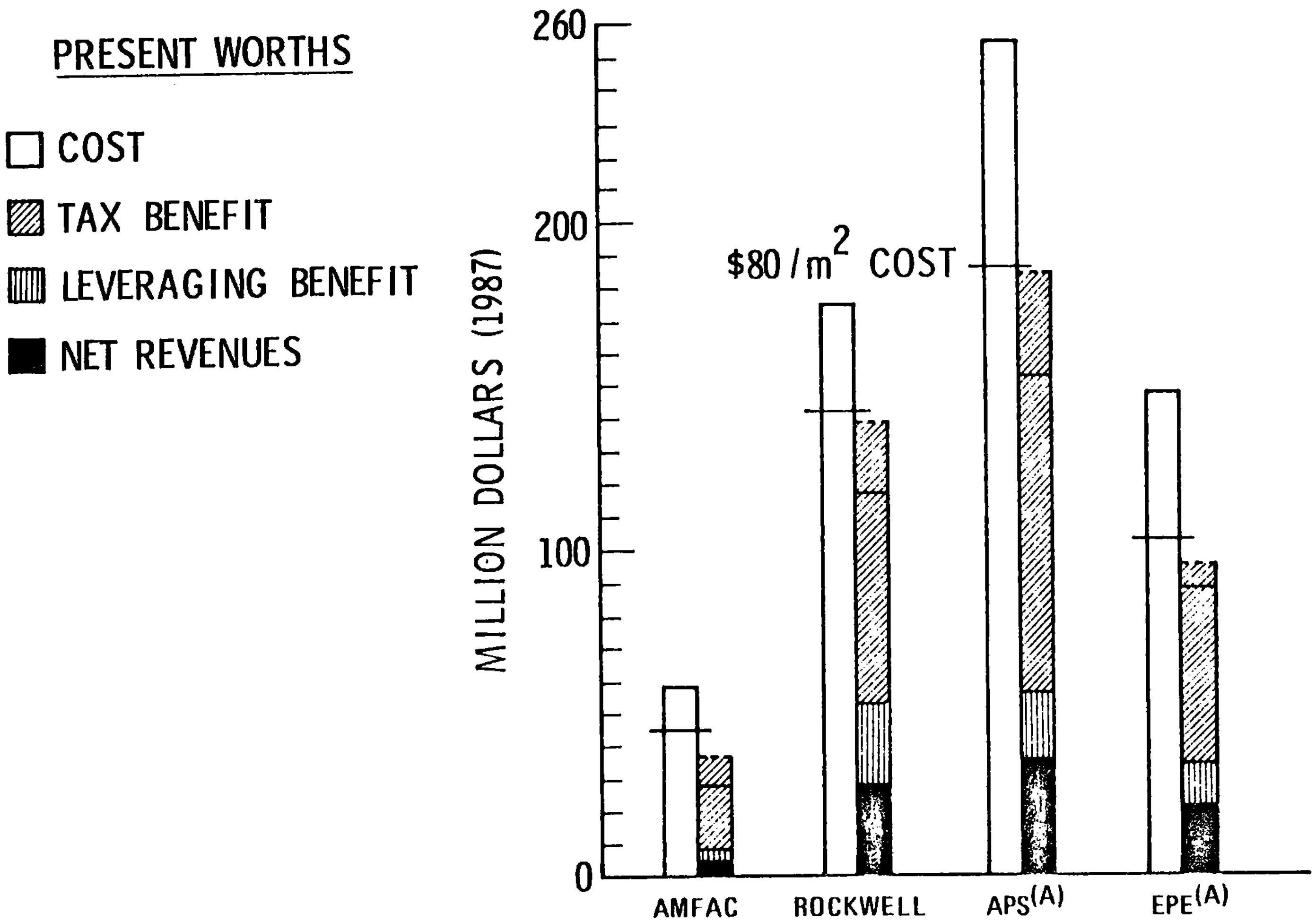
The nature and restrictions of various tax benefits are given in Section 7. The amounts of conventional tax benefits due to depreciation and investment tax credit, as well as the special energy tax credit depend upon the size of plant investments. These solar plant investment costs are given in Section 4 (Table 4-3). Using the construction cost schedule of Section 4, present worth of the various tax benefits are summarized in Section 7 (Figure 7-1). In addition, the conventional tax benefits due to debt leveraging is discussed in Section 7. The maximum leveraging for the various plants were calculated on the basis of the net annual revenues and are given in Section 7 (Table 7-2). Present worths of leveraging benefits for the solar plants were calculated in Section 7 (Table 7-2).

For a private sector third party investment in a solar plant, the present worth of all the benefits should be close to the present worth of the plant cost. The overnight plant costs for the four SCR plants are given in Section 4 (Table 4-2). These overnight plant costs are given in terms of 1983 dollars and do not include cost escalations (inflation) during construction years and of the effect of the time-value of money during construction. The construction costs of the four SCR plants in escalated then-year dollars as well as their present worths are given in Section 4 (Table 4-3).

The present worths of the solar plant benefits and costs for the four SCR plants are compared in Figure 8-1. Numerical values of these plant benefits involving energy revenues, leveraging and tax reductions are given earlier in Tables 6-3, 7-2 and 7-3. As seen from Figure 8-1, solar plant benefits for all the four plants can be ranked in order of tax benefits, energy revenues and leveraging benefit. Figure 8-1 presents tax benefits for cases both with and without federal energy tax credits. Including the federal energy tax credit, tax benefits account for about half of the solar plant costs. Tax benefits without the federal energy tax credit (separated by horizontal lines in Figure 8-1) still account for about 37% of the plant cost. These conventional tax benefits (~ 37%) are available to any industrial plant. However, the sum of all plant benefits do not recover the present worths of total plant costs. This fact can easily be summed up with the help of benefit-to-cost ratios that are also given in Table 8-1. These benefit-to-cost ratios can be brought to one by either reducing the cost of solar plant or increasing its benefits. Increased plant benefits are possible with increased energy revenues and tax benefits. While the tax benefits depend upon legislation, the energy revenues can be increased by one of the three ways:

- higher energy rates
- higher plant performance, i.e. more gross sales
- lower O&M expenses, i.e. more net sales

Increased energy revenues also increases potential leveraging benefits because of an increased ability to service a large debt. Reduced plant costs also lower tax benefits such as depreciation or credits because of the lower investment basis. In fact, for every one dollar reduction in plant



BENEFIT-COST RATIO	AMFAC	ROCKWELL	APS[A]	EPE[A]
---- WITH ENERGY TAX CREDITS	0.62	0.79	0.72	0.72
—— WITHOUT ENERGY TAX CREDITS	0.50	0.67	0.60	0.60

[A] Based upon $\$250/m^2$ collector

Figure 8-1

Comparisons of Present Worths of Benefits and Costs for Solar Plants cost, a loss of almost 50 cents results in the tax benefits under the set of assumptions used here (15% discount rate, 50% tax rate, availability of energy tax credit etc.). For example, the present worth cost reduction attributable to the availability of $\$80/m^2$ collector subsystems was calculated and are indicated by the extended horizontal lines in Figure 8-1. The availability of $\$80/m^2$ collector subsystems appear to reduce total plant costs by 20 to 30%. The apparent leveling up of the plant costs with the benefits should not be interpreted to mean that the plant benefit-cost ratio is one. In fact, the reduction in plant cost of 20 to 30% would also lower the tax benefits (dotted area in Figure 8-1) by about the same percent. An iterative calculation procedure revealed that collector subsystem cost reductions alone would not be sufficient and additional plant cost reductions of about 30% are required from other subsystems for a breakeven solar plant (benefit-to-cost ratio = 1).

SCR benefit cost comparisons are based on the assumptions of 15% discount rate, 12% debt, 7% energy escalation, 50% tax rate, 30-year plant life, ownership ability to receive full tax benefits and maximum debt leveraging. The requirements of 15% after-tax return on investment (discount rate) is considered appropriate especially with the use of 12% debt, 7% energy escalation and possible risks of earlier SCR plants. However, if a lower (5-10%) after-tax return on investment is acceptable by the SCR plant owners, breakeven plant conditions can result and plant construction would not require additional cost reductions.

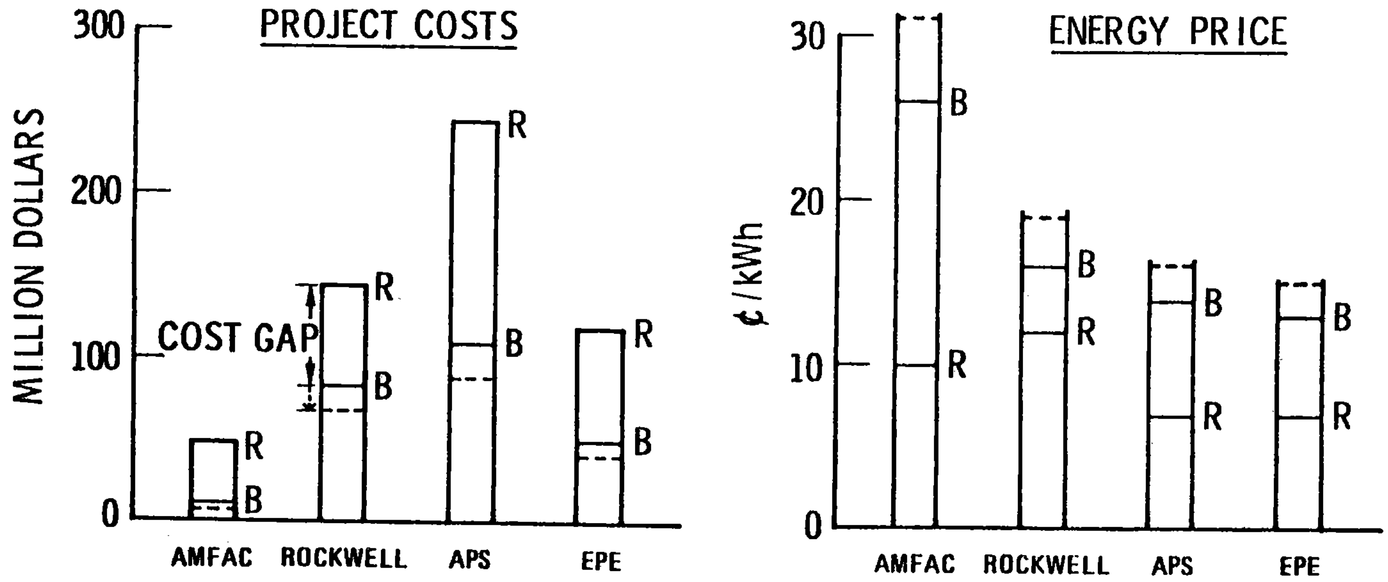
8.2 Solar Plants Breakeven Requirements

The solar plant benefits that are given in Figure 8-1 are based upon the assumption that all of the four plants would be able to receive full tax benefits. In spite of this favorable assumption, the cost gaps between the various plant costs and their benefits are significant. Appropriate reduction in plant costs are required to eliminate these cost gaps. These reductions in plant costs would also yield lower tax benefits. For breakeven project costs (escalated then-year dollars), the values of the various plant benefits involving tax reductions, revenues and leveraging are equal to the plant costs. Figure 8-2 presents the breakeven requirements of the various solar plants. The left-side of Figure 8-2 presents the breakeven requirements of solar project costs. These breakeven cost requirements are given for cases with and without federal energy tax credits. The cost gaps between the reported project costs and the breakeven cost requirements presume that there is no change in plant performance or energy prices. As seen from Figure 8-1, current solar plant economics results in larger cost gaps for larger plants even after economies of scale. To achieve economic breakeven, real plant cost must be reduced to one-third of the current values.

The right-side of Figure 8-2 presents breakeven energy prices. These are real price increases in terms of 1987 dollars. In addition to providing higher net energy revenues, the higher energy prices also permit more debt and leveraging benefits . As seen from Figure 8-2, for a breakeven plant real energy prices should increase by a factor of 2 to 2.5.

These breakeven energy prices are predicated on no further improvement in plant performance or cost reductions. Another alternative for achieving a breakeven solar plant is to increase overall performance. Just as electric rates are constrained by world energy prices, overall SCR plant performance is limited by the laws of physics and engineering principles. Current overall plant efficiencies of 16-17% (Table 3-2) can be increased by 20-30% through improved subsystem efficiencies. These improvements are constrained by the physical limitations due to collector cosine and shading, attenuation, receiver thermal losses, power generation and operating loads (Table 3-1). However improvements in collector reflectivity, field blocking, receiver spillage, receiver reflectivity, reheat turbine and plant availability are capable of a net performance improvement of 25% (Table 3-1).

Future energy prices may well increase by 25% in real dollars as the world current energy reserves decline and higher costs are experienced to add new reserves. Real reductions in plant costs by 25% are possible due to



PROJECT COSTS ($10^6)					ENERGY PRICES (¢/kWh)			
$47	$143	$245	$119	← R (Reported) →	10	12	7	7
*$11	$ 84	$110	$ 54	← B (Breakeven) →	*26	16	15	13
**$ 9	$ 68	$ 90	$ 43	← B (Breakeven) →	**31	19	18	16

R = REPORTED   B = BREAKEVEN { * ——— with Energy Credits; ** – – – without Energy Credits }

BREAK-EVEN SYSTEM COST = $250-400 / m^2

BREAK-EVEN PERFORMANCE = 1000-1200 mWh / MILLION DOLLARS

Figure 8-2

Solar Plants Breakeven Requirements

improved and large scale production of heliostats, receiver and storage subsystems (Table 4-2). Improvement in plant control systems and subsystem design and reliability may reduce the O&M expenses by 50% (Table 5-1). The resulting overall impact of these changes would be sufficient to make a solar central receiver plant economical at several U.S. locations. For more favorable plant locations (e.g. California), breakeven plant economics can result with smaller net improvements.

For companies with a longer term motivation and commitment to developing SCR hardware, earlier construction and operation of a plant may be desirable especially if they see that necessary improvements can be achieved in the near future. Under such circumstances, a company may not limit its economic thinking to the outcome of its first SCR plant and would evaluate less tangible long term benefits and may see the first SCR project as a springboard to several other projects with more favorable economics. For the earlier SCR projects, different companies may have to share the financial responsibilities of different risks and distribute these risks according to the areas of expertise, and future business, of each organization. Any single company, if left with the total burden of all the risks may be either unwilling or not have the ability to go ahead with the early SCR plants. For example, the companies should (a) structure the ownership so that the various available federal and state benefits are fully utilized, (b) share the various downside risks, c) obtain suitable loan (leveraging) from a party interested in the success of SCR project and d) be willing to accept lower economic benefits from the first SCR project.

9.0 CONCLUSIONS

9.1 Study Focus and Design Comparisons

The various SCR design studies reported here were aimed at near-term actual construction with specific sites, applications and designs. Obviously, the results do not represent future improved or optimized designs that may result with improved overall plant performance. The available documentation places heavy emphasis on plant designs, specifications and system operations and lack many details on performance and costs. These performance and costs data are needed and should be verified through testing of components and actual costs bids.

9.2 Contractor Data and Preferred Design

The various design teams used different design concepts and plant sizes. They used different receiver designs and working fluids. Some used storage; while others didn't. Comparisons of the four designs results does not support selection of one SCR concept over another. Selection of a preferred design was difficult due to several suspect differences involving collector costs, O&M expenses, indirect costs, plant availability, operating loads, collector reflectivity, etc. These suspect differences are larger than the meaningful differences attributed to different plant designs. The selection of a preferred design is further complicated by different proposed sites (insolation), plant sizes and applications. Corrections to some of the suspect data (e.g. collector cost, indirect cost, etc.) were made, where such corrections were rather straightforward and did not require redoing the extensive engineering tradeoffs and evaluations that were assigned to the contractor teams.

9.3 Current Solar Plant Economics

Current plant costs, normalized to unit collector area are around \$900-1000/m^2. Current plant performance may be characterized by an expected annual energy production of about 450 MWhe of electricity per one million dollars present worth of investment (\$2200-2200/MWhe). These design studies have established a believable range of collector subsystem costs (\$200-250/m^2) and eliminated the large collector cost uncertainties that existed before these studies were conducted. Tax and leveraging benefits are very important in the current solar plant economics. Together, they recover about 50% of the plant cost, even without the use of special energy tax credits. These tax and leveraging benefits are available to most industrial investments and solar plants are not unique in obtaining such benefits. Energy revenues currently recover only 15 to 20% of the costs. For a breakeven plant these electric revenues have to recover 50% of the cost, which can be accomplished through higher performance, higher energy prices and/or lower plant costs. Operating and maintenance costs of the current solar plants are also high. These O&M costs currently consume two-fifths of the gross revenues.

9.4 Near Term Construction Potential

The near term economics of the solar plant designs studied are found to be unfavorable in a competitive market environment. The largest cost gaps (costs minus benefits) are projected for the larger plants. This suggests that the operation of solar plants may be best demonstrated initially through relatively small plants. The scale and efficiency advantages of a large turbine might still be captured by operating a small solar facility in a hybrid made at a large fossil plant. Non-engineering issues appear to be very dominant in the near term solar economics. For example, the ability to take advantage of different tax benefits and site the plant in high energy rate areas are essential. The owners of the solar plant must have large tax liabilities and should have a long term vested interest in the development of competitive solar power plants. Involvements of utilities, equipment suppliers and A&E firms are thus considered very important. It is likely that near term solar power plants can only be expected in areas of high electric prices (e.g. California), favorable insolation regions and where plant ownerships are willing to take lower returns on their investment.

9.5 Competitive Plant Economics

Based on the four contract studies, either the current plant costs must be reduced to one-third (2/5th to 1/3rd) or the real energy prices must double (2 to 2.5 times) if there are to be many private funded, commercial solar plants. In actual practice, an equivalent combination of lesser improvements in cost, performance and energy prices may also provide for a competitive solar plants. The effect of collector cost reduction to \$80/m^2 is similar to reducing system costs to about three-fourths (70-80%). Demonstration of a net 25% overall plant efficiency is like improving system performance by 25%. Reductions in O&M costs by half is equivalent to an increase in system performance by about 20% (10-25%). The combined effect of these improvements would be as if real energy prices were doubled. Any increase in actual energy prices would be an additional benefit favoring the construction of solar plants. When improvements in solar thermal technology suggest competitive plant economics are in the near term, the private sector may temporarily accept lower returns on earlier SCR plants in order to achieve a strong market position for future SCR plants.

The above conclusions have been derived after reviewing, evaluating, normalizing, and analyzing the four SCR designs that are contained in some 15 volumes covering over 5500 pages of documentation. This body of information is the single most valuable data source on the design, performance and operation of SCR plants since the Barstow plant design although it contains several inconsistencies, possible biases, and suspect data. Further improvements in the quality of performance and cost data would make this information even more useful.

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